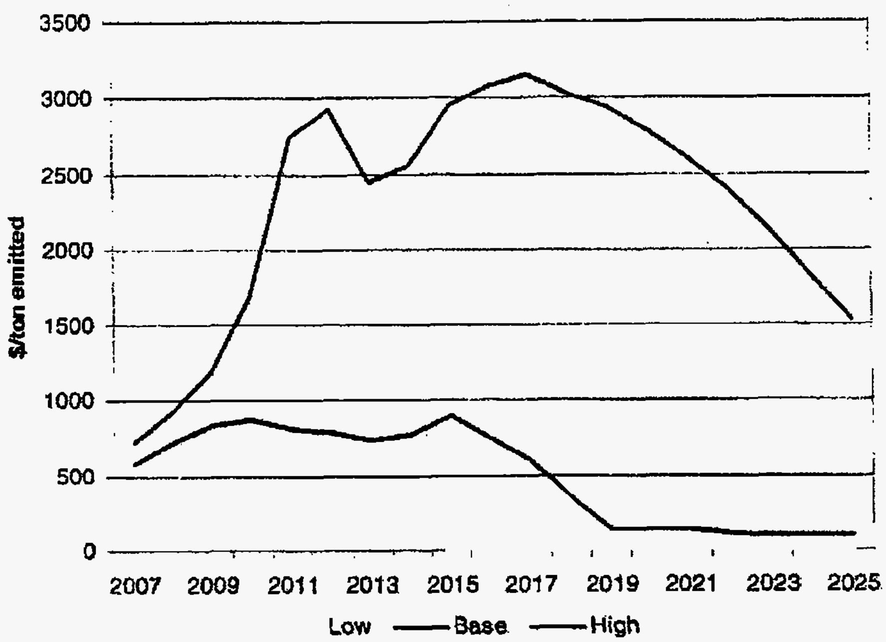
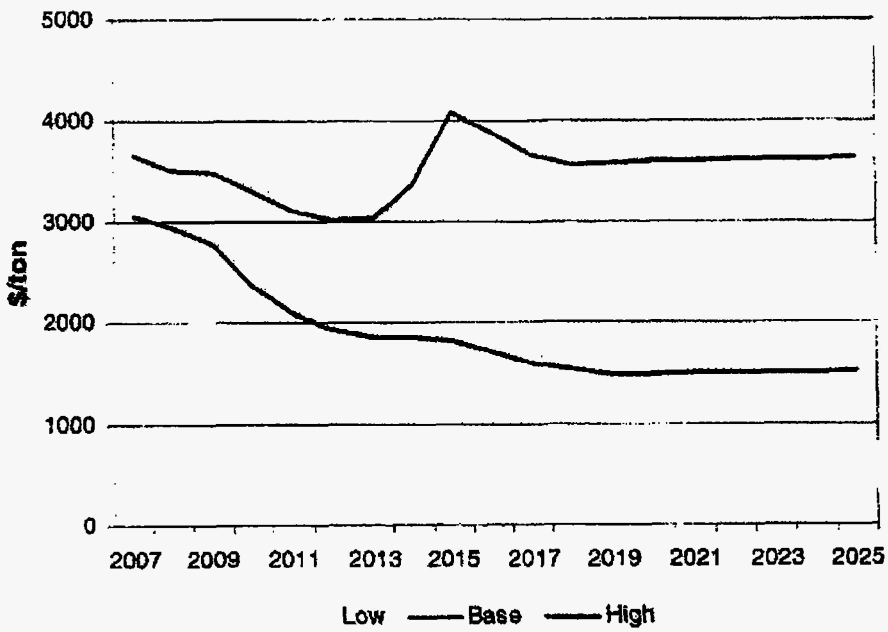
Figure 7. Uncertainty in SO_2 Allowance Prices



Sources: JD Energy

Figure 8. Uncertainty in NOx Allowance Prices

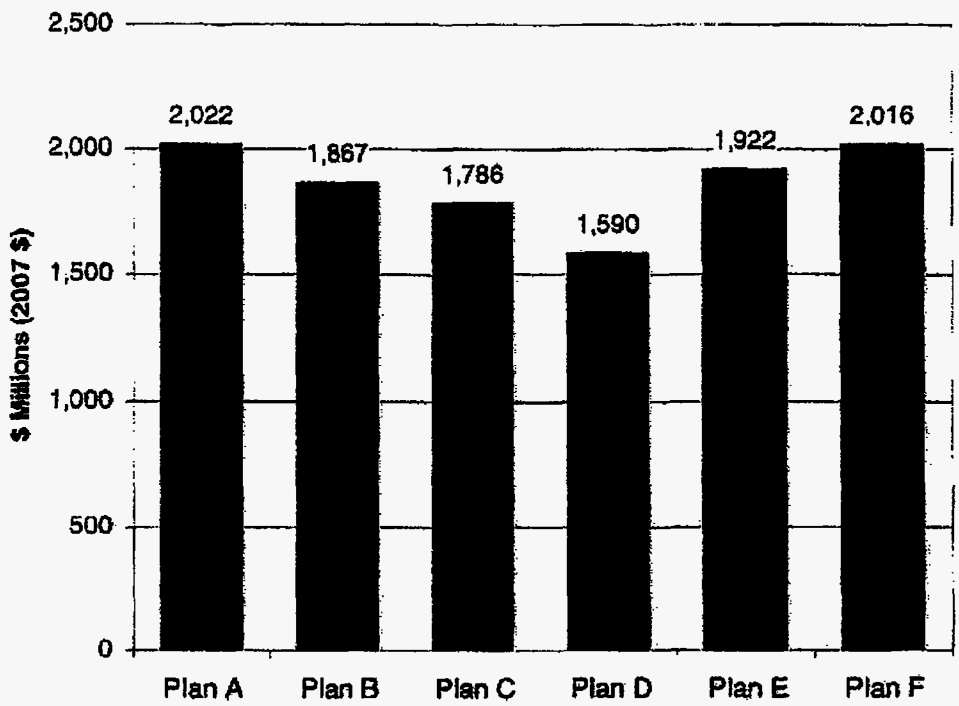


Source: JD Energy

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).

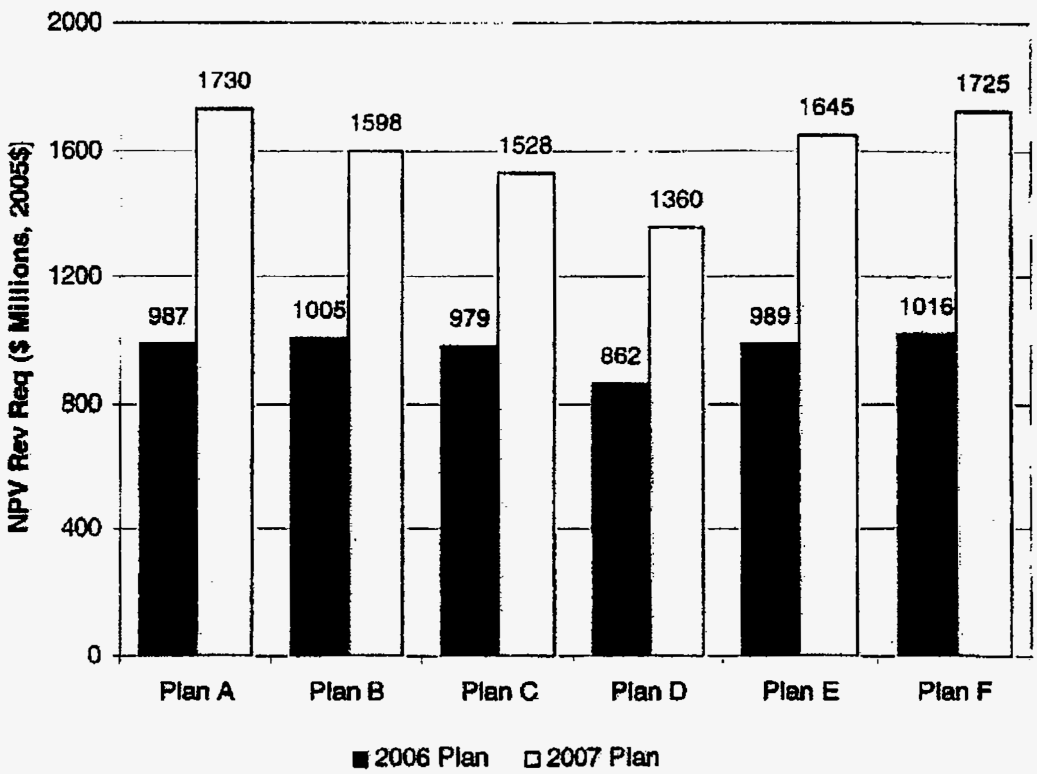
Figure 9. Comparison of Cumulative Present Value of Revenue Requirements



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.

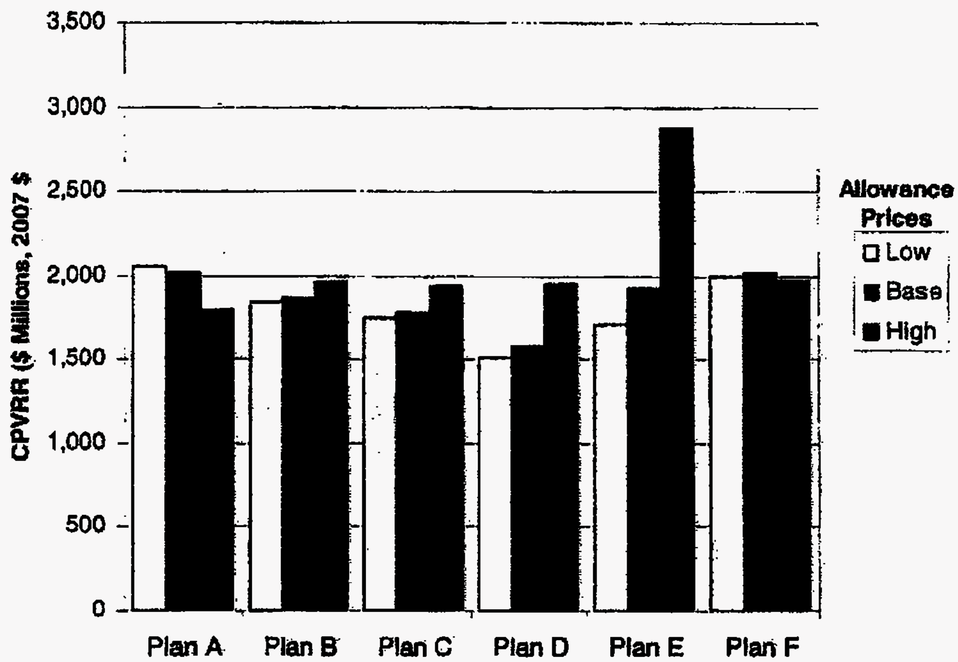
The CPVRR costs of the plans are now higher than what was projected in the 2006 Plan Report, as shown in Figure 10. The CPVRR cost of Plan D is now approximately 60% higher than the cost evaluation prepared for the 2006 Plan Report. As can be seen in the figure, the cost of the other plans increase by 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 economies 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. 1 2

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.

[redacted]

[redacted]

[redacted]

[redacted]

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

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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]

Principal Terms & Conditions

[redacted]

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[redacted]

[redacted]

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]

Key Terms & Conditions

[redacted]

[redacted]

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[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

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].

Principal Terms & Conditions

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[redacted]

[redacted]

<u>The Babcock & Wilcox Company</u>

<u>Name of Counterparty</u>: The Babcock & Wilcox Company ("B&W")

<u>Scope of Service</u>:

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.

<u>Selection Process</u>:

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.

<u>Cost</u>: [redacted]

<u>Principal Terms & Conditions</u>

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PROGRESS ENERGY FLORIDA
JURISDICTIONAL SEPARATION STUDY - TOTAL AT ISSUE=FPSC; ALL OTHER=FERC
FINAL SETTLEMENT COMPLIANCE COST OF SERVICE - FORECASTED 2006 TEST YR
INCLUDES ALL SETTLEMENT ADJS AND JJP REBUTTAL ADJUSTS
Final Settlement Compliance Version

DOCKET NUMBER: ER06COMP-000
EXHIBIT:
SCHEDULE: 12
PAGE: 1
ADJs: BCDEGHIJKLMNOPQRSTUVYZa

	ALLOCATORS	ITEM	ALLO	TOTAL ELECTRIC	TOTAL AT ISSUE	ALL OTHER
1	DEMAND, ENERGY & SPEC. ASSIGN.					
2	PRODUCTION BASE - % * 1000	K200		100,000	93,753	6,247
3	RATIO TO TOTAL ELECTRIC	K201		1.00000	0.93753	0.06247
4	PROD INTERMEDIATE - % * 1000	K202		100,000	79,046	20,954
5	RATIO TO TOTAL ELECTRIC	K203		1.00000	0.79046	0.20954
6	PRODUCTION PEAKING - % * 1000	K204		100,000	88,979	11,021
7	RATIO TO TOTAL ELECTRIC	K205		1.00000	0.88979	0.11021
8	TRANSM AVG 12 CP - % * 1000	K220		100,000	70,597	29,403
9	RATIO TO TOTAL ELECTRIC	K221		1.00000	0.70597	0.29403
10	DISTRIB PRIMARY - % * 1000	K240		100,000	99,597	403
11	RATIO TO TOTAL ELECTRIC	K241		1.00000	0.99597	0.00403
12	DISTRIB SECONDARY - % * 1000	K242		100,000	100,000	0
13	RATIO TO TOTAL ELECTRIC	K243		1.00000	1.00000	0.00000
14	DISTRIB SERVICE - % * 1000	K244		100,000	100,000	0
15	RATIO TO TOTAL ELECTRIC	K245		1.00000	1.00000	0.00000
16	DISTRIB METERS - % * 1000	K246		100,000	98,840	1,160
17	RATIO TO TOTAL ELECTRIC	K247		1.00000	0.98840	0.01160
18	LIGHTING FACILITIES - % * 1000	K248		100,000	100,000	0
19	RATIO TO TOTAL ELECTRIC	K249		1.00000	1.00000	0.00000
20	NO. OF IS CUSTOMERS	K252		153	150	3
21	RATIO TO TOTAL ELECTRIC	K253		1.00000	0.98039	0.01961
22	ENERGY AVG RATE SALES - %*1000	K306		100,000	95,765	4,235
23	RATIO TO TOTAL ELECTRIC	K307		1.00000	0.95765	0.04235
24	ENERGY EXCL D.A. TALL - %*1000	K312		100,000	91,626	8,374
25	RATIO TO TOTAL ELECTRIC	K313		1.00000	0.91626	0.08374
26	ASSIGN TO RETAIL - % * 1000	K400		100,000	100,000	0
27	RATIO TO TOTAL ELECTRIC	K401		1.00000	1.00000	0.00000
28	METER READING EXP - % * 1000	K410		100,000	97,536	2,464
29	RATIO TO TOTAL ELECTRIC	K411		1.00000	0.97536	0.02464
30	CUST RECORDS/COLL EXP - %*1000	K412		100,000	99,999	1
31	RATIO TO TOTAL ELECTRIC	K413		1.00000	0.99999	0.00001
32	BILLING/ACTG EXPENSE- % * 1000	K414		100,000	97,479	2,521
33	RATIO TO TOTAL ELECTRIC	K415		1.00000	0.97479	0.02521
34	ASSIGN TO WHOLESALE - % * 1000	K500		100,000	0	100,000
35	RATIO TO TOTAL ELECTRIC	K501		1.00000	0.00000	1.00000
36	WAGES AND SALARIES					
37	PRODUCTION DEMAND - BASE	K600	K200	50,668	47,503	3,165
38	PRODUCTIION DEMAND - INTERMED	K602	K202	11,379	8,995	2,384
39	PRODUCTION DEMAND - PEAKING	K604	K204	8,692	7,734	958
40	PROD ENERGY-D.A. WHOLE (STRAT)	K606	K500	2,396	0	2,396
41	PROD D&E- D.A. WHOLESALE (TAL)	K608	K500	697	0	697
42	PROD ENERGY - ALLOCABLE	K610	K306	41,984	40,206	1,778
43	TRANSMISSION	K612	T121	16,986	12,168	4,818
44	DISTRIBUTION	K614	D141	38,295	38,211	84
45	TOTAL PTD WAGES & SALARIES	K617		171,097	154,817	16,280
46	WTD PTD WAGE & SAL RATIOS	K619		1.00000	0.90485	0.09515
47	CUSTOMER ACCOUNTING	K620	K667	25,224	24,817	407
48	CUSTOMER SERV & INFO, SALES	K622	K400	2,056	2,056	0
49	ECCR	K624	K400	1,940	1,940	0
50	TOTAL PTDCSS WAGES & SALARIES	K627		200,317	183,630	16,687
51	WTD PTDCSS WAGE & SAL RATIOS	K629		1.00000	0.91670	0.08330
52	ADMINISTRATIVE & GENERAL	K630	K627	54,027	49,526	4,501
53	TOTAL WAGES AND SALARIES EXP	K633		254,344	233,156	21,188
54	WTD WAGE AND SALARY RATIOS	K639		1.00000	0.91670	0.08330
55	WEIGHTED CUST ACCOUNTG EXPENSE					
56	METER READING	K640	K410	15,076	14,705	371
57	CUSTOMER RECORDS	K642	K412	14,194	14,194	0
58	BILLING	K644	K414	11,154	10,873	281
59	TOTAL WEIGHTED CUST ACCTNG EXP	K667		40,424	39,772	652

12/15/05 09:24:19

Attachment 2

PEF-POD3-00050

33

PEF's Responses to Staff's Fourth Request for Production of Documents (Nos. 11-15)

OCT - 1 2009

BEFORE THE PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause	Docket No. 090007-EI Dated: October 1, 2009

PROGRESS ENERGY FLORIDA'S RESPONSES TO STAFF'S
FOURTH REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 11-15)

PROGRESS ENERGY FLORIDA, INC. ("PEF"), pursuant to Rule 28-106.206, Florida Administrative Code, Rule 1.350, Florida Rules of Civil Procedure, and the Order Establishing Procedure in this matter, hereby responds to Staff's Fourth Request for Production of Documents (Nos. 11-15):

RESPONSES

11. Please provide workpapers and documents to support your response to Interrogatory No. 25.

Response: Please see attachment POD 11.1 –Labor Cost Detail.

12. Please provide workpapers and documents to support your response to Interrogatory No. 26.

Response: Please see response to Interrogatory #26.

13. Please provide workpapers and documents to support your response to Interrogatory No. 27 (c).

Response: Please see the attached contract for Terra Environmental Technologies (Bates Nos. PEF-POD4-00084- PEF-POD4-00131).

14. Please provide workpapers and documents to support your response to Interrogatory No. 28 (a).

Response: Please see attachment POD 14.1 – Cap Expenditures Breakout.

15. Please provide workpapers and documents to support your response to Interrogatory No. 28 (d).

Response: Please see the attached contracts for Mesa Engineering (Bates Nos. PEF-POD4-00001- PEF-POD4-00083) and Evaptech (Bates Nos. PEF-POD4-00132- PEF-POD4-00306).

SERVED this 1st day of October, 2009.

HOPPING GREEN & SAMS, P.A.

By: Gary

Gary V. Perko, Esquire
Florida Bar No. 855898
P.O. Box 6526
Tallahassee, FL 32301
(850) 222-7500

Attorneys for Progress Energy Florida, Inc.

PEF'S RESPONSE TO STAFF'S FOURTH REQUEST FOR PRODUCTION OF DOCUMENTS NO.11

	A	B	C	D	E	F
1	2010 O&M Labor and Overtime					
2	EBC nonbu		2010	Percentage	2010	
3	EUR bu			Rate of	OT	[redacted]
4	Res Type	Position	Pay	Overtime	Salary	
5	EBC	Controls Lead	[redacted]	3.00%	[redacted]	[redacted]
6	EBC	Principle Engineer- Scrubber	[redacted]	0.00%	[redacted]	[redacted]
7	EBC	Lead PdM Specialist-POG	$ 86,419.20	3.00%	$ 2,592.58	
8	EBC	Electrical-I/C Lead	[redacted]	3.00%	[redacted]	[redacted]
9	EBC	Ops Ld/Shift Sup-1	[redacted]	3.00%	[redacted]	[redacted]
10	EBC	Shift Supv - 2	[redacted]	3.00%	[redacted]	[redacted]
11	EBC	Shift Supv - 3	[redacted]	3.00%	[redacted]	[redacted]
12	EBC	Shift Supv - 4	[redacted]	3.00%	[redacted]	[redacted]
13	EBC	Shift Supv - 5	[redacted]	3.00%	[redacted]	[redacted]
14	EBC	Clean Air O&M Superintendant	[redacted]	0.00%	[redacted]	[redacted]
15	EBC	Lead Work Management Specialist	$ 86,419.20	3.00%	$ 2,592.58	
16	EBC	Environmental Analyst	[redacted]	3.00%	[redacted]	[redacted]
17	EUR	[illegible] Mech (SH)	[redacted]	13.00%	[redacted]	[redacted]
18	EUR	Cert Welder/Mech (SH)-1	[redacted]	13.00%	[redacted]	[redacted]
19	EUR	Cert Welder/Mech (SH)-2	$ 66,977.16	13.00%	$ 8,707.03	
20	EUR	Mechanic (SH)	$ 66,118.20	13.00%	$ 8,595.37	
21	EUR	Cert Welder/Mech (SH)-3	$ 66,977.16	13.00%	$ 8,707.03	
22	EUR	Cert Welder/Mech (SH)-4	$ 66,977.16	13.00%	$ 8,707.03	
23	EUR	Chief Electrician-1	[redacted]	13.00%	[redacted]	[redacted]
24	EUR	Control Tech (SH)-1	[redacted]	13.00%	[redacted]	[redacted]
25	EUR	Electrician-Prod (SH)-1	$ 66,118.20	13.00%	$ 8,595.37	
26	EUR	Control Tech (SH)-2	$ 66,118.20	13.00%	$ 8,595.37	
27	EUR	Electrician-Prod (SH)-2	$ 66,118.20	13.00%	$ 8,595.37	
28	EUR	Control Tech (SH)-3	$ 66,118.20	13.00%	$ 8,595.37	
29	EUR	Scrubber Operator (SH)-1	$ 67,707.27	13.00%	$ 8,801.95	
30	EUR	Scrubber Operator (SH)-2	$ 67,707.27	13.00%	$ 8,801.95	
31	EUR	Scrubber Operator (SH)-3	$ 67,707.27	13.00%	$ 8,801.95	
32	EUR	Scrubber Operator (SH)-4	$ 67,707.27	13.00%	$ 8,801.95	
33	EUR	Scrubber Operator (SH)-5	$ 67,707.27	13.00%	$ 8,801.95	
34	EUR	Scrubber Operator (SH)-6	$ 67,707.27	13.00%	$ 8,801.95	
35	EUR	Scrubber Operator (SH)-7	$ 67,707.27	13.00%	$ 8,801.95	
36	EUR	Scrubber Operator (SH)-8	$ 67,707.27	13.00%	$ 8,801.95	
37	EUR	Apprentice Scrubber Operator (SH)-1	$ 55,875.14	13.00%	$ 7,263.77	
38	EUR	Apprentice Scrubber Operator (SH)-2	$ 55,875.14	13.00%	$ 7,263.77	
39	EUR	Apprentice Scrubber Operator (SH)-3	$ 55,875.14	13.00%	$ 7,263.77	
40	EUR	Apprentice Scrubber Operator (SH)-4	$ 55,875.14	13.00%	$ 7,263.77	
41	EUR	Apprentice Scrubber Operator (SH)-5	$ 55,875.14	13.00%	$ 7,263.77	
42	EUR	Apprentice Scrubber Operator (SH)-6	$ 55,875.14	13.00%	$ 7,263.77	
43	EUR	Apprentice Scrubber Operator (SH)-7	[redacted]	13.00%	[redacted]	[redacted]
44	EUR	Apprentice Scrubber Operator (SH)-8	[redacted]	13.00%	[redacted]	[redacted]
45	EUR	Apprentice Scrubber Operator (SH)-9	[redacted]	13.00%	[redacted]	[redacted]
46	EUR	Special Lab Tech (S)-1	$ 65,345.14	13.00%	$ 8,494.87	
47	EUR	Apprentice Scrubber Operator (SH)-10	[redacted]	13.00%	[redacted]	[redacted]
48	EUR	Apprentice Scrubber Operator (SH)-11	[redacted]	13.00%	[redacted]	[redacted]
49	EUR	Scrubber Operator (SH)-9	$ 67,707.27	13.00%	$ 8,801.95	
50	EUR	Scrubber Operator (SH)-10	[redacted]	13.00%	[redacted]	[redacted]
51	EUR	Scrubber Operator (SH)-11	[redacted]	13.00%	[redacted]	[redacted]
52	EUR	Scrubber Operator (SH)-12	[redacted]	13.00%	[redacted]	[redacted]
53	EUR	Scrubber Operator (SH)-13	[redacted]	13.00%	[redacted]	[redacted]
54	EUR	Scrubber Operator (SH)-14	[redacted]	13.00%	[redacted]	[redacted]
55	EUR	Special Lab Tech (S)-2	$ 65,345.14	13.00%	$ 8,494.87	
56						
57						
58		Total EBC Labor	907,142.66	[redacted]	21,856.41	928,999.07
59		EBC Labor Less Exc Hrs.		[redacted]	[redacted]	
60		Exceptional Hours		[redacted]	[redacted]	
61				[redacted]	[redacted]	
62		Total EUR Labor	2,280,535.67	[redacted]	296,469.64	2,577,005.31
63		EUR Labor Less Exc Hrs		[redacted]	[redacted]	
64		Exceptional Hours		[redacted]	[redacted]	
65				[redacted]	[redacted]	
66				[redacted]	[redacted]	
67		51		[redacted]	[redacted]	
68		Total Base Labor	3,187,678.34	[redacted]	318,326.04	3,506,004.38

PEF'S RESPONSE TO STAFF'S FOURTH REQUEST FOR PRODUCTION OF DOCUMENTS NO.13

CR No. 830643

CONTRACT

406464

BETWEEN

PROGRESS ENERGY SERVICE COMPANY, LLC
not in its individual capacity, but solely as agent for

PROGRESS ENERGY FLORIDA, INC.

AND

TERRA ENVIRONMENTAL TECHNOLOGIES INC.

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31	Background Investigation and Drug Screen
32	Workplace Violence Prevention
33	Electronic Transmittals

Attachment A	Scope of Work
Attachment	Code of Ethics Acknowledgment Form
Attachment	Code of Ethics Compliance Plan
Attachment	Background Investigation and Drug Screen Compliance Plan
Attachment	Supplier Diversity & Business Development Subcontracting Report

CONTRACT NO. 406464

This Contract (hereinafter "Contract"), effective January 1, 2009, by and between PROGRESS ENERGY SERVICE COMPANY, LLC, whose address is 410 South Wilmington Street, Raleigh, NC 27601, not in its individual capacity, but solely as agent for PROGRESS ENERGY FLORIDA, INC. (hereinafter referred to as "Owner"), and TERRA ENVIRONMENTAL TECHNOLOGIES INC. corporation, whose office is located at 600 Fourth Street, Sioux City, Iowa 51102 (hereinafter referred to as "Contractor").

In consideration of the work to be done by Contractor, the payments to be made by Owner, and the other promises set forth below, the parties agree as follows:

SECTION 1. SCOPE OF WORK

Contractor shall furnish all required labor, tools, equipment, material, parts, transportation, and supervision necessary to perform the following work at Owner's Crystal River Units 4 and 5 and includes, but is not limited to, the following:

See Attachment A for a detailed scope of work (hereinafter "Work").

All Work shall be performed as directed by Owner's Designated Representative consistent with the terms of this Contract.

SECTION 2. SCHEDULE OF WORK

[redacted] 1 2

SECTION 3. COMMENCEMENT OF WORK

Contractor shall not commence the Work and Owner shall not be obligated to pay Contractor for Work commenced prior to Contractor satisfying the insurance requirements and providing Owner with an acceptable Certificate of Insurance as set forth in Section 20. Insurance.

SECTION 4. OWNER'S DESIGNATED REPRESENTATIVE

As used in this Contract, "Owner's Designated Representative" means Mr. Todd Mills at Owner's Crystal River Plant who is the liaison between Owner and Contractor during performance of the Work. No agreement with Owner's Designated Representative shall affect or modify any of the terms or obligations contained in this Contract, except as provided in Section 6. Changes. A copy of all correspondence concerning the Work shall be sent to Owner's Designated Representative. Owner reserves the right to change its Designated Representative at any time.

SECTION 5. COMPENSATION

A. Pricing, Pricing Methods, and Conditions

Contractor may submit invoices monthly in arrears for performance by Contractor of the Work described above in the previous month, and Owner will pay Contractor, as full compensation for such Work performed to Owner's satisfaction under this Amendment in the period covered by such invoice, in accordance with the Fees described in Section 2 in Exhibit A to Attachment A.

B. Sales and Use Taxes

Contractor assumes exclusive liability for all sales or use taxes applicable to any materials, supplies, equipment or tools purchased, rented, leased, used or otherwise consumed by Contractor in conjunction with the performance of the Work.

Owner holds a "Florida Pollution Control Affidavit." This certificate exempts Owner from Florida sales or use tax on purchases of all qualified property and/or labor. The appropriate affidavit is hereby furnished to Contractor for use on this Contract only. Therefore, Contractor shall not include sales or use tax in the Contract price or on its invoices to Owner.

C. Invoices and Payments

When Work is completed and performed in accordance with this Contract, payment of the agreed upon compensation will be made by Owner. All payments are subject to adjustment on the basis of any final accounting which may be made by Owner. Owner may withhold from any payment: (1) any amounts incorrectly invoiced; (2) any amount in dispute; until the dispute is resolved(3) or an amount sufficient to completely protect Owner from any loss, damage or expense arising out of assertions by other parties of any claim or lien against Owner arising in connection with the Work, (4) any amount due under the indemnity provisions of this agreement. The undisputed portion of any invoice will be paid by Owner as hereinafter provided.

Invoices for Work performed under this Contract shall be sent to Mr. Todd Mills at Owner's Crystal River Plant. Each invoice and all supporting documents shall show the Owner Contract number. Invoice items must be identifiable to the pricing schedule in order to be accepted for payment.

If requested by Owner, Contractor shall supply a general release of all third party claims or liens related to the authorized Work excluding direct party to party general liability releases, or affidavits that all bills for materials and labor have been paid and receipts showing the payment of these bills. Failure or refusal by Contractor to comply with such request shall excuse Owner from making any further payments to Contractor until Contractor does comply.

Each invoice shall indicate materials furnished and delivered to the site. Original bills of handling or shipping receipts for materials shall be attached to any invoice requesting payment for materials. When transportation is prepaid, original transportation receipts must also be attached to the invoices.

Subject to the above conditions all payments, excluding final payment, will be made not later than thirty (30) days after receipt of Contractor's invoice. Final payment shall be made not later than thirty (30) days after receipt of Contractor's invoice and all of the following have been completed:

(1) All Work has been completed and accepted and receipt of all required documentation by Owner.

(2) A correct invoice covering the Work has been presented to Owner.

D. Not Used

E. Overbillings/Offsets/Credits/Refunds

Owner may charge and collect interest from the Contractor on any overbillings, offsets, credits or refunds that may become due to Owner under this Contract. Interest shall be paid at the rate of the average prime rate of interest as listed in the Wall Street Journal Money Rates Section. Interest shall cover the period of time from the date the overpayment, error or basis for refund or offset occurred to the date the amount is paid. The Contractor may be notified of the overbilling by credit memorandum or by invoice. Payment of the total overbilling, offset, credit or refund plus interest shall become due to Owner immediately upon Contractor's receipt.

SECTION 6. CHANGES

As soon as reasonably possible, not to exceed ten (10) calendar days from receipt of a request from Owner's Designated Representative, Contractor shall provide Owner with a fixed price quotation or cost estimate for any change under consideration by Owner, including any necessary adjustments to the schedule. Owner's Designated Representative may, at any time and without notice to any surety Contractor may have, provide Contractor with a written field directive to make changes in, additions to or omissions from the authorized Work or the schedule, and Contractor shall promptly proceed with the performance of this Contract as so changed. Any field directive issued by Owner's Designated Representative shall only change the description of the Work or the schedule and shall not affect or change any other terms or conditions of this Contract. If Contractor becomes aware of a change in the Work or the schedule specified in this Contract that it feels is necessary, it shall request a written field directive for the proposed change. Any claim for equitable adjustment of the compensation as a result of the change, addition or omission must be submitted to Owner within ten (10) calendar days from the date the written field directive is issued.

Any claims submitted by Contractor because of a change by Owner must be itemized and supported with adequate documentation. Work performed outside the scope or schedule set forth in this Contract which is not requested by a written field directive shall not form the basis of a claim for additional compensation. Any increase or decrease in compensation paid for changes in the Work shall not be binding on Owner unless and until a Contract Amendment is executed by both parties.

It is understood and agreed by the parties that Contractor has examined all available records and informed itself about conditions to be encountered, the character of equipment and facilities required to perform the Work, the labor conditions and all other relevant matters in connection with the Work to be performed prior to agreeing to a fixed price on this Contract. It is further understood and agreed that the price is based on Contractor's own knowledge and judgment of conditions, problems, volumes, and other factors and not upon any representations of Owner. Any information or estimates which are made available by Owner to Contractor shall have no express or implied guarantee of accuracy or usefulness. Contractor agrees that it will form its own opinion of the costs it will incur in undertaking the Work. Therefore, Contractor agrees that the fact the actual amount of Work performed or costs incurred differs from estimates made by either Contractor or Owner shall not be a basis for change in compensation.

SECTION 7. FINANCIAL AUDITS

Contractor shall maintain accurate and detailed records, in accordance with generally accepted accounting principles consistently applied, of all expenditures or costs relating to any Work performed under this Contract as may be necessary for Owner to verify pricing of product provided by Contractor hereunder. Owner shall have the right to inspect, examine and make copies of any or all books, accounts, records and other writings of Contractor relating to the performance or cost of the Work. If the Work is being performed on a fixed-price basis only, Owner shall have the above-specified rights only upon termination or suspension of the Work. Such audit rights shall be extended to Owner or to any representative designated by Owner. Audits shall take place at times and locations mutually agreed upon by both parties, although Contractor must make the materials to be audited available within one (1) week of the request for them. Costs incurred in undertaking the audit will be borne by Owner but costs incurred by Contractor as a result of Owner's exercising its right to audit will be borne by Contractor.

SECTION 8. WARRANTY AND INSPECTION OF MATERIALS

Contractor warrants that all Work performed under this Contract shall be undertaken in a good and workmanlike manner and shall conform to the requirements specified. Contractor further warrants that the Work shall be of good quality, free from defects in design, material and workmanship, and shall be fit for its intended use. Any professional services provided by Contractor in connection with the Work shall be performed in accordance with generally accepted standards and practices then prevailing in the industry. Contractor warrants that unless otherwise specified all parts, material and equipment it supplies will be new. Work performed, and all parts, material and equipment furnished in connection with this Contract shall at all times, and at all locations, be subject to inspection by Owner or its representatives, regardless of where the Work is being performed.

If at any time Owner's Designated Representative determines that Contractor's methods or equipment are inadequate for ensuring the requisite quality of Work, Owner's Designated Representative may order Contractor to increase its adequacy and Contractor shall improve its methods or change its equipment or work force so as to give reasonable assurance of compliance with the order. Failure of Owner's Designated Representative to make this demand shall not relieve Contractor of its obligation to ensure the quality of the Work.

When any Work fails to conform with the requirements of this warranty, it shall be corrected and made satisfactory to Owner at no cost to Owner. Contractor shall commence correction of defective Work immediately upon notification of the defect, unless a different time is specified by Owner's Designated Representative. Contractor shall continuously and diligently pursue the repair or corrective Work until it is completed to the reasonable satisfaction of Owner. Failure on the part of Owner to refuse or reject Work or materials prior to acceptance of or payment for the Work shall not bar Owner at any subsequent time from requiring the Work to be corrected or from recovering damages arising out of any defective Work.

If Contractor fails to commence and pursue corrective action as hereinabove provided, or in the event of an emergency situation where correction of the defect by Contractor is not practical, Owner may correct the defect itself or hire others to do so, and all reasonable costs incurred by Owner shall be paid by Contractor.

SECTION 9. RESPONSIBILITY FOR WORK

Contractor is responsible for and shall bear all risk of loss or damage to Work, and all materials, tools and equipment delivered to the Work location by Contractor or its suppliers, until the expiration date of the Contract is reached, unless the loss or damage results solely from the negligence of Owner. Owner is not responsible for any loss or damage to the Work, or to materials, tools and equipment of Contractor resulting from a tortious act or omission of any other contractor.

Contractor shall be responsible, at no additional cost to Owner, for taking all precautions necessary to prevent damage or injury to the Work of Contractor, Owner or its contractors, and to the property of Contractor, Owner, other contractors, or any of their employees, and members of the general public.

Asbestos Containing Material (ACM) shall not be used by Contractor or his subcontractors in any Work performed under this Contract unless specifically agreed to in writing by Owner's Designated Representative prior to the start of the Work

SECTION 10. CLEANUP

Contractor shall be responsible for keeping the area where its employees and subcontractors are working clean at all times. If Contractor fails or refuses to maintain a clean Work area, Owner may perform or arrange to have performed a cleanup of the area. If Owner incurs any cost performing cleanup of Contractor's Work, that cost times a factor sufficient to cover Owner's then applicable administrative and general overhead costs shall be paid to Owner or may be deducted by Owner from any amount owed to Contractor.

SECTION 11. TERMINATION AND SUSPENSION

A. Termination for Cause

The following actions by Contractor shall give Owner the right to terminate the Contract after fifteen (15) calendar days' written notice to Contractor:

(1) Contractor fails to carry forward and complete Work as rapidly as required, or if no deadlines are set, as rapidly as Owner determines is required or that the circumstances will permit.

(2) Contractor fails to comply with applicable laws, regulations or ordinances.

(3) Contractor becomes involved in a labor problem which in the opinion of Owner impedes or slows down the Work.

(4) Contractor fails to commence correction of defective Work immediately after notification of defect or as otherwise specified by Owner and to continuously and diligently pursue correction of defect until the Work is completed to the full satisfaction of Owner.

(5) Contractor in any way materially breaches the terms of this Contract.

(6) Contractor makes a general assignment for the benefit of its creditors.

(7) Contractor has a receiver appointed because of insolvency.

(8) Contractor files bankruptcy or has a petition for involuntary bankruptcy filed against him.

(9) Contractor fails to make prompt payments for materials or labor used on Contract Work.

(10) Contractor fails to comply with Owner's safety standards.

It is agreed that if Owner exercises its right to terminate this Contract for any of the above reasons, the termination shall not prejudice any other right or remedy available to Owner. If Owner terminates for cause, Contractor shall be responsible for all reasonable, documented costs and expenses incurred by Owner in hiring another contractor to complete the Work beyond those agreed to in the pricing section.

B. Termination for Convenience

Owner shall have the right to terminate this Contract in whole or in part at any time, including prior to commencement of any Work, for Owner's convenience. Upon receiving notice of termination, Contractor shall discontinue the Work on the date and to the extent specified in the notice and place no further orders for materials, equipment, services or facilities except as needed to continue any portion of the Work which was not terminated. Contractor shall also make every reasonable effort to cancel, upon terms satisfactory to Owner, all orders or subcontracts related to the terminated Work.

In paying Contractor for Work performed under this Contract when terminated for Owner's convenience, Owner will make payments to Contractor as follows:

(1) If this Contract is terminated prior to Contractor's having commenced any Work or preparation for Work, no payment will be made to Contractor.

(2) If this Contract is terminated after the Contractor has commenced mobilization or other off-site activities but prior to any performance of the authorized Work, Owner will pay Contractor the actual cost, including administrative and general overhead, of any preparation to perform the authorized Work that cannot be recovered by Contractor in future Work done for Owner or otherwise. This paragraph does not apply to engineering, design, fabrication or other off-site Contractor expenditures that are actually part of the Work rather than preparation to perform the Work.

(3) If this Contract is terminated for Owner's convenience after commencement of the authorized Work, then except as provided in (4) below, Owner shall pay Contractor for Work performed prior to termination as follows:

> Where Work is to be performed on a fixed-price basis, Contractor will be paid its actually incurred costs, including administrative and general overhead costs and demobilization costs, determined in accordance with generally accepted accounting principles consistently applied, plus an amount equal to ten percent (10%) of those costs to account for profit. Notwithstanding the above, Owner will not pay an amount for costs actually incurred which unreasonably exceeds the percentage of total costs as compared to the percentage of total Work completed prior to termination. In no event will Owner pay Contractor an amount that exceeds the fixed price.
>
> For Work, including demobilization, where payment is on a unit price basis, or a time-and-materials basis, Contractor will be compensated at the rates specified in the Contract. If profit is included in the authorized rates no additional payments will be made for anticipated profits; if profit is not included in the rates, the amount paid will be increased by ten percent (10%) to account for profit. Notwithstanding the above, Owner will not pay for time worked by Contractor's employees which as a percentage of total anticipated hours to be worked unreasonably exceeds the percentage of Work completed prior to termination.

(4) If (1) at the time of termination Contractor has prepared or fabricated any goods or purchased or leased any materials or equipment intended for subsequent incorporation into the Work, and (2) these goods or materials cannot be incorporated into any other Work for Owner or otherwise, then Contractor will be paid for the actual cost of the goods or materials.

(5) Contractor agrees that it has an affirmative duty to mitigate all damages to it upon termination of the Contract. In no event shall Owner be responsible to pay Contractor for its anticipated profits or any sales commissions.

(6) Contractor shall maintain adequate documentation to support its claim for payment. Any part of Contractor's claim that is not supported by adequate documentation will not be paid by Owner. Payment of the amounts specified above shall be Contractor's sole and exclusive remedy for termination of Work for Owner's convenience.

SECTION 12. PATENTS AND COPYRIGHTS

Contractor agrees that in performing this Contract it will not use or provide to Owner, unless specified or directed by Owner, any process, program, document, data, design, device or material which infringes on any patent, copyright, trade secrets, or any other proprietary right of any third party. Contractor agrees to indemnify and defend Owner, at Contractor's expense, against any suit or proceeding brought against Owner for any infringement arising out of Contractor's Work under this Contract, excluding therefrom Work containing any process, program, document, data, design, device or material specified or requested by Owner. Owner will promptly notify Contractor in writing of any such suit or proceeding and will assist Contractor in defending the action by providing any necessary information at Contractor's expense. If use of the Work is enjoined, then Contractor shall obtain a license for Owner to continue using the Work, or modify the Work so that it no longer infringes, without degrading its function or performance.

SECTION 13. STATUS OF CONTRACTOR

It is the intent of the parties to create between them the relationship of owner and independent contractor. It is agreed that nothing shall operate to change or alter such relationship, except a further agreement in writing between them.

SECTION 14. SUBLETTING OR ASSIGNING CONTRACT

Contractor shall not sublet any portion of the Work or assign the Contract without first submitting the proposed subcontract or assignment to Owner's Designated Representative and receiving written consent from Owner's Designated Representative to subcontract or assign, which consent shall not be unreasonably withheld. Any assignment without the consent of Owner shall be void. A request to sublet or assign must contain the name and location of individuals or firms to whom Work will be sublet or to whom the Contract is to be assigned, information on the qualifications and experience of those individuals or firms to perform the Work, and an estimate of the cost of the Work to be performed by the subcontractor or assignee. The general terms and conditions of this Contract and any Contract Amendment regarding the Work to be performed must be incorporated into and attached to any subcontract or assignment. Consent to subletting or assignment will not relieve Contractor of responsibility for the performance of Work in accordance with the terms and conditions of this Contract and any Amendments executed by both parties. In the event of an emergency, contractor may sublet or contract certain services as necessary to restore the Terminal to normal operation without consent. In such case Contractor will inform Owner's Designated Representative of such activity within 48 hours after the start of any subcontracting activity.

SECTION 15. REPORTS

Whenever requested by Owner, Contractor shall furnish within a reasonable period of time, in the manner directed, and at no additional cost to Owner, written reports about the Work. Owner may require these reports to show the progress or status of the Work or any other matter pertaining to it.

SECTION 16. TOOLS, MATERIALS AND EQUIPMENT

Contractor shall equip all employees with all tools and equipment necessary to perform the Work unless otherwise expressly provided in this Contract. All tools and equipment belonging to Contractor or its employees shall be clearly marked as to their owner. Contractor shall provide storage facilities for all tools and equipment at or near the job site, other than those facilities and work shop provided by Owner. Storage facilities on the site shall be located in a place approved by Owner's Designated Representative.

When requested in writing, Contractor agrees to purchase special equipment or tools or furnish them on a rental basis. The purchase price or rental cost of such equipment and/or tools and the basis of payment will be as agreed upon, if not previously established in the Contract Rate Schedule. Any tools specifically purchased for authorized Work and paid for by Owner are the property of Owner and shall be turned over to Owner upon completion of the Work.

SECTION 17. NOT USED

SECTION 18. PLANS, DRAWINGS, SPECIFICATIONS, AND DOCUMENTATION

Contractor shall keep during the Contract term plans, drawings, specifications, or documentation for the Work. Contractor shall keep one copy of the documents at the jobsite and shall produce the copy upon request of Owner's Designated Representative.

Upon expiration of the Contract term, Contractor shall return all listed drawings, specifications, and documentation to Owner

SECTION 19. CONTRACTOR PERSONNEL MATTERS

Personnel provided by Contractor under this Contract shall at all times remain the sole responsibility of said Contractor for purposes of personal and professional liability.

Contractor is solely responsible for all aspects of the labor relations of its personnel, including but not limited to, wages, benefits, discipline, hiring, firing, promotions, pay raises, overtime and job and shift assignments. Owner shall have no responsibility for or power over these areas. Such personnel shall be and remain the employees of Contractor at all times.

All personnel to be provided by Contractor under this Contract shall be employees of Contractor or its approved subcontractors and shall not be independent contractors. Contractors shall withhold from each employee's pay sufficient funds for federal, state, and local income taxes, funds required by the Federal Insurance Contributions Act, and as may otherwise be required by applicable law. Contractor further agrees to defend, indemnify, and hold Owner harmless from any claims, fines, and penalties based on any allegations that such withholdings were not made, or that such withholdings were inadequate.

Contractor shall comply with the Fair Labor Standards Act, and shall pay overtime to its employees as required by all applicable federal, state and local laws, rules, regulations, and ordinances. In the event that Contractor fails to comply with this requirement, Contractor shall be required to indemnify, defend and hold Owner harmless from all claims, actions, fines, penalties, and liabilities resulting from any such failure.

In selecting employees to undertake any Work, Contractor shall select only those persons who are qualified by the necessary education, training and experience to provide a high quality performance of the Work. If Owner determines, in its sole discretion, that any personnel supplied by Contractor are unsuitable for the Work, Owner shall so advise Contractor and Contractor shall remove that employee from the premises and assign other individuals to perform the Work. If Owner determines, in its sole discretion, that the presence on Owner's premises of any employee of Contractor is not consistent with the best interest of Owner, Owner may direct Contractor to remove that employee from performing Work under this Contract. Contractor shall assign another employee to work in place of the unacceptable employee.

Replacement of employees under either of the above circumstances shall be at no cost to Owner. Contractor shall absorb any travel costs or travel time to the site for the replacement employee and from the site for the replaced employee. Contractor shall give Owner advance notice prior to removing Contractor's supervisory or professional personnel from the job.

Contractor recognizes the importance of the safety of all workers at the Work site and agrees that accident prevention shall be an integral part of Contractor's operation. Contractor shall provide and maintain adequate first-aid facilities and shall cooperate with all other contractors at the site and with Owner in their respective safety programs. Contractor shall furnish all reasonable information concerning the safety of its operations as may be required by Owner's Designated Representative, including records of accidents to employees, and time lost due to accidents. In the event that Owner discovers a condition or Work practice that it considers to be unsafe, Owner may suspend the Work in whole or in part without cost until the unsafe condition or Work practice is made safe.

Contractor's employees' vehicles and Contractor's vehicles and equipment shall be parked in areas expressly approved by Owner's Designated Representative, when parking on Owner owned or controlled property.

Contractor's employees shall be properly dressed to Owner's standards at all times while on Owner's Work site. Employees not properly dressed will be refused entry to or will be subject to discharge from the Work site.

When sanitary facilities are furnished by Owner, Contractor's employees shall use only those designated and approved by Owner's Designated Representative.

Use of Non-English Speaking Workers

Prior to the beginning of any task under this Contract, the Contractor shall notify Owner if it anticipates using any non-English speaking personnel at Owner's facilities. If such personnel are used, the Contractor shall provide an on-site bilingual person to translate the site orientation and safety information training. Contractor shall be solely responsible for ensuring that the non-English-speaking workers are fully trained and understand the site orientation and safety information. In addition, any time the Contractor's non-English speaking workers are present at a Owner facility, the Contractor shall provide at least one bilingual person in each applicable work crew capable of both communicating in English and instructing the non-English speaking workers. The Contractor shall specifically identify these bilingual interpreters to Owner Designated Representative. For this purpose, a work crew is defined as any worker or group of workers in any specific location on Owner property, regardless of how the Contractor organizes his work force.

Owner may assist in facilitating communication of important safety information by offering bilingual versions of safety brochures or video presentations. If these are available, it in no way relieves the Contractor of providing the interpreter services stated above.

Code of Ethics

Contractor, Contractor's employees, and employees of Contractor's subcontractor(s) performing Work under this Contract shall comply with Owner's Code of Ethics. Owner will make the Code of Ethics available to Contractor in order for Contractor to provide a copy to any employee with (i) a presence for a single period of 15 calendar days or more upon property owned or leased by Owner (except right-of ways) or any of Owner's subsidiaries or affiliates and/or (ii) access to Owner's business critical infrastructure and/or (iii) security badge access to Owner facilities. Each such employee shall sign an Acknowledgment Form in substantially the form set forth by Owner. Contractor shall retain the signed forms for Owner audit purposes for the term of the Contract plus one (1) year. The audit right provided herein shall not be restricted by any other audit provisions of the Contract. Contractor shall not be required to obtain signatures on Acknowledgement Forms for those employees assigned to Owner sites exclusively to provide storm support.

Contractor, Contractor's employees, and employees of Contractor's subcontractor(s) performing Work under this Contract are obligated to comply with all applicable laws and regulations and with all applicable health, safety and security rules, programs and procedures. The Owner Code of Ethics identifies principles concerning lawful and ethical conduct that must be followed by Contractor's employees in the performance of Work. The Code of Ethics also provides for an AlertLine reporting mechanism that enables the reporting of suspected violations of law and of the Code of Ethics as a part of Owner's program to prevent and detect violations of law and criminal or unethical conduct.

In order for Owner to confirm Contractor's compliance with the Code of Ethics requirements in this Contract, Contractor is required to complete the Code of Ethics Compliance Plan attached. This Plan identifies the points of contact within Contractor's organization and other information for Owner to use in verifying Contractor's compliance. Should any information on the Compliance Plan change during the term of the Contract, Contractor shall notify Owner's Designated Representative in writing within thirty (30) days of the change.

SECTION 20. INSURANCE

Contractor shall provide and maintain in full force and effect at no additional cost to Owner for the duration of the Contract the following minimum amounts of insurance:

(a) Commercial general liability insurance or comprehensive general liability insurance with a minimum limit o[redacted]er occurrence for bodily injury 1
and damage to property including contractual liability, premises/operations, products/completed operations, independent contractors, broad form property damage, and personal injury coverage and a minimum aggregate amount of [redacted] or commercial/comprehensive general liability insurance plus 2
additional excess umbrella liability insurance to meet these limits.

(b) Comprehensive automobile liability insurance with a minimum combined single limit of[redacted]er accident for bodily injury and damage to property, or 3
covering bodily injuries or death in a sum not less than [redacted]per person and 4
[redacted]per accident and covering damages to property in a sum of at least 5
[redacted]per accident or comprehensive automobile liability insurance plus 6
[redacted] excess umbrella liability insurance to meet these limits. This insurance shall apply to any auto, whether owned or non-owned.

(c) Workers' compensation insurance as specified by state law in each state where work is to be performed; when workers' compensation is required, Contractor shall also provide employer's liability insurance in the minimum amount of[redacted] 7
each accident and [redacted]per employee for bodily injury by disease with a 8
disease policy aggregate of [redacted] or employer's liability insurance plus 9
additional excess umbrella liability insurance to meet these limits.

All such coverages shall be primary. Contractor agrees that it shall add Owner, its officers, employees, agents, and shareholders [and the North Carolina Eastern Municipal Power Agency (NCEMPA) for work performed at Roxboro Unit No. 4, Mayo Plant, Brunswick Nuclear Plant, and Harris Nuclear Plant] and all of Owner's parent, subsidiary, and affiliate companies to Contractor's liability insurance policies as additional insureds. Contractor shall require its insurance carrier or agent to certify that this requirement has been satisfied on all Insurance Certificates issued under this Contract.

Contractor waives and shall require its insurers providing the coverages specified above (excluding professional liability coverage, if required) to waive all rights of recovery against Owner, its officers, employees, agents, and shareholders [and the North Carolina Eastern Municipal Power Agency

(NCEMPA) for work performed at Roxboro Unit No. 4, Mayo Plant, Brunswick Nuclear Plant, and Harris Nuclear Plant] and all of Owner's parent, subsidiary, and affiliate companies. Contractor shall

require its insurance carrier or agent to certify that this requirement has been satisfied on all Insurance Certificates issued under this Contract.

Before any Work is initiated and before any invoices are paid for Work performed under this Contract, Contractor shall provide written proof of compliance with the above insurance requirements by delivering to:

Ms. Carol Shore
Progress Energy Service Company, LLC
P. O. Box 1551 (PEB 2C3)
Raleigh, NC 27602

a copy of certificate of insurance completed by his insurance carrier or agent certifying that minimum insurance coverages as required above are in effect and that the coverage will not be canceled or changed until thirty (30) days after written notice is given Owner. Contractor shall maintain, update, and renew the Certificate for the duration of the Contract. No payment will be made to Contractor prior to receipt by Owner of an acceptable Certificate of Insurance. In the event an acceptable Certificate of Insurance becomes outdated, Owner may elect to withhold payment of invoices, suspend Work or take other appropriate action until an acceptable and properly dated Certificate is received by Owner.

SECTION 21. INDEMNITY

To the maximum extent permitted by applicable law, each party (an "Indemnitor") shall indemnify, defend, and hold harmless the other party (including its parent, subsidiary and affiliate companies), its officers, employees, agents, and with respect to Owner, any other party with an ownership interest in the premises where the Work is to be performed (each an "Indemnitee"), from and against all liability, loss, costs, claims, damages, expenses, judgments, and awards, whether or not covered by insurance, to the extent arising:

(a) from negligent acts or omissions of Indemnitor which resulted in:

(1) injury to (including mental or emotional) or death of any person, including employees of Indemnitee (including its parent, subsidiary and affiliate companies), or

(2) damage to or destruction of any property, real or personal, including without limitation property of Indemnitee (including its parent, subsidiary and affiliate companies) and its other contractors, Indemnitee's (including its parent, subsidiary and affiliate companies') employees;

(b) from demands, actions or disputes asserted by any subcontractors, employees or suppliers of Indemnitor.

Indemnification shall include all costs including attorney's fees reasonably incurred in pursuing indemnity claims under or enforcement of this Contract.

To the maximum extent permitted by applicable law, Contractor shall indemnify and defend Owner (including its parent, subsidiary and affiliate companies), its officers, employees, agents, and any other party with an ownership interest in the premises, from and against all liability, loss, costs, claims, damages, expenses, judgments, and awards, whether or not covered by insurance, arising or claimed to have arisen:

> out of injuries sustained and/or occupational diseases contracted by Contractor's, subcontractor's, or assignee's employees, if any, of such a nature and arising under such circumstances as to create liability by Owner (or its parent, subsidiary or affiliate companies) or Contractor under the Workers' Compensation Act, and all amendments thereto, of the state having jurisdiction, including all claims and causes of action of any character against Owner (and its parent, subsidiary and affiliate companies) by any employee of Contractor, its subcontractors or assignees, or the employer of such employees, or any person or concern claiming by, under or through them resulting from or in any manner growing out of such injuries or occupational diseases; and

Indemnification shall include all costs including attorney's fees reasonably incurred in pursuing indemnity claims under or enforcement of this Contract.

SECTION 22. SECURITY

Contractor and its employees who perform work at any Owner property shall comply and follow Owner's environmental procedures, management of change procedures, and general operating procedures. Contractor shall advise its employees of these practices and procedures and secure their consent to abide by the procedures in a form satisfactory to Owner. Owner will provide a copy of these practices and procedures to Contractor under separate cover. Contractor shall review all procedures against current practices to ensure compliance.

SECTION 23. FITNESS-FOR-DUTY POLICY

Contractor acknowledges its awareness of Owner's contract personnel Fitness-For-Duty Program (FFDP) Drug and Alcohol Abuse Policy, which is as follows:

> The use, possession, or sale of narcotics, hallucinogens, depressants, stimulants, marijuana, or other controlled substances on Owner Property or while in pursuit of Owner business is prohibited. (This does not apply to medication prescribed by a licensed physician and taken in accordance with such prescription.) Unauthorized consumption of alcohol on Owner Property is also prohibited. The use of the above substances or alcohol on or away from Owner Property which adversely affects the employee's job performance, or may reflect unfavorably on public or governmental confidence in the manner in which Owner carries out its responsibilities, as determined by Owner, is also prohibited.

The term "Owner Property" includes any property or facility owned, leased, or under control of Progress Energy, Inc. or any of its subsidiaries, wherever located, including land, buildings, structures, installations, boats, planes, helicopters, and other vehicles.

SECTION 24. LAWS AND PROJECT RULES

A. General

Contractor and its subcontractors, if any, shall observe and abide by all applicable laws, federal, state and local, and the rules and regulations of any lawful regulatory body acting thereunder in connection with the Work. Without limiting the foregoing, Contractor agrees to comply with applicable provisions of the Americans with Disabilities Act, Fair Labor Standards Act of 1938, the Occupational

Safety and Health Act of 1970, Executive Order No. 11246, the Rehabilitation Act of 1973, the Vietnam Veterans Readjustment Act of 1974, as amended, and their respective implementing regulations, which are made a part hereof as if set out herein. Contractor warrants that it will meet the legal requirements of the Immigration Reform and Control Act of 1986, including, but not limited to, verifying workers' eligibility for U.S. employment through the completion of an I-9 form. Contractor and its subcontractors, if any, shall also comply with all applicable Owner health, safety and security rules, programs or procedures.

To the extent applicable, during the performance of this Contract, the contractor agrees as follows as it pertains to this Work and Contract: :

(1) The Contractor will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin. The Contractor will take affirmative action to ensure that applicants are employed, and that employees are treated during employment, without regard to their race, color, religion, sex, or national origin. Such action shall include, but not be limited to the following: Employment, upgrading, demotion, or transfer, recruitment or recruitment advertising; layoff or termination; rates of pay or other forms of compensation; and selection for training, including apprenticeship. The Contractor agrees to post in conspicuous places, available to employees and applicants for employment, notices to be provided by the contracting officer setting forth the provisions of this nondiscrimination clause.

(2) The Contractor will, in all solicitations or advertisements for employees placed by or on behalf of the Contractor, state that all qualified applicants will receive consideration for employment without regard to race, color, religion, sex, or national origin.

(3) The Contractor will send to each labor union or representative of workers with which he has a collective bargaining agreement or other contract or understanding, a notice to be provided by the agency contracting officer, advising the labor union or workers' representative of the Contractor's commitments under section 202 of Executive Order 11246 of September 24, 1965, and shall post copies of the notice in conspicuous places available to employees and applicants for employment.

(4) The Contractor will comply with all provisions of Executive Order 11246 of September 24, 1965, and of the rules, regulations, and relevant orders of the Secretary of Labor.

(5) The Contractor will furnish all information and reports required by Executive Order 11246 of September 24, 1965, and by the rules, regulations, and orders of the Secretary of Labor, or pursuant thereto, and will permit access to his books, records, and accounts by the contracting agency and the Secretary of Labor for purposes of investigation to ascertain compliance with such rules, regulations, and orders.

(6) In the event of the Contractor's non-compliance with the nondiscrimination clauses of this Contract or with any of such rules, regulations, or orders, this Contract may be canceled, terminated or suspended in whole or in part and the Contractor may be declared ineligible for further Government contracts in accordance with procedures authorized in Executive Order 11246 of September 24, 1965, and such other sanctions may be imposed and remedies invoked as provided in Executive Order 11246 of September 24, 1965, or by rule, regulation, or order of the Secretary of Labor, or as otherwise provided by law.

(7) the Contractor will include the provisions of paragraphs (1) through (7) in every subcontract or purchase order unless exempted by rules, regulations, or orders of the Secretary of Labor issued pursuant to section 204 of Executive Order 11246 of September 24, 1965, so that such provisions will be binding upon each subcontractor or vendor. The Contractor will take such action with respect to any subcontract or purchase order as may be directed by the Secretary of Labor as a means of enforcing such provisions including sanctions for noncompliance: Provided, however, that in the event the Contractor becomes involved in, or is threatened with, litigation with a subcontractor or vendor as a result of such direction, the Contractor may request the United States to enter into such litigation to protect the interests of the United States.

Contractor shall indemnify and hold Owner (or its parent, subsidiary or affiliate companies) and its plant co-owners harmless with respect to any claims, expenses (including reasonable attorney's fees), liability or damages arising out of Contractor's failure to comply with any applicable laws, rules, or regulations, or any Owner rules, programs, or procedures.

Work performed and materials and equipment provided by Contractor shall conform to and comply with all the applicable federal, state, and municipal laws, rules, and regulations concerning occupational health and safety, including, but not limited to, the Occupational Safety and Health act of 1970 and the regulations and standards issued thereunder (hereinafter "OSHA requirements"). Contractor warrants that any work performed in a location partially or entirely under Contractor's control shall be performed in accordance with "OSHA Requirements". Contractor further warrants that all materials and equipment furnished by Contractor shall conform to and comply with all applicable provisions of "OSHA requirements" and the regulations and standards issued thereunder, specifically those (designed to accept a lockout device, machine guards in place, etc.) Contractor shall require these warranties of adherence to "OSHA requirements" from each subcontractor and supplier it employs. Contractor shall indemnify and hold harmless Owner (including its parent, subsidiary and affiliate companies) from all damages suffered by Owner (including its parent, subsidiary and affiliate companies) (including damages to third parties) as a result of the failure of Contractor or any of its subcontractors or suppliers to comply with "OSHA requirements" and for the failure of any of the materials or equipment furnished to so comply.

Contractor shall fully comply with all export and import control laws and regulations with regard to any Work performed by Contractor or with regard to information supplied by Owner to Contractor under this Agreement. In particular, Contractor shall not directly or indirectly use, export, re-export, distribute, transfer or transmit any such Work or information in whole or in part, in any form without all required United States and foreign government licenses and authorizations, including but not limited to any applicable export controls of the U.S. Nuclear Regulatory Commission, the U.S. Department of Energy or the U.S. Department of Commerce. In no event shall Owner be obligated under this Contract or any other agreement to provide access to or furnish any Work or information except in compliance with applicable United States export control laws, regulations, policies, licenses and approvals.

To the extent and in the amount the purchase price of any materials is paid by Owner to Contractor prior to delivery, Owner shall obtain a lien on the material. Such lien shall be fully enforceable and of the highest priority allowed by law. Complete legal and equitable title to all such material and risk of loss or damage to the material shall pass to Owner upon delivery F.O.B carrier at destination, whether full or partial payments are made before or after delivery at destination or whether payments are withheld pending supplemental inspections and/or tests by Owner at the destination so as to establish full compliance with this Contract and any applicable specifications. Nothing in this Section shall be construed as releasing or waiving any responsibility of the Contractor either under this Contract or at law.

Whenever any property of Owner is sent to Contractor's premises for repair, refurbishment, or any other purpose, title to such property shall at all times remain with Owner. Contractor shall clearly mark such property to show that it is owned by Owner and shall keep all such property separate from Contractor's own property and the property of any third parties. Contractor's interest in such property shall be only that of a bailee, and such property shall not be subject to any lien, security interest or other claim asserted by any creditor of Contractor. Contractor shall bear the risk of loss or damage to such property while it is on Contractor's premises; and Contractor shall also bear the risk of loss or damage to the property while it is in transit between Owner's premises and Contractor's premises when the arrangements for transportation of the property have been made by Contractor rather than Owner.

Should compliance with any laws, rules, regulations, or ordinances of any federal, state, or local authority, or of any agency thereof (including, but not limited to, certification to do business as a foreign corporation) require any changes in the Work or should any permits, licenses, or approvals of plans and specifications for the Work and any additional Work or any permits, licenses, or approvals for the installation or use thereof be required, Contractor assumes the risk and responsibility for such compliance or change, or for securing such permits, licenses, and approvals from the proper authorities, and for paying any associated costs or fees.

Notices

All notices or official communications required to be given hereunder shall be in writing by either party and shall be deemed sufficient when mailed by United States certified mail, return receipt requested, or hand delivered to Owner's Designated Representative (if to Owner) at the addresses set forth herein or by recognized overnight delivery service, to the address initially set forth in the Contract. All notices shall be deemed delivered on the day they are hand-delivered to the other party or, if sent by overnight delivery service, two (2) days after tendered to such service.

Either party may change its address for the receipt of notices, requests or other communications hereunder by written notice duly given to the other party. This change shall be made by Amendment.

The parties' obligation to provide written notice to each other may not be waived. Electronic or computerized mail is not an acceptable form of delivery of notices required by this Contract. The Parties expressly and unequivocally waive any claim against the other Party based upon actual, verbal, or constructive notices. All written notice requirements are to be strictly construed and are a nonwaivable condition precedent to pursuing any claims, rights, or remedies by Contractor under this Contract.

B. Employment Taxes and Contributions

Contractor assumes exclusive liability for all contributions, taxes or payments required to be made under the applicable federal and state Unemployment Compensation Act, Social Security Acts and all amendments, and by all other current or future acts, federal or state, requiring payment by the Contractor on account of the person hired, employed or paid by Contractor for Work performed under this Contract.

C. Drawings and Specifications

It is the intent of Owner to have all drawings and specifications for the Work comply with all applicable statutes, regulations, and ordinances. If Contractor discovers any discrepancy or conflict between the drawings and specifications and applicable legal requirements, Contractor shall immediately report the discrepancy in writing to Owner's Designated Representative.

D. Not Used

E. Environmental Provisions

1. Compliance with Environmental Laws

    a. In performing its obligations and other activities pursuant to this Contract, each party shall comply with all Environmental Laws.

    b. If a party encounters ACM and/or lead, such party shall immediately notify the Designated Representative. Contractor shall not Manage such ACM and/or lead without Owner's prior approval. Contractor shall perform any such Work in accordance with the acceptable industry standards and practices.

    c. Contractor may obtain from the Designated Representative any records and other information which the Designated Representative deems relevant to Contractor's compliance with Environmental Laws. Owner does not warrant the accuracy or completeness of such records and information, and Contractor shall determine independently how to conform its activities to the requirements of Environmental Laws.

2. Regulated Substances and Hazardous Chemicals

a. For purposes only of this Subsection 2., Owner Property means property Owner owns, leases and/or operates.

b. Prior to bringing any Regulated Substance (excluding Urea Liquor) onto Owner Property Contractor shall deliver to the Designated Representative: (1) notice of the Regulated Substance's identity and intended use, (2) notice of the length of time the Regulated Substance will be used on Owner Property and (3) a description of any wastes that will be generated as a result of using the Regulated Substance.

c. Prior to bringing onto Owner Property any Regulated Substance (excluding Urea Liquor), Contractor shall deliver to Owner a description of the potential for Owner employee exposure to the hazardous chemical, the hazardous chemical's brand name (including generic name and chemical abstract number [CAS#]), container volume or weight, number of containers, container pressure and temperature, physical state, storage location, estimated annual usage, manufacturer and material safety data sheet.

d. Contractor shall deliver to Owner for Management any hazardous waste which Contractor generates on Owner Property. Contractor shall not remove such hazardous waste from Owner Property.

e. Upon completion of the Work, Contractor shall remove all of Contractor's unused chemicals from Owner Property.

3. Releases

a. Contractor shall not Release any Regulated Substance on Owner Property, or on any roadways leading to or from Owner Property.

b. In the event Contractor Releases any material or substance on Owner Property, Contractor immediately shall notify the Designated Representative and remediate the Release pursuant to all applicable Environmental Laws and to Owner's direction and reasonable satisfaction. Owner's costs in supervising, directing, inspecting and/or assisting Contractor to respond to the Release shall be subject to Indemnification under Subsection 4. hereof.

c. If following a Release Contractor fails to comply with the terms of Subsection 3.b., Owner may in its discretion remediate the Release and otherwise perform Contractor's obligations. Owner's costs in performing Contractor's remedial activities shall be subject to Indemnification under Subsection (4) hereof.

4. Environmental Indemnity

a. For a period of six (6) months from the expiration or termination of the Contract, Contractor shall Indemnify Owner (or its parent, subsidiary or affiliate companies) from any Claim or loss in property value of Owner's Plant Property arising from Contractor's negligent Management of any Regulated Substance (collectively for this Section 24(E)(4)(a)-(d) only, hereinafter termed an "Action").

b. Owner agrees to give prompt notice to Contractor of the assertion or the commencement of any Action in respect of which indemnity may be sought under this Section 24(E)(4)(a) (specifying with reasonable particularity the basis therefor) and give Contractor such information with respect thereto as the Contractor may reasonably request. Contractor may, at Contractor's own expense, participate in and, upon notice to Owner, assume the defense of any such Action; provided that Contractor's counsel is reasonably satisfactory to Owner. Contractor shall thereafter consult with Owner, upon Owner's reasonable request, from time to time with respect to such Action, and Contractor shall not, without Owner's written consent, which consent shall not be unreasonably withheld, settle or compromise any such Action. If Contractor assumes such defense, Owner shall have the right (but not the duty) to participate in the defense thereof and to employ counsel, at its own expense, separate from the counsel employed by the Contractor. For any period during which Contractor has not assumed the defense thereof, Contractor shall be liable for the fees and expenses of counsel employed by any Owner; provided, however, that Contractor shall not be liable for the fees or expenses of more than one counsel employed by Owner. If Owner assumes the defense thereof, Owner shall thereafter consult with Contractor, upon Contractor's reasonable request, for such consultation from time to time with respect to such Action, and Owner shall not, without Contractor's written consent, which consent shall not be unreasonably withheld, settle or compromise any such Action. Whether or not Contractor chooses to defend or prosecute any Action, the parties hereto shall cooperate in the defense or prosecution thereof.

c. In evaluating all Actions, the parties shall mutually agree upon an independent third party whose purpose shall be to assess the extent of any Action and submit his/her findings to the parties to be used as a data point in assessing the extent of any Action. In the event the parties are unable to reasonably agree upon the independent third party within thirty (30) days following an Action, the parties agree that no independent third party evaluation shall be necessary.

d. The limitations in this Section 24(e) (4) (a)-(c) shall in no way limit Contractor's indemnification obligations elsewhere in this Contract.

5. Environmental Audits

Owner shall have the right to conduct an on-site environmental review of any of the Contractor's or its subcontractor's or supplier's facilities at any time to verify compliance with federal, state and local statutes, regulations and ordinances. Contractor shall ensure that Owner shall have the right to conduct on-site environmental audits of any subcontractor's facilities to verify compliance with all federal, state and local statutes.

6. Definitions

The definitions below only are applicable to this Environmental Provisions Section.

a. ACM or Asbestos-Containing Material means (a) friable asbestos material, (b) Category I nonfriable ACM (as defined in 40 C.F.R. §61 (Subpart M)) that has become friable, (c) Category I nonfriable ACM that will be or has been subjected to sanding, grinding, cutting or abrading or (d) Category II nonfriable ACM (as defined in Subpart M) that has a high probability of becoming or has become crumbled, pulverized or reduced to powder by the forces expected to act on the material in the course of demolition or renovation operations.

b. Claim means any (1) administrative, regulatory or judicial action or cause of action, suit, liability, judgment, penalty, damages, directive, order, claim relating in any way to any Environmental Law, the Management of any Regulated Substance, the presence of any Regulated Substance in the environment or any alleged injury or threat of injury to health, safety, property or the environment and (2) cost or expense (including, without limitation, any attorneys', experts' and consultants fees' and expenses) which is or may be necessary, in Owner's reasonable judgment , to comply with any Environmental Law, to respond to and defend against any action listed in clause (1), to protect the health or safety of any person or to permit or facilitate any lawful use of real property.

c. Owner Property means any property, facility or equipment owned, leased or under the control of Owner or Contractor wherever located, including land, buildings, structures, installation, boats, planes, helicopters and other vehicles.

d. Environmental Law means any federal, state or local law, statute, ordinance, rule, guideline, judicial or administrative order or other public authority now in effect or hereafter enacted relating to (1) the regulation or protection of human health, safety, occupational safety and health, the environment or natural resources or (2) any Regulated Substance.

e. Indemnify, with respect to any Claim or cost, means (1) to indemnify, save and hold harmless, reimburse and make whole on an after-tax basis, the designated indemnitee and its affiliates and their respective officers, directors, employees, partners and agents from any Claim or cost imposed on or incurred by the indemnitee, or asserted by any third party against the indemnitee; (2) to defend any suit or other action brought against the indemnitee on account of any Claim and (3) to pay any judgment against, and satisfy any equitable or other requirement imposed on, the indemnitee resulting from any such suit or action, along with all costs and expenses relative to any such Claim, including, without limitation, reasonable attorney's, consultant's and expert witness fees and public relations costs.

f. Manage or Management, with respect to any substance or material, means the manufacture, processing, distribution, use, possession, generation, transportation, labeling, identification, handling, removal, treatment, storage, disposal, Release or threatened Release thereof.

g. Regulated Substance means any chemical, material, substance or waste the exposure to, access to or Management of which is now or hereafter prohibited, limited or regulated by any law or governmental unit. Regulated Substances include without limitation ACM and Lead.

h. Release(s), with respect to any substance or material, means any spilling, leaking, pumping, emitting, emptying, discharging, injecting, escaping, leaching, dumping or disposing of such substance into the environment, or any other act or event the occurrence of which would require containment, remediation, notification or similar response under any law.

i. Urea Liquor means a solution of urea in water of various concentrations but typically ranging from 40 to 70 weight percent urea.

F. Federal Subcontracting Requirements:

1. The provisions of the following Laws, Executive Orders, and any rules and regulations issued thereunder, are incorporated herein by reference as part of this Contract to the extent applicable to the Work and this Contract..

    - Provisions of the Utilization of Small Business Concerns clause set forth at Section 52.219-8 of the Federal Acquisition Regulations, Title 48 of the Code of Federal Regulations
    - Provisions of the Small Business Subcontracting Plan clause set forth at Section 52.219-9 of the Federal Acquisition Regulations, Title 48 of the Code of Federal Regulations.

2. The Contractor agrees to fully comply with such provisions and any amendments thereof. In addition, all subcontracts and agreements that the Contractor enters into to accomplish the Work under the terms of this Contract shall obligate such subcontractors to comply with such provisions.

3. Compliance with the above provisions involve the development of a subcontracting plan, as prescribed in 19.704 of the Federal Acquisition Regulations, herein incorporated by reference. The attached Supplier Diversity and Business Development Subcontracting Report shall be used to report awards to small business concerns under the subcontracting plan.

SECTION 25. SEVERABILITY

If any term or provision of this Contract is held illegal or unenforceable by a court with jurisdiction over the Contract, all other terms in this Contract will remain in full force, the illegal or unenforceable provision shall be deemed struck. In the event that the stricken provision materially affects the rights, obligations or duties of either party, Owner and Contractor shall substitute a provision by mutual agreement that preserves the original intent of the parties as closely as possible under applicable law.

SECTION 26. GOVERNING LAW

This Contract shall be governed by the laws of the State of North Carolina, except that the North Carolina conflict-of-law provisions shall not be invoked in order to apply the laws of any other state or jurisdiction. Owner and Contractor expressly waive their rights to a trial by jury in any action brought hereunder.

SECTION 27. CONFIDENTIALITY; USE OF INFORMATION

The terms of this Contract and all Amendments to it are to remain confidential and shall not be provided in any form to any other party except upon order of a regulatory body or a court of competent jurisdiction. Neither party shall make any public statements or publish any information related to the Work performed or to be performed under this Contract without the prior written consent of Owner.

Materials which are reviewed by either party in the course of this Contract may contain trade secrets which are the property of the other or which have been loaned, licensed, purchased or leased for use. Neither party shall reveal any trade secret material to any person in any form and further agrees not to use the material for itself for any purpose not connected with this Contract.

Contractor agrees that if access is granted to Owner's computer network or a segment thereof, that this access is solely for the business purpose(s) described in Section 1 of this Contract. Contractor agrees that access for any other purpose or the use of Owner's computer network to access other networks, is strictly forbidden and that Contractor is responsible and liable for all damages or unauthorized access resulting from these actions. This activity will result in the discontinuation of any and all network connections, and Contractor understands that it may be subject to civil and/or criminal prosecution. Contractor further agrees that any information that it obtains from Owner's computer network is subject to all of the terms and conditions of this Contract.

SECTION 28. PUBLIC COMMUNICATION

Contractor agrees to cooperate with Owner in maintaining good community relations. Owner will issue all public statements, press releases, and similar publicity concerning the Work, its progress, completion, and characteristics. Contractor shall not make or assist anyone to make any such statements, releases, photographs, or publicity without prior written approval of Owner.

SECTION 29. NONWAIVER

Owner's failure to insist on performance of any of the terms and conditions herein or to exercise any right or privilege or Owner's waiver of any breach hereunder shall not thereafter waive any of Owner's rights or privileges under this Contract or at law. Any waiver of any specific breach shall be effective only if given expressly by Owner in writing.

SECTION 30. MERGER

This Contract embodies the entire agreement between Owner and Contractor. The parties shall not be bound by or liable for any statement, writing, representation, promise, inducement or understanding not set forth above. No changes, modifications or amendments of any terms and conditions of this Contract are valid or binding unless agreed to by the parties in writing and signed by their authorized agents.

Each party to this agreement and its counsel have participated in the creation of this agreement. The normal rule of construction to the effect that ambiguities are to be resolved against the drafting party shall not be employed in the interpretation of this agreement or of any amendments or exhibits to this agreement.

SECTION 31. BACKGROUND INVESTIGATION AND DRUG SCREEN

NOTE: The requirements of this Section do not apply to nuclear protected/vital area access.

In order for Owner to confirm Contractor's compliance with the Background Investigation/Drug Screen requirements in this Contract, Contractor is required to complete the Background Investigation/Drug Screen Compliance Plan attached. This Plan identifies the points of contact within Contractor's organization and other information for Owner to use in verifying Contractor's compliance.

Should any information on the Compliance Plan change during the term of the Contract, Contractor shall notify Owner's Designated Representative in writing within thirty (30) days of the change.

Contractor shall conduct a Background Investigation ("BI") and pre-assignment Drug Screen ("DS") as described below for all Contractor's employees and/or Contractor's subcontractor employees where the scope of work to be performed will require: (i) a presence for a single period of 15 calendar days or more upon property owned or leased by Owner (except right-of ways) or any of Owner's subsidiaries or affiliates and/or (ii) access to Owner's business critical infrastructure and/or (iii) security badge access to Owner facilities. In addition, BI/DS requirements may be applied to other personnel at the sole discretion of Owner's Designated Representative. Owner shall reimburse Contractor in accordance with Paragraph E of this Section for each Contractor employee and subcontractor employee for whom an approved provider performs full or updated BIs and DSs, unless Work is performed on a firm fixed price basis. Owner shall not be obligated to reimburse Contractor for any BI or DS expense for any Contractor employee or subcontractor employee who fails to meet the minimum acceptable qualifications. The BIs and DSs must be performed by service providers approved by Owner as acceptable to conduct BIs and DSs (the "Approved BI and DS Providers"). Paragraph E of this Section lists the Approved BI and DS Providers.

Contractor shall obtain a release from each of its employees and subcontractor employees that will perform Work under the terms of this Contract that allows Owner to access the BI and DS records from the Approved BI and DS Provider's web enabled access systems or through other methods agreeable to Owner. Owner will access these records only for the purpose of conducting periodic audits to ensure compliance with the conditions herein, and for the purpose of audit required by a governmental agency. In instances in which an employee or any subcontractor employee of Contractor is granted access to a facility or property that is covered within the scope of the North American Electric Reliability Corporation Critical Infrastructure Protection (NERC CIP) regulations, 18 CFR 39, or the Chemical Facility Antiterrorism Act (CFATS) regulations, 6 CFR 27, Contractor agrees to permit Owner to obtain and maintain a copy of the BI and DS of each Contractor employee or subcontractor employee in order for Owner to demonstrate access eligibility and compliance with the NERC CIP and CFATS regulations.

In the event Contractor uses a BI and/or DS provider or process that is not pre-approved by Owner, Contractor is required to submit its BI and DS program to Owner for review and approval. Contractor agrees to permit Owner to obtain copies of the BI result information when needed for regulatory reasons, and to audit the BI result information as necessary to establish Contract compliance.

Contractor agrees to maintain BI records for a minimum of seven (7) years after the Work is completed.

Contractor is solely responsible for ensuring that Contractor's employees and any subcontractor employees assigned to the Work meet or exceed the requirements of this Section. Contractor must have all BIs and DSs completed prior to the start of Work. In the case of emergencies, Contractor may be permitted to start Work while the BIs or DSs are being conducted. (If an emergent need requires delay in processing, Owner approval is required, and all BIs and DSs must be completed within 10 working days of the start date).

A. Responsibilities

Contractor shall be responsible to:

1. Comply with the legal requirements of the Immigration Reform and Control Act of 1986, including, but not limited to, verifying its employees' and ensuring its subcontractors verify their employees' eligibility for U.S. employment through the completion of an I-9 form for each employee or subcontractor employee. Documentation of I-9 form completion will be maintained by the Contractor

and made available to Owner upon request. Contractor is the employer and makes decisions regarding assignments.

2. Initiate and ensure the completion of the appropriate BIs. Contractor's employees and Contractor's subcontractor employees should be required to complete a background questionnaire or employment application which includes additional names used by applicant, history of residences and criminal history. Contractor is the employer and makes decisions regarding assignments based on these guidelines.

3. Notify its employees and any subcontractor employees of the terms and conditions of the BI and DS and requirements of this Contract.

4. Furnish Owner with any Contractor employees and subcontractor employees who meet or exceed the requirements of the BI and DS and the terms and conditions of the Contract.

5. Obtain written permission for the release to Owner of its employees' and any subcontractor employees' personal history information and information contained in the BI report and DS.

6. Require its employees and subcontractors to report any arrest and evaluate under the Rejection Criteria to determine if Contractor's employee or any subcontractor employee meets Owner's criteria for rejection. (All Contractor employees and any of its subcontractor employees who meet the Rejection Criteria must be removed from Owner's Work immediately.)

7. Abide by the Fair Credit Reporting Act (FCRA) requirements and all other applicable state and federal laws regarding BIs and DSs, and consent to release information.

<u>B. Types and Components of Background Investigation</u>

<u>1. Full Background Investigation</u>

a. Social Security Number/Name/Address Validation

Contractor shall verify the Social Security Number (SSN), name, date of birth and/or addresses of its employees, and ensure its subcontractors verify the same of their employees, from sources such as an SSN trace report available through credit databases. Contractor agrees to perform, and ensure its subcontractors perform, additional criminal history checks for names and addresses that appear on the SSN report within the past seven (7) years and cannot be attributed to a spouse's surname or typographical error. Contractor, and its subcontractors, shall resolve any discrepancies discovered, including multiple SSNs that do not appear to be typographical in nature, fraud alerts, and any address associated with Correctional, Hospital or Clinical Institutions. Contractor shall verify its employees', and ensure its subcontractors verify its employees', SSNs through the Social Security Administration.

b. Criminal Record

Prior to Contractor's employee or subcontractor employee performing Work, Contractor shall conduct a criminal history record check covering the previous seven years, or to age 18, in each state/locality where Contractor's employee has resided, including addresses within the past seven years identified on the SSN Trace Report, or where Contractor's employee disclosed criminal history on the background questionnaire. Contractor shall take action to ensure its subcontractors conduct the same criminal history record check and comply with the requirements listed in this subsection for each of its employees.

Record checks should be conducted by contacting the appropriate agency of record such as state law enforcement agency, state criminal record repositories (normally statewide repositories should only be used for states such as New York and North Carolina, unless otherwise approved), local law enforcement agencies, state and local courts. Contractor shall ensure record repositories hold complete criminal history information (pending cases, misdemeanor records, and felony records, etc).

Reported criminal records should include specific offense information, court and jurisdiction and disposition of charge.

c. Terrorist Watch List Search (Patriot Act)

Contractor shall conduct a Terrorist Watch List search through the U. S Office of Foreign Asset Control on Contractor's employees and subcontractors employees intended to perform Work. The search shall include a check of whether the employee or subcontractor employee is a Designated National or Blocked Person, as defined by the U. S Office of Foreign Asset Control.

1. Drug Screen

Contractor shall conduct a DS as defined in this Section.

2. Updated Background Investigation

An updated BI is acceptable for Contractor's re-hired employees or subcontractors' employees if the employee or subcontractor employee previously had a full BI and DS completed that meets Owner's criteria described in this Section and it was completed by the current Contractor within the past three years of current effective Work start date. The following components shall be checked:

1. Criminal history checks in the county or counties where Contractor's employee or subcontractor employee has resided, including addresses on the SSN Trace Report since the last seven year check was performed.
2. Terrorist Watch List search
3. DS

C. Rejection Criteria to Disqualify Candidates for Assignment

The decision by Contractor to disqualify an employee or subcontractor employee for assignment shall be based upon consideration of all relevant information, favorable and unfavorable, as to whether the assignment would be clearly consistent with the necessity to maintain an environment conducive to a safe work place.

To assist in making appropriate determinations, this matrix identifies several types of adverse information. These are not all-inclusive, but contain many of the factors, which may raise legitimate questions to a Contractor's employee's or subcontractor employee's eligibility for assignment. Contractor is the employer and makes decisions regarding assignments based on these general guidelines.

1. Criminal Charges

a. Criminal Charges Pending

"Pending" is defined as awaiting formal review by the court to determine the disposition of the arrest. All pending charges will be evaluated on a case by case basis; however pending charges which may meet Owner's criteria for disqualification if convicted will normally preclude an acceptable recommendation.

Charges which result in a disposition of adjudication withheld, nolle pross, pre-trial intervention, prayer for judgment continued or are otherwise unadjudicated shall be evaluated on a case by case basis. This evaluation shall focus on the status of the charge, and the behavior or incident which resulted in the charge being made, and the effect on an applicant's trustworthiness and reliability.

b. Felony Convictions

CRITERIA FOR REJECTION	ACTIONS TO BE CONSIDERED
Any felony conviction with in the last five years	Not eligible for assignment for five years from the date of conviction.
Persons currently on active probation/parole or a work furlough program for a felony conviction or participating in court diversion program for charges which would meet rejection criteria. (Ex. Pre-trial intervention and deferred prosecution).	Not eligible for assignment until completion of probation or parole or court diversion program. Eligibility must also comply with criteria above. (As if convicted)
Failure to fulfill a court order (i.e. failure to appear) for any felony conviction.	Not eligible for assignment until disposition of court order is completed.

c. Misdemeanor Convictions

CRITERIA FOR REJECTION	ACTIONS TO BE CONSIDERED
Any misdemeanor conviction within the last five years involving illegal drugs (includes individuals currently serving a court-ordered diversion program)	Not eligible for assignment for five years from date of last conviction.
Any misdemeanor conviction within the last year involving violence or theft.	Not eligible for assignment for one year from the date of conviction.
Three or more misdemeanor convictions involving alcohol, violence or theft within the last five years. For example, convictions in 11/2005, and 11/2006 and 6/2007 not eligible until 11/2010	Not eligible for assignment for five years from the date of earliest conviction.
Persons on active probation/parole or a work furlough program for a misdemeanor conviction or participating in court diversion program for charges which would meet rejection criteria. (Ex. Pre-trial intervention and deferred prosecution).	Not eligible for assignment until completion of probation or parole or court diversion program. Eligibility must also comply with criteria above. (As if convicted)
Multiple misdemeanor convictions; including, but not limited to acts of violence, alcohol, and theft that demonstrate a pattern of continued disregard for the laws of the land and adversely reflects on the person's reliability and trustworthiness.	Contractor shall exercise reasonable discretion to determine appropriate action on a case by case basis.
Failure to fulfill a court order (i.e. failure to appear) for any misdemeanor conviction	Assignment may not be recommended based on the severity of the court order.

d. Other

CRITERIA FOR REJECTION	ACTIONS TO BE CONSIDERED
One drug test failure	Not eligible for assignment for 5 years.
Evidence or admission of use, possession or sale of illegal substances	Not eligible for assignment for 5 years from the most recent occurrence.
The refusal to participate in drug testing	Not eligible for assignment.
Attempted to subvert the testing process, or has shown in	Not eligible for assignment for 5 years.

anyway to have altered a specimen provided for testing	
Any other information that would adversely reflect upon the reliability and trustworthiness of the person as it relates to their assignment to Owner	Not eligible for assignment – eligible to reapply determined on a case by case basis.
Prior termination due to a Progress Energy Code of Ethics Violation	Not eligible for assignment.
Information regarding denial at any of Owner's nuclear facilities.	Employment may not be recommended based on the reason for denial.
Social Security Number not verified by Social Security Administration	Not eligible for assignment until verification of Social Security Number is validated.

D. Drug Screen

All of Contractor's employees and subcontractors' employees who will require a BI will also be required to have a DS. Contractor must have all DSs completed prior to the start of Work. In the case of emergencies, Contractor may be permitted to start Work while the DSs are being conducted. (All DSs must be completed within 10 working days of starting work.)

A certified Health and Human Services Laboratory must perform all DSs. Only Contractor employees and subcontractor employees whose test result is determined to be negative are eligible to work on Owner controlled property. In addition, Contractor employees and subcontractor employees who refuse to participate in DSs, attempt to subvert the DS testing process, or are shown in any way to have altered a specimen provided for any DS are not eligible to work under this Contract.

Owner shall not be obligated to reimburse Contractor for any DS expense for Contractor employees or subcontractor employees who fail to meet the minimum acceptable qualifications.

The screening for the substances below and the testing levels generally follow the Department of Transportation Guidelines. Laboratories that use lower cut off levels for drugs or Metabolite than those listed below are acceptable by Owner.

1. Drug Screen Cut Off Concentrations for Screening and Confirmation Levels

Type of Drug or Metabolite	Initial Test	Confirmation Test
Marijuana Metabolites	50	15
Cocaine Metabolites (Benzoylecgonine)	300	150
Phencyclidine (PCP)	25	25
Amphetamines	1000	
Amphetamine		500
Methamphetamine		500 (specimen must also contain amphetamine at a concentration of greater than or equal to 200 ng/ml.)
Opiate metabolites	2000	
Codeine		2000
Morphine		2000
6-monacetylmorphine (6-MAM)		10 (Test for 6-MAM in the specimen. Conduct this test only when specimen contains morphine at a concentration greater than or equal to 2000 ng/ml.)

2. Specimen Collection

The specimen must be collected by trained and qualified collectors and collected under conditions that protect the integrity of the specimen. Laboratory patient service centers and Doctor's Urgent Care are suggested for collection purposes.

E. Approved Background Investigation and Drug Screening Providers

1. Sterling Testing Systems
   Attn: Lance Zacker
   Regional Director of Sales

   Phone: 212-812-1045
   Fax: 646-435-2273
   E-Mail: Lzacker@sterlingtesting.com
   www.sterlingtesting.com

2. A-Check America, Inc.
   Attn: Alanna Flores

   Phone: 877-345-2021 ext. 3085
   Fax: 951-750-1667
   E-Mail: aflores@acheckamerica.com
   progressenergy@ acheckamerica.com
   www.acheckamerica.com

BI/DS Pricing:
The providers listed above have pre-established pricing with Owner for performing a BI/DS. Owner reimbursements will be at the pre-established rates. If Contractor chooses to use a provider not listed above, reimbursements will be capped by the rates charged by the above providers. The cost for performing a BI/DS is currently capped at $55.00. This amount is subject to increase only if the pre-established rates increase for the above providers. Criminal Searches within the 7 year time frame required outside of the United States will be reimbursed as pass-through expenses at reasonable and customary costs.

SECTION 32. WORKPLACE VIOLENCE PREVENTION

Owner strives to provide a workplace for a worker that is free from physical attack, threats of violence and menacing or harassing behaviors.

Owner will not tolerate any unwanted or hostile physical contact, including physical attack, threat of violence, harassment, or damage of property by or against any worker including Owner employees.

Any worker who experiences, witnesses, or has knowledge of acts, conduct, behavior, or communication (threat) that may constitute or may lead to a workplace violence event should immediately report the incident to any of the following:

1. Contractor Supervisor or Owner supervisor or manager, AND
2. Corporate Security 1-888-275-4357 or
3. The Ethics Line at 1-866-8Ethics (1-866-838-4427)

SECTION 33. ELECTRONIC TRANSMITTALS

Owner and Contractor acknowledge that documents requiring signatures may be transmitted electronically. Owner and Contractor stipulate that if this contract is transmitted electronically, the electronic transmittal of the original execution signatures shall be treated as original signatures and given the same legal effect as an original signature.

- Next paragraph begins on following page -

The parties execute this Contract by their signature or the signature of their authorized agents.

TERRA ENVIRONMENTAL TECHNOLOGIES INC.	PROGRESS ENERGY SERVICE COMPANY, LLC. not in its individual capacity, but solely as agent for PROGRESS ENERGY FLORIDA, INC.
BY: Joseph D. Bisch	BY: Helen H. Green
NAME (printed): Joseph D. Bricker	NAME: Helen H. Green
TITLE: Vice President	TITLE: Senior Sourcing Specialist
DATE: 3/16/09	DATE: March 12, 2009

Should the person's title who is executing this document not indicate that he/she is a corporate officer, an affidavit signed by a corporate officer shall be provided stating that the person whose name appears above is duly authorized to execute Contracts on behalf of the firm.

Indicate your Social Security Number OR your Federal Tax Identification Number (FTIN). This number shall correspond with the Contractor name indicated above and shall be the same Federal Tax Identification Number under which you report income. **COMPLETE ONLY ONE.**

Federal Tax ID # 761586884	Social Security # [redacted]

The Internal Revenue Service (IRS) requires us to obtain certain information from you to meet IRS Form 1099 reporting and filing requirements. If you do not provide your correct FTIN, your payments may be subject to 20% backup withholding. Under penalties of perjury, I certify that the FTIN shown above is correct for the Contractor named.

R Mull... - Director TET Logistics

(Contractor to fill in name and title)

is appointed as the person to whom all official correspondence to Contractor concerning this Contract should be directed.

In accordance with the Federal Acquisition Regulation section 52.219, please check all that apply to your company. Please provide supporting documentation or certification to confirm the status for any categories checked under Small/Diverse Vendors.

[ ] Certified small business*
[ ] Veteran-owned business*
[ ] Service-disabled veteran-owned business*
[ ] Not a Small Business
[ ] HUBZone, 8(a) or disadvantaged business*
[ ] Minority-owned business * *
[ ] Women-owned small business * *

* As defined by the Small Business Administration (SBA): www.sba.gov
* * Certified by Progress Energy and as defined by SBA.

Register online at www.progress-energy.com/supplierdiversity

One-Time Non-Nuclear
Revision 09/09/2008
#5391

PEF-POD4-00114

Attachment A

1. WORK

   a. The Work. The Contractor agrees to provide the services listed in detail on Exhibit A (the "Work") at the Crystal River Units 4 & 5 Facility Terminal, subject to the Contractor or its Affiliate being the sole supplier of Product to the Owner. In the event that the Sales Agreement or any similar agreement terminates or expires for any reason, the Contractor shall have the right to terminate this Attachment upon thirty (30) days written notice to the Owner. The Work shall be performed in accordance with Good Industry Practice.

   b. Terminal Management. The Contractor shall operate the Terminal in accordance with the Work and, at all times, have sole authority with respect to all personnel matters involving the Representatives of the Contractor at the Terminal, including salaries, benefits, compensation, indirect personnel costs, training, insurance, labor matters, working hours, job responsibilities, health and safety procedures, bonding and all other employee, personnel-related and contracting matters. The Contractor shall be responsible for coordinating the provision of the Work and, without limiting the generality of the foregoing, all the Work shall be provided by Representatives of the Contractor.

   c. Terminal Policies/Manuals. Subject to Laws, the Owner agrees that it will comply with, and the Contractor's performance hereunder is subject to, all Crystal River Units 4 & 5 Facility Terminal operating policies and procedures that are issued from time-to-time by the Contractor. Subject to Laws, the Contractor agrees that it will comply with, and the Owner's performance hereunder is subject to, all Plant operating policies and procedures that are issued from time-to-time by the Owner. Each Party will promptly provide the other Party with copies of such policies and procedures as issued from time-to-time. In the event of a conflict between the Parties' respective policies and procedures, the Parties agree to cooperate to resolve any such conflict.

   d. Regulatory Compliance. Governmental or Regulatory Authorities may cause the Owner to incur expenses to comply with Laws, including, without limitation, (i) making additions or modifications to facilities at the Crystal River Units 4 & 5 Facility Terminal, (ii) changing methods of operation to comply with Laws, (iii) implementing testing or verification programs, (iv) implementing the conditions of any Permit necessary to operate the Crystal River Units 4 & 5 Facility Terminal, or (v) preventing, reducing, controlling or monitoring any emission, exposure or discharge into the environment (expenses arising from such requirements are hereinafter referred to as "Compliance Costs"). Compliance Costs shall include the actual or pro-rata cost of additional expense, changes or additions (including engineering and overhead expense) and subsequent direct and indirect costs, as may be escalated, of operating and maintaining such changes or additions, including the cost of changes in staffing for operations at the Crystal River Units 4 & 5 Facility Terminal. In the event the Owner is required to expend Compliance Costs, the Owner may either (i) notify the Contractor that the Owner intends to incur the Compliance Costs, or (ii) terminate the affected Work or portions of the Crystal River Units 4 & 5 Facility Terminal before the date upon which the Owner must incur Compliance Costs by providing written notice thereof to the Contractor. The Owner must make its election by advising the Contractor of the Owner's decision in writing thirty (30) days prior to the date in which the Owner must incur Compliance Costs in order to meet the effective date for such compliance, or such shorter time as may be necessary considering the effective date for such compliance. If the Owner does not timely notify the Contractor, the Contractor shall have the right to terminate this Attachment upon notice to the Owner.

2. TITLE & CUSTODY OF PRODUCT

a. Risk of Loss. The Owner shall have the risk of Loss for the Product at all times, unless the Loss is the result of the Contractor's negligence and then only to the extent of such negligence. In no event shall the Contractor be responsible for any Loss of any kind to the Product that results from any negligence of the Owner, contamination of the Product other than as a result of the Contractor's negligence, events or circumstances resulting in a Force Majeure, or resulting from natural occurrences or in connection with Product handling (assuming Good Industry Practice).

3. PRODUCT MEASUREMENT

a. Product Received. Product received into the Terminal will be determined by the Contractor pursuant to original bill of lading for truck and rail cars.

b. Inventory Amounts. Absent fraud or manifest error, the quantities of Product in the Tanks at any time will be determined from the Terminal inventory records maintained by the Contractor. Quantity determinations will be based on a short ton basis.

c. Meters and Scales. Terminal meters and truck scales (as applicable) will be calibrated annually and upon each completion of repair or replacement of a meter, in each instance at the Owner's expense. Calibration shall be performed in accordance with the most recent applicable standards. If a meter or truck scale is determined to be defective or inoperative, such Party shall immediately notify the other Party, and the Owner shall promptly make the necessary repair, replacement, or calibration. The Parties shall work in good faith to mutually agree on the discrepancy that results from a defective or inoperative meter or truck scale for a period of thirty (30) days. If the Parties cannot reach agreement, an independent inspector shall be engaged that is mutually acceptable to the Parties and his determination shall be final and binding, except for fraud of manifest error. The Parties shall split the costs of any independent inspector.

d. Inventory Reports. The Contractor shall transmit to the Owner a statement of receipts, deliveries, and ending inventory and, if applicable, copies of individual meter gauging documents. The Contractor shall provide monthly reporting of daily inventory data to the Owner in a format and on a date as may be mutually agreeable from time-to-time, provided that the Owner shall be responsible for the cost of any equipment necessary for the Contractor to transmit the data by electronic means.

4. TERMINAL HOURS & INSPECTION

a. Hours. The Contractor shall provide the Work during Standard Hours, except to the extent the Owner has requested, and the Contractor has accepted, for the Work to be provided during Non-Standard Hours.

b. Inspection. The Owner shall have the right, upon reasonable notice to the Contractor so as not to disrupt the Contractor's provision of the Work, to make periodic operational inspections of the Terminal, to conduct audits of any pertinent records on-site, conduct physical verifications of the amount of the Owner's Product in the Tanks. The Owner's rights under this subsection shall be exercised by the Owner and its Representatives in a way that will not interfere with or diminish the Contractor's provision of the Work.

5. SUSPENSION OF WORK.

a. Emergency Terminal Shutdown. The Contractor shall have the authority to shutdown the Terminal in the event of an emergency. The Contractor shall immediately provide notice to the Owner in the event of any shutdown of the Terminal by the Contractor in the event of an emergency.

b. Owner Suspension. Except in cases of emergency requiring immediate suspension or shutdowns, the Owner shall provide the Contractor with at least forty-eight (48) hours written notice prior to any planned suspension of the Plant, which notice shall include the estimated period of the suspension ("Owner Suspension Period"). To the extent possible under then-prevailing circumstances, the Owner shall provide the Contractor with at least forty-eight (48) hours written notice prior to any termination of the Owner Suspension Period.

EXHIBIT A

DETAILED DESCRIPTION OF THE WORK AND ADDITIONAL DEFINED TERMS FOR THIS AMENDMENT

1. TERMINAL OPERATIONS. The Work shall be limited to the provision of the following Work to the Crystal River Units 4 & 5 Facility Terminal, and all Work shall be performed by Contractor in accordance with Good Industry Practice:

   a. *Personnel.* The Contractor shall have sole discretion to determine the number of personnel necessary to provide, or cause to be provided, the Work.

   b. Terminal Operation. The Contractor shall provide for the operation of the Terminal during Standard hours (and Non Standard hours, on an as needed basis) as required for contractor to monitor and operate the Terminal. The Contractor shall be the manager of the Work provided to the Terminal. As such, the Contractor shall have the flexibility to schedule the provision of the Work in a manner that allows the Contractor to be absent from the Terminal during Standard Hours during any work week, provided that such absences from the Terminal does not result in a breach of the Contractor's obligations to provide the Work and/or create a lack of urea laden liquor and/or transfer of urea laden liquor sufficient for the Owner's operations. An absence from the Terminal that complies with the foregoing shall not be a breach of the Amendment.

      The Work includes observations and unloading of urea from railcars and highway tank trucks and inventory management of the urea in the terminal storage tank. This shall include but is not limited to monitoring storage tank levels, ordering urea product, arranging for rail or truck transportation to the site, operating the railcar mover to position loaded railcars for unloading and positioning empty railcars for pickup by the railroad, contacting the railroad to deliver loaded railcars and pickup empty railcars, schedule periodic maintenance and fueling of railcar mover, and unloading the product into the storage tank. The Owner retains the right to manage the Terminal, if required. The "Terminal" is defined as below by way of WAHLCO and EPCR Drawings to Description and further clarified by markings made on a set of these drawings which will be provided to both parties under separate cover:

DRAWING NUMBER	DRAWING DESCRIPTION
2206-3510-317-003 (Rev. 3)	Urea Unloading Pump Skid
2206-3510-317-004 (Rev. 3)	Urea Dilution Pump Skid (Demin Water)
2206-3510-317-005 (Rev. 3)	Urea Transfer Pump Skid

ANCILLARY TANKS	DESCRIPTION
Urea Demin Water Tank	
Urea Solution Storage Tank	
2206-3510-317-006 (Rev. 3)	SCR Urea Solution Day Tank
2206-3510-317-008 (Rev. 3)	AMM Urea Solution Day Tank
2206-3510-317-014 (Rev. 3)	SCR Hydrolyzer Blowdown Tank
2206-3510-317-015 (Rev. 3)	AMM Hydrolyzer Blowdown Tank

c. [redacted]

d. *Information Services*. The Contractor will provide Product shipment data entry and inventory accounting services for the receipt and offloading of rail cars and releasing empty railcars to the rail carrier, if required. The Contractor will provide the Owner with Monthly activities reports summarizing receipts, shipments, beginning and ending inventory, Product consumption, environmental, health and safety spending, and operating supplies spending, and any other necessary information reasonably requested by the Owner.

e. *Technician Compliance and Response Services*. The Contractor's technicians will: (i) revalidate and update (if required) the Terminal's operating procedures annually, (ii) timely report to the Owner environmental, health and safety information regarding the Terminal in connection with the provision of the Work, (iii) participate in the Owner's management of change process and perform tasks assigned by the Owner in connection therewith such as responsibility for updating standard operating procedures, training, awareness programs, and pre-start up safety reviews, each as related to the Terminal, (iv) provide Product awareness training at the Terminal and (v) hose testing and inspection at the Terminal.

f. *Inventory Management Services*. The Contractor shall be responsible for ensuring adequate inventory to conform to the operation rates of the Plant as stated to the Contractor in writing. The Contractor warrants to the Owner that all Product delivered by the Contractor to the Terminal will be conforming Product and otherwise in compliance with Laws. The Contractor shall be responsible for notifying the Owner of any non-conforming Product. The Contractor, as supplier of the Product, is responsible for providing a Certificate of Analysis for every Product delivery. If Product quality, as indicated on the Certificate of Analysis, is in non-conformance, the Contractor shall either reject the Product or acquire the agreement of the Owner to unload and receive the Product. In the alternative, the Owner reserves the right to inspect all shipments of Product upon arrival and to either reject those containing Product that do not meet the specifications, provided that the Owner shall be responsible for any errors or omissions with respect to such testing and the Contractor shall have no responsibility for any non-conforming Product that the Owner permits to enter the Tanks, the effect on the Tanks or other equipment as a result thereof, or the effect on the Owner's Plant as a result of such failed inspection. The cost of replacing non-conforming Product shall be for the Contractor's account, unless such Product is permitted to enter the Tanks as a result of a failed inspection by the Owner. In no event will the Contractor be obligated to pay costs related to Supplier rail car detention charges or Rail Road storage or demurrage charges unless such charges result from Contractor negligence.

2. FEES.

a) [redacted]

[redacted]

[redacted]

1. DEFINITIONS

"Addendum" means any Addendum entered into between the Parties to this Agreement from time-to-time that supplements or amends this Agreement.

"Affiliate" means any Person that controls, is controlled by, or is under common control with a specified Person. For purposes of this definition, "control" shall mean the power, whether direct or indirect, and whether by exercise of voting power or contract or otherwise, to direct the management policies and decisions of another Person.

"Agreement" has the meaning give to it in the Recitals.

"Claim" means any action, suit, proceeding, hearing, investigation, audit, litigation, charge, complaint, claim, or demand by any Person.

"Compliance Costs" has the meaning given to it in Attachment A, Section 1(d).

"Contact Person" means the Person designated by each Party in writing from time-to-time as being authorized to make operating decisions on behalf of such Party in connection with this Agreement.

"Customer" means all customers of the Operator, including the Owner and its Affiliates.

"Effective Date" has the meaning given to it in the Recitals.

"Environmental Laws" means all applicable laws, statutes, rules, regulations, ordinances or interpretations having the effect of law of any Governmental or Regulatory Authority relating to the environment, human health or safety, pollution or other environmental degradation or Hazardous Materials.

"Fees" has the meaning given to it in Attachment A

"Good Industry Practice" means the Operator shall perform, and shall require its Representatives to perform, the Services in accordance with the Operator's, and to the extent applicable the Owner's, documented operating procedures and in accordance with recognized industry standards and practices, which shall include, without limitation, the provision of the Services in good faith and the performance of its duties in a lawful, safe, cost-effective and otherwise commercially reasonable manner, subject to the Exhibits.

"Governmental or Regulatory Authority" means any congressional body, court, tribunal, arbitrator, authority, agency, commission, official or other instrumentality of the United States or any of its states or territories, or any of their respective counties, cities, or other political subdivisions.

"Hazardous Materials" means (a) petroleum or petroleum products, fractions, derivatives or additives, natural or synthetic gas, asbestos, urea formaldehyde foam insulation, polychlorinated biphenyls and radon gas, (b) any substances defined as or included in the definition of "hazardous wastes," "hazardous materials," "hazardous substances," "extremely hazardous substances," "restricted hazardous wastes," "special wastes," "toxic substances," "toxic chemicals" or "toxic pollutants," "contaminants" or "pollutants" or words of similar import under any Environmental Law, (c) radioactive materials, substances and waste, and radiation, and (d) any other substance the exposure to which is regulated under any Environmental Law.

"Laws" means all applicable laws, statutes, rules, regulations, ordinances, decisions, orders, or interpretations having the effect of law of any Governmental or Regulatory Authority, and "Laws" includes, without limitation, all Environmental Laws.

"Liability" or "Liabilities" means all Claims and Losses, regardless of whether any such Claims or Losses would be required to be disclosed on a balance sheet prepared in accordance with generally accepted accounting principles consistently applied or is known as of the Effective Date.

"Loss" or "Losses" means any loss, damage, injury, breach of duty or warranty, diminution in value, exposure, settlement, judgment, award, punitive damage award, fine, penalty, fee, charge, demurrage, cost or expense (including, without limitation, reasonable costs of attempting to avoid or in opposing the imposition thereof, interest, penalties, costs of preparation and investigation, and the reasonable fees, disbursements and expenses of attorneys, accountants and other professional advisors), as well as with, respect to compliance with the requirements of Environmental Laws, expenses of remediation and any other remedial, removal, response, abatement, cleanup, investigative, monitoring, or record keeping costs and expenses.

"Month" means a calendar month.

"Non-Standard Hours" means any time period that is not Standard Hours, including Owner's holidays.

"Operator" has the meaning given to it in the Recitals.

"Owner" has the meaning given to it in the Recitals and any permitted successor or assignee of Owner to this Agreement.

"Party" means the Owner or the Operator and the case may be or the context requires.

"Permits" means any permit, license, exemption, action, certificate of authority, authorization, approval, or registration issued by, or required to be issued by, a Governmental or Regulatory Authority in connection with the Owner's use or operation of the Plant or the Operator's provision of the Services.

"Person" means any natural person, corporation, limited liability company, general partnership, limited partnership, proprietorship, other business organization, trust, or Governmental or Regulatory Authority.

"Product" means commercial grade urea liquor.

"Plant" means owner Crystal River Energy Complex in Citrus County, Florida.

"Release" means the presence, release, disposal, discharge, dispersal, leaching or migration into the indoor or outdoor environment or into or out of any property, including the movement of Hazardous Materials through the air, soil, surface water, ground water or property other than as specifically authorized by (and then only to the extent in compliance with) all Environmental Laws and Permits.

"Representative" means any Person that is an agent, contractor, servant, employee or licensee of another Person.

"Routine PM" has the meaning given to it in Attachment A.

"Sales Agreement" means that certain Urea Purchase Confirmation Agreement, dated December 11, 2007 between Terra Industries Inc. and the Owner, as may be amended from time-to-time.

"Standard Hours" means eight (8) hours per day (7:00 a.m. to 3:30 p.m.), Monday through Friday, excluding Owner's holidays.

"Tanks" means the storage vessels and associated equipment, controls, and instrumentation located at the Terminal that supply Product to the Owner's selective catalytic reduction system to reduce NOx emissions in flue gas emitted from the Plant.

"Temporary Service Suspension" has the meaning given to it in Section 5(a) of Attachment A.

"Terminal" has the meaning given to it in Exhibit A
"Work" has the meaning given to it in Section 1(a) of Attachment A.

Contract Employee
Code of Ethics Acknowledgment Form

Please go to the following website to review the Progress Energy Code of Ethics prior to signing this Acknowledgment Form. Hard copies are available upon request.

http://www.progress-energy.com/investors/corpgov/codeofethics.asp

I have read the Progress Energy Code of Ethics. I understand that the principles stated in the Code of Ethics represent those of Progress Energy as they relate to the work I perform as an independent contractor (or as an employee of an independent contractor of Progress Energy), and that violating those principles, or the legal and regulatory requirements applicable to my work may result in disciplinary action by my employer. I agree to abide by and support the legal and regulatory requirements applicable to my work. I understand that if I have questions concerning appropriate ethics or relevant legal and regulatory requirements, I should consult with my supervisor.

____
Signature of Contract Employee

____
Name of Contract Employee

____
Date

____
Contractor Organization

Contractor shall maintain completed forms. Do not return completed forms unless they are specifically requested by Owner.

One-Time Non-Nuclear
Revision 09/09/2008
#5391

CODE OF ETHICS COMPLIANCE PLAN

CONTRACT # _____406464_____

Company Name: _____Terra Industries Inc.______________________________________

Person providing this information: __Beth Niehus______________________________________

Title: __Director, Human Resources______________________________________

Phone number: _712-277-7231______ Email: __bniehus@terraindustries.com______________

1. Owner requires Contractor adherence to conduct/ethics compliance standards for its workers. Owner offers its own Code of Ethics standards for any company desiring to use them; however, if exception is taken, Contractor is required to demonstrate that their workers are covered by Contractor's equivalent program. Please indicate the program which applies to this Contract?

   ___ Owner's Code of Ethics

   _X_ Contractor's internal program standards (Owner review and approval required. Please attach information about your Code of Conduct/Ethics, acknowledgment and documentation procedures.)

2. Who within your company has overall responsibility for worker acknowledgement forms related to the Code of Conduct/Ethics?

   Name: Human Resources Department – Theresa Tucker_______________

   Title: __Benefits Administrator______________________________________

   Phone Number: _712-279-8747__________ Email: _ttucker@terraindustries.com_

3. What is your process for ensuring each of your employees provides written acknowledgment of his/her awareness of code of Conduct/Ethics standards and expectations prior to performing work for Owner?

   This acknowledgment is part of the new hire process and is reviewed when employees are hired.

   Additionally, on an annual basis all employees are required to review and sign the Code of Ethics and Standards of Business Conduct and the Conflict of Interest Policy.____________

4. Describe the retention plan for the Code of Conduct/Ethics acknowledgement forms once signed by your employees.

   Format Stored: ___ Hard Copy ___ Scanned PDF _X Other (explain) _Electronic__________

   Location Stored: ______Network drive.______________________________________

5. Describe the review/audit process for the signed acknowledgement forms when Owner requests to review.

   Point of contact: Brenda Godfredson___ Phone Number: __712-277-7343_____

   Email: bgodfredson@terraindustries.com_

   Location where forms can be reviewed: Sioux City, Iowa__

   Notification interval required for review (how many hours/days): _2 business days_____

Procedure for getting access: ___Contact Human Resource Department at Terra.______

BACKGROUND INVESTIGATION/DRUG SCREEN COMPLIANCE PLAN

CONTRACT # __406464____________

Company Name: Terra Industries Inc.____________________

Person providing this information: ___Beth Niehus_______________

Title: Director, Human Resources______________

Phone number: __712-277-7231 Email: ___bniehus@terraindustries.com___

1. Which of the two preferred vendors will you use to perform your background investigations?

   _X__ Sterling (Preferred Vendor)

   ___ A Check America Inc. (Preferred Vendor)

   If leveraging another company, you will be required to submit your program to Owner for approval.

   ___ Other: ___________________________________ (Owner approval required)

2. Who has overall responsibility for ensuring the completion of the background investigations and drug screens within your company?

   Name: ___Brenda Godfredson______________________

   Title: ___Human Resources Supervisor____________

   Phone Number: ___712-277-7343__ Email: __bgodfredson@terraindustries.com______

1. Who within your company reviews findings of background investigation and drug screen results to confirm that a worker satisfies Owner's criteria, as defined in the Contract?

   Name: _Brenda Godfredson____

   Title: _Benefits Supervisor____

   Phone Number: _712-277-7343____ Email: __bgodfredson@terraindustries.com___________

2. Describe the retention plan for the background investigation/analysis data and drug screen results.

   Format Stored: ___ Hard Copy ___ Scanned PDF _X__ Other (explain) _online document

   Location Stored: ___Network Drive___________________________________

3. Describe the review/audit process for this data when Owner requests to review.

   Point of contact Beth Niehus______ Phone Number: _712-277-7231__________

   Email: ___bniehus@terraindustries.com_____________________________

   If using Sterling and/or A Check America, Inc. . . . Will you provide electronic access to Owner to through Sterling and/or A Check America, Inc.'s website when background/drug screen data is needed as defined in the Contract?

   ___ Yes _X__No If no, or not using an Owner recommended vendor, will records be provided by:

_X__ Fax ___ Hardcopy via mail _X__ Other (explain) _E-mail_______________

SUPPLIER DIVERSITY & BUSINESS DEVELOPMENT
SUBCONTRACTING REPORT

REPORTING METHOD AND DEFINITIONS

REPORTING METHOD

Please complete the attached form, Supplier Diversity & Business Development Subcontracting Report, to record your awards with small business concerns that are directly related to fulfilling a specific Progress Energy contract. Provide contract number, dollar amount and the per cent of award to small business concerns. Quarterly and cumulative annual period reporting is required.

REPORTING TIME SCHEDULE

Please provide the information requested for subcontracting quarterly report by the 15th of the month following the end of the quarter that you are reporting. The completed form may be faxed to Progress Energy Service Co., LLC, Manager-Supplier Diversity & Business Development, (919) 546-6750 or mailed to Progress Energy Service Co., LLC, Manager-Supplier Diversity & Business Development, P.O. Box 1551 (PEB-2), Raleigh, NC 27602.

SMALL BUSINESS CONCERNS (SBC) DEFINITIONS*

- **Small Disadvantaged Business Concern** (SDB) - A business at least 51 percent of which is owned (or, in the case of publicly owned businesses, at least 51 percent of the stock of which is owned) by one or more minority individuals or other individuals found to be disadvantaged as established by the Small Business Administration and whose management and daily operations are controlled by individuals including the following minority classes (for clarification, refer to FAR 52.219-8).

Minority Type:

- African American Male	- Hispanic American Male	- Asian-Pacific American Male
- African American Female	- Hispanic American Female	- Asian –Pacific American Female
- Native American Male	- Asian-Indian American Male	
- Native American Female	- Asian-Indian American Female	

Native American	Includes American Indians, Eskimos, Aleuts and Native Hawaiians
Asian Pacific	Includes U.S. citizens where origins are from Japan, China, Philippines, Vietnam, Korea, Samoa, Guam, U.S. Territories of Pacific, Laos, Cambodia and Taiwan
Asian Indian	Includes U.S. citizens where origins are from India, Pakistan and Bangladesh

- **Women-Owned Business Concern** (WOSB) – A business that is at least 51 percent owned by a non-minority woman and who controls the daily management (for clarification, refer to FAR 52.219-8).

- **Hubzone Small Business Concern** (HBZ) – A business that appears on the list of qualified hubzone small business concerns maintained by the Small Business Administration.

- **Veteran-owned Small Business Concern** (VOSB)- A business at least 51 percent of which is owned (or, in the case of publicly owned businesses, at least 51 percent of the stock of which is owned) by one or more veterans and whose management and daily operations are controlled by one or more veterans.

- **Small Business Concern** (SB)- A business independently owned and operated that is not dominant in its field and that meets Small Business Administration standards as to the number of employees, generally under 500, and/or dollar volume of its business (for clarification, refer to 13 CFR Part 121 and FAR 19.102).

- **Handicapped/Sheltered Workshop** - this must be a charity organization or institution conducted not for profit, but for the purpose of carrying out a recognized rehabilitation program for handicapped workers and/or providing individuals with paid employment.

SUPPLIER DIVERSITY & BUSINESS DEVELOPMENT SUBCONTRACTING REPORT

Date ______________________________
Contractor Name ______________________________
Qtr. ______________________________
Type of Business ______________________________
Contract Number ______________________________
Dollar Amount of Contract ______________________________

CERTIFIED SMALL BUSINESS CONCERNS INFORMATION

List all small business concerns subcontractor(s) used on the project and subcontracted percent and amount

NAME	PRODUCTS/SERVICES TO BE PROVIDED	$ AMOUNT	YTD $ Amount	%	*SBC code

SOURCING EFFORT FOR CERTIFIED SMALL BUSINESS CONCERNS

List all small business concerns subcontractor(s) contacted on the project that will not be used

NAME	ADDRESS	PHONE NUMBER	CONTACT	*SBC code

LIST ANY ORGANIZATIONS, AGENCIES, OR GROUPS THAT YOU CONTACTED TO SOURCE CERTIFIED SMALL BUSINESS CONCERNS

NAME	ADDRESS	PHONE NUMBER	CONTACT

Attach sheet if additional space is needed.

Suggested Organizations:

Carolinas Minority Supplier Development Council 704-536-2884
South Carolina's Governor's Office of Small & Minority Business Assistance 803-734-0657
State of North Carolina Historically Underutilized Business Program 919-733-8965
Raleigh/Durham Minority Business Development Center 919-833-6122
The North Carolina Institute of Minority Economic Development 919-831-2467
National Association of Women Business Owners 703-506-3268

One-Time Non-Nuclear
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PEF-POD4-00131

PEF'S RESPONSE TO STAFF'S FOURTH REQUEST FOR PRODUCTION OF DOCUMENTS NO.14

Docket No. 090007-EI
POD 14.1 - Cap Expenditure Breakout
Witness: Patricia Q. West

POD 2010 Cashflow 36% Nuclear Filing; 64% ECRC	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Total Labor with Burdens	54,050	56,005	70,725	56,120	56,848	65,550	69,000	98,900	111,550	112,125	119,025	78,890	948,788
Total Materials with Burdens	1,907,361	2,108,937	471,148	58,650	74,750	863,690	1,911,300	58,650	4,785,035	1,612,070	32,200	29,900	13,913,691
Total Contract Services with Burdens	687,526	1,631,036	2,091,032	3,166,555	3,641,404	3,641,904	5,036,385	4,721,401	3,367,614	3,367,114	2,274,393	2,274,393	35,900,757
Total Other Costs with Burdens (Estimated with $3M indirect)	270,095	269,750	277,678	270,288	270,819	273,445	277,100	284,110	288,845	289,038	293,348	277,911	3,342,425
[redacted]													

ECRC Portion 64%

[redacted]

New direct view POD cashflow was revised August 2009 for 2010 Budget
Has not been entered in budgeting system and Burdens and Indirects were estimated

Project	Chargeby	Task	Resource	Description	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	New Estimate Total
20069134	60LT9D	E0301	EBC	Company Labor Engineering	16,000	16,000	16,000	16,000	16,000	16,000	25,000	25,000	25,000	25,000	25,000	25,000	246,000
20069134	60LT9D	L0301	EBC	Company Labor Safety	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	24,000
20069135	60LT9D	S0201	EBC	Company Labor Business Services	0	0	5,000	0	0	5,000	0	0	5,000	0	0	5,000	20,000
20069134	60LT9D	L0401	EBC	Company Labor Regulatory	0	0	5,000	0	433	5,000	0	0	0	0	0	0	10,433
20069135	60LT9D	L0411	EBC	Company Labor Environmental	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	8,000	96,000
20069135	60MBMD	S0501	EBC	Company Labor Facilities	3,519	4,177	4,877	7,057	4,993	4,663	4,581	4,875	4,937	7,475	4,994	4,159	61,606
20069134	60LM7D	L0411	EBC	Company Labor Environmental	2,116	2,987	2,987	4,329	3,052	2,896	2,806	2,995	2,982	4,572	2,038	2,347	37,364
20069134	60LU7D	PRMGT	EBC	Company Labor Prj Mgmt	6,041	8,142	8,342	11,758	8,318	7,784	7,648	8,127	8,073	12,477	8,386	6,941	101,837
20069136	60LT9D	S0301	EBC	Company Labor Doc Control	1,000	2,000	3,000	1,000	2,000	3,000	4,000	5,000	6,000	7,000	8,000	9,000	51,000
20069134	60LT9D	E0501	EBC	Company Labor Engineering	2,000	2,000	2,000	2,000			5,000			2,000			15,000
20069134	60LT9D	S0201	EBC	Company Labor Business Services													0
20069134	60LT9D	T0301	EBC	Company Labor Attend Training		200		200		2,000			3,000				5,400
20069134	60LT9D	W0101	EBC	Company Labor Planning													0
20069140	60LT9D	M0301	EBC	Company Labor Contract Analyst	2,000	2,500	4,500	3,600					2,000	2,500	4,600	3,600	25,200
20069140	60LT9D	M0301	EBC	Company Labor Contract Analyst Construction Contract					5,000								5,000
20069140	60LT9D	W0601	EBC	Company Labor Administration													0
20069134	60LT9D	W0601	EUR	POD Transmission Work to Move 13KV Line								30,000	30,000	35,000	40,000		135,000
				Company Labor Direct View Charges	42,876	48,706	61,906	65,994	49,786	68,303	69,038	85,897	96,672	106,080	103,888	66,348	833,240
				Estimated Burdens (includes Labor Burdens)	11,174	7,898	8,219	126	7,082	9,247	6,985	12,903	18,876	8,695	15,138	12,944	113,944
				Total Financial View Labor Estimate	54,050	56,604	70,125	66,120	[illegible]	77,550	76,023	[illegible]	115,548	114,775	119,026	79,292	[illegible]
20069134	60LT9D	L0411	LOS	Golder	5,000		5,000		5,000								15,000
20069134	60LT9D	W0601	LOS	Permit Fee FDEP/COE Permit			7,600			7,600			7,600				22,800
20069139	60LT9D	E0301	LOS	POD - GeoView Geophysical Survey					0								0
20069140	60LT9D	E0301	LOS	POD - Survey Support	11,000	11,000	11,000	7,000	7,000	7,000	4,000	4,000	4,000	7,000	4,000	4,000	81,000
20069130	60LT9D	W0601	LOS	POD Facilities needed for Construction	8,000	8,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	136,000
20069140	60LT9D	E0301	LOS	POD Inspecting Construction Labor	15,000	15,000	16,000	16,000			4,000			4,000			69,000
20069140	60LT9D	W0601	LOS	Construction Site Prep - Mass Est. - 2,207,489	110,374	220,749	662,245	1,214,119									2,207,489
20069140	60LT9D	W0601	LOS	Construction Cooling Tower Basin - Mass Est. - 8,361,353		836,135	836,135	836,135	1,672,271	1,672,271	1,672,271	836,135					8,361,353
20069140	60LT9D	W0601	LOS	Construction Cooling Tower Intake Structure - Mass Est. - 27,719,621					1,385,981	1,385,981	2,771,962	2,771,962	2,771,962	2,771,962	1,385,981	1,385,981	16,631,773
20069140	60LT9D	W0601	LOS	Construction Cooling Tower Discharge Structure - Mass Est. - 1,501,302											300,260	300,260	600,521
20069140	60LT9D	W0601	LOS	Indirect Costs - Mass Estimate - 10,503,029	525,152	525,152	525,152	1,050,304	525,152	525,152	525,152	1,050,304	525,152	525,152	525,152	525,152	7,352,127
20069140	60LT9D	W0601	LOS	Specialty Vendor Support		2,000	2,000	10,000	16,000	10,000	25,000	25,000	25,000	25,000	25,000	25,000	189,000
20069140	60LT9D	W0601	LOS	Misc. contracts	15,000	15,000	15,000	22,000	19,000	22,000	22,000	22,000	22,000	22,000	22,000	22,000	240,000
				Contract Labor Direct View Charges	667,526	1,631,036	2,081,052	3,164,545	3,661,404	3,641,804	5,036,365	4,721,481	3,367,614	3,387,114	2,276,533	2,274,339	35,909,757
				Estimated Burdens (No Burdens)	0	0	0	0	0	0	0	0	0	0	0	0	0
				Total Financial View Contract Labor Estimate	667,526	1,631,036	2,081,052	3,164,545	3,661,404	3,641,804	5,036,365	4,721,481	3,367,614	3,387,114	2,276,533	2,274,339	35,909,757
20069135	60LT9D	W0601	MML	ACCH EvapTech Retainage C-43309 Inv 200						69,160							69,160
20069135	60LT9D	W0601	MML	EvapTech Change Add electrical power receptacles			28,460										28,460
20069135	60LT9D	W0601	MML	EvapTech Change Add electrical power to Davit			23,880										23,880
20069137	60LT9D	W0601	MML	EvapTech Change Add Limitorque River Valve operators & upgrade valves	200,000												200,000
20069135	60LT9D	W0601	MML	EvapTech Change Add Platforms at [illegible] & riser valves		18,850											18,850
20069135	60LT9D	W0601	MML	EvapTech FD CT Procure & Construct - Construction & Testing									4,127,400	1,375,800			5,503,200
20069135	60LT9D	W0601	MML	GE - Added 4160V Switchgear	286,912	95,637											382,549
20069135	60LT9D	W0601	MML	GE - Added 480V MCC	118,790	93,736											212,527
20069135	60LT9D	W0601	MML	POD Equip - Add - Vacuum Priming System - Lynn Engineering	64,660												64,640
20069135	60LT9D	W0601	MML	POD Equip - Add [illegible] Wash Pumps - Flowserve		292,182											292,182
20069135	60LT9D	W0601	MML	POD Equip - Added Transformers - GE 480V Transformer		62,235											62,235
20069135	60LT9D	W0601	MML	POD Equip - Added Transformers - Virginia 4160V Transformer		347,445											347,449
20069135	60LT9D	W0601	MML	POD Equip - Large Butterfly Valves - Control Equipment Company			295,344										295,344
20069135	60LT9D	W0601	MML	POD Equip - Large Fiberglass Piping - [illegible]		909,250											909,250
20069135	60LT9D	W0601	MML	POD Equip - Lift Pumps - [illegible]						903,875	1,309,000						2,212,875
20069135	60LT9D	W0601	MML	POD Equip - Main Switch Gear - ABB	281,144	93,728											374,872
20069135	60LT9D	W0601	MML	POD Equip - Traveling Screens - Siemens	678,000												678,000
20069135	60LT9D	W0601	MPM	Misc. Material & Consumables	33,500	30,000	50,000	50,000	70,000	70,000	50,000	50,000	25,000	25,000	25,000	25,000	500,000
				Material Direct View Charges	1,667,576	1,932,854	399,184	50,000	70,000	782,035	1,359,000	50,000	4,152,400	1,400,800	25,000	25,000	12,064,382
				Estimated Burdens (Includes Taxes & Warehouse Burden)	219,765	278,079	71,684	3,850	4,750	121,165	262,300	8,680	633,635	211,270	7,300	4,300	1,836,378
				Total Financial View Material Estimate	1,887,341	2,210,937	471,318	53,850	74,750	903,050	1,621,300	58,680	4,786,035	1,612,070	32,300	29,300	[illegible]
20069135	60LT9D	L0411	OMC	Amer Aerial Photos	500		500		500		500		500		500		3,000
20069135	60LT9D	L0411	OML	Meals, Travel, Lodging			800		167	800							2,157
20069134	60LT9D	PRMGT	OML	Meals, Travel, Lodging	500			500			500			500		500	2,500
20069134	60LT9D	E0301	OML	Meals, Travel, Lodging													0
20069134	60LT9D	S0201	OML	Meals, Travel, Lodging			2,000				2,000				2,000		6,000
20069140	60LT9D	W0601	OML	Meals, Travel, Lodging					130								130
20069128	60LT9D	W0501	OVE	Vehicle Mileage Distribution	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	12,000
				Other Costs Direct View Charges	2,000	1,000	4,000	1,500	1,797	1,500	4,000	1,000	1,500	1,500	3,500	1,500	24,797
				Estimated Burdens (Includes Indirect Support)	269,065	269,750	273,678	268,785	268,092	271,945	273,106	283,110	297,345	287,538	286,848	276,411	3,317,636
				Total Financial View Other Costs Estimate	271,065	269,750	277,678	270,285	270,889	273,445	277,106	284,110	298,845	289,038	290,348	277,911	[illegible]

Total [illegible]

PEF'S RESPONSE TO STAFF'S FOURTH REQUEST FOR PRODUCTION OF DOCUMENTS NO.15

CR No. 865392

Progress Energy

Mesa Associates, Inc.
10604 Murdock Drive
Knoxville, TN 37932

Attention: Tim Cutshaw

CONTRACT NO. 221186
WORK AUTHORIZATION NO. 24
EFFECTIVE February 1, 2009

Under the terms of the above-referenced Contract, Progress Energy Service Company, LLC, not in its individual capacity, but solely as agent for Progress Energy Florida, Inc. (hereinafter "Owner") offers the following work to your company:

Scope of Work

Contractor shall furnish all labor, tools, materials, equipment, transportation, and supervision necessary engineering and design services to support the construction of New EPU Cooling Tower Project, hereinafter known as the "Work." A general description of the Work is provided below, and a complete description is contained in Exhibit 1 – "Point of Discharge Statement of Work".

- **EPU Cooling Tower Basin & Foundations** – The scope of this Work is to engineer & design the new EPU cooling tower cold water basin and foundations as defined below. Construction will be completed under a separate contract. The detailed requirements for this work are stated in Section 3 of this document and the DCM. The basin and foundations are defined as all concrete components and structures necessary to support the installed cooling tower and to facilitate proper hydraulic operation of the cooling tower system. The technical requirements for this work include:
  - Design of the basin and foundations subject to the following boundary conditions:
    - Contractor will base their design on the cooling tower Contractor's loading diagram and mounting & support requirements. The design and engineering details of all interfaces between the cold water basin and the cooling tower structure will be developed by the cooling tower contractor
    - one physical boundary of this scope is up to and including the first flanged connection (with isolation valve & controls)
    - a second physical boundary of this scope is up to & including the first electrical box off the cooling tower maintenance area
    - this scope includes the 40' maintenance area around the circumference of the cooling tower basin
    - the cooling tower basin height will be adequate to allow gravity drain back to the Discharge Canal
  - the cooling tower and basin design will allow for easy access and cleaning of marine growth from the basin and cooling tower structural members
  - maintenance area (approximately 40' perimeter around the cooling tower basin)

CR No. 865392

Progress Energy

Mesa Associates, Inc.
10604 Murdock Drive
Knoxville, TN 37932

Attention: Tim Cutshaw

CONTRACT NO. 221186
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EFFECTIVE February 1, 2009

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        - one physical boundary of this scope is up to and including the first flanged connection (with isolation valve & controls)
        - a second physical boundary of this scope is up to & including the first electrical box off the cooling tower maintenance area
        - this scope includes the 40' maintenance area around the circumference of the cooling tower basin
        - the cooling tower basin height will be adequate to allow gravity drain back to the Discharge Canal
    - the cooling tower and basin design will allow for easy access and cleaning of marine growth from the basin and cooling tower structural members
    - maintenance area (approximately 40' perimeter around the cooling tower basin)

- electrical and instrumentation panels, conduits, cable trays, supports and restraints, for components mounted on the cooling tower basin or maintenance area
- the design will include appropriate maintenance handling equipment and systems,
- some geotechnical soil characterization has been done by Owner. Contractor is responsible for reviewing this information and finalizing the characterization as necessary to complete the cooling tower design.

- **Intake & Discharge Structures** – The scope of this Work is to engineer & design the intake and discharge structures. The scope of work for the intake and discharge structures are further detailed in Section 3 of this document, the DCM, and specifications for equipment within this scope of work (i.e., S-4 – Trash Racks & Traveling Screens, S-5 Concrete, S-6-1 Fiberglass Reinforced Piping, S-6-2 – HDEP Piping, and others). The boundary of this task is defined as follows:

  - Design requirements and drawings of termination detail for high voltage cables on the cooling tower equipment
  - Design requirements and drawings of termination detail for low voltage wiring at the first panel off the cooling tower
  - Design of cable and wire ways to the cooling tower basin and to the cooling tower
  - Design requirements and design for electrical power from the substation to the distribution center in the intake structure
  - Design requirements and design detail of instrumentation and controls to the Unit 1 / 2 control room DCS.
  - Piping to and from the cooling tower basin,
  - The scope of this work also includes all geotechnical sampling required to complete the final design of the intake and discharge structures.

- **Monitoring & Control Software & Hardware** – The scope of this Work is to design and develop the software and hardware for the equipment monitoring and control system for the new cooling tower equipment. The monitoring and control system must be compatible with the existing cooling tower Distributed Control System (DCS). The features of the monitoring and control system must be similar to the existing equipment. Contractor will work closely with Owner personnel in completing this work.
- Contractor will provide the technical and engineering expertise to design and develop the procurement specifications for the cooling equipment and systems identified above and further described in section 3 of this document and in the Design Criteria manual.
- Contractor will develop & implement the associated calibration and test procedures to demonstrate proper equipment capabilities during equipment and component startup.
- Contractor will supply all management, supervision, labor, equipment, materials, tools, consumable supplies, and each and every item necessary to perform the Work describe in this Work Authorization.
- Contractor will perform both on-site and off-site activities necessary to complete the stated design and develop procurement specifications.
- On site activities require preapproved access. Contractor will submit site access forms 48 hours before expected CREC access unless otherwise approved by the Designated Representative.

The result of this Work Authorization will be the final design for the construction and operation of Discharge Canal cooling equipment that provides a minimum of 2.33 B BTU/Hr of Discharge Canal heat removal.

Quality Assurance

The Work has been determined to be not Nuclear Safety Related.

The Contractor will not be required to perform work in radiation areas.

Contract Invoicing and Acceptance of Deliverables

[redacted]

[redacted]	
[redacted]	
[redacted]	
[redacted]	
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]

Contractor shall submit a monthly invoice for the actual hours worked that month. The invoice shall include a statement or be accompanied by time sheets showing each employee's name, classification, hours worked, applicable rate of compensation to Contractor. If any special equipment has been used, the invoice must also specify the equipment used, hours of usage, and rate of reimbursement for use.

Each monthly invoice will state the amount of fee included in that month's invoice, the percentage of fee charged that month, and the accumulated total amount of fee charged up to that point.

Invoices for Work performed under this Work Authorization should be sent to

Crystal River Nuclear Plant Unit 3
15760 West Powerline Street
Crystal River, FL 34428-6708
Attn: Accounting Representative (SA2I)

Schedule

[redacted]

Locations

The awarded Work shall be performed at Owner's Crystal River Energy Complex located near Crystal River, FL, and Contractor's offices located in Chattanooga, TN.

Designated Representative

Mark Hickman
mark.hickman@pgnmail.com
phone: 352-563-2943 ext 4233
Crystal River Unit 3 Nuclear Plant
15760 West Powerline Street (SA2C)
Crystal River, FL 34428-6708

is appointed as Owner's Designated Representative for the administration of this Work Authorization.

All Work shall be performed as directed by Owner's Designated Representative.

Target Price

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Taxes

Contractor assumes exclusive liability for all sales or use taxes applicable to any materials, supplies, equipment or tools purchased, rented, leased, used or otherwise consumed by Contractor in conjunction with the performance of the Work.

Retention

Owner will not withhold retention from Contractor's invoices (excluding any increases in fee earned as a result of early delivery of Project Milestones as detailed above, and the final invoice as detailed below) as long as the following conditions are met:

- Schedule: Contractor has met all schedule milestones such that major (30%, 70%, final) engineering packages are delivered on schedule
- Safety: Contractor has met the safety target of zero accidents.
- Cost: The current accumulated project cost at the time of any monthly invoice, is less than one hundred ten percent (110%) of the estimated accumulated project cost for that month.

If these conditions are not met, then a deduction of ten percent (10%) shall be retained from all amounts invoiced, except the invoice for retention and the invoice for final payment. Subject to the above conditions, payments will be made not later than thirty (30) days after receipt of Contractor's invoice.

Owner shall withhold a retention of five percent (5%) of the actual Work Authorization Price from Contractor's final payment in order to cover performance incentives related to the construction of the work designed by Contractor. This retention will be released to Contractor once project construction is substantially complete or within one year from acceptance, by Owner, of Contractor's CFC package.

Note 2: Schedule Incentives only apply to the fee charged on the month's invoice to which the relevant Project Milestones apply. In any month in which fee is either increased or decreased as a result of Schedule Incentives, that month's invoice shall clearly state the percentage of fee applicable to that month, the actual amount of fee included in the invoice, and the difference between the actual amount of fee included in the invoice and the amount fee would have been if Schedule Incentives had not been applied. Any additional fee earned as a result of early delivery of Project Milestones shall be retained by Owner and paid to Contractor as a portion of the final payment.

Note 3: Schedule Incentives shall only be applied if the actual, overall project schedule is affected by the Contractor's early or late delivery and acceptance of Project Milestones. I.E. if Contractor misses a Milestone and thereby reduces his invoice, Contractor can earn the amount of fee deducted from that invoice back if Contractor is able to recover the overall project schedule and meet final deadlines. By the same token, Owner will only pay Contractor any retained amounts earned as a result of increases in fee due to early delivery of Project Milestones if Contractor's early delivery betters the overall project schedule.

Note 4: The maximum decrease to revenue as a reslt of Schedule Incentivesshall not exceed the total fee of 8%.

Taxes

Contractor assumes exclusive liability for all sales or use taxes applicable to any materials, supplies, equipment or tools purchased, rented, leased, used or otherwise consumed by Contractor in conjunction with the performance of the Work.

Retention

Owner will not withhold retention from Contractor's invoices (excluding any increases in fee earned as a result of early delivery of Project Milestones as detailed above, and the final invoice as detailed below) as long as the following conditions are met:

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Owner shall withhold a retention of five percent (5%) of the actual Work Authorization Price from Contractor's final payment in order to cover performance incentives related to the construction of the work designed by Contractor. This retention will be released to Contractor once project construction is substantially complete or within one year from acceptance, by Owner, of Contractor's CFC package.

Retention (of final payment) shall be invoiced separately by the Contractor and payment shall be made not later than thirty (30) days after receipt of the invoice and all of the following have been completed:

(1) All design Work has been completed and accepted, , and receipt of all required documentation by Owner.

(2) A correct invoice covering the Work has been presented to Owner. This invoice will clearly state the following:

- Target Price and the amount of fee included in the Target Price
- Actual Project Cost and the amount of fee included in the Actual Project Cost
- Any amounts fee was increased or decreased as a result of Safety, Schedule, or Quality Incentives
- Any amounts the invoice is increased or decreased by as a result of Shared Savings or Shared Costs

Code of Ethics

Contractor, Contractor's employees, and employees of Contractor's subcontractor(s) performing Work under this Work Authorization shall comply with Owner's Code of Ethics. Owner will make the Code of Ethics available to Contractor in order for Contractor to provide a copy to any employee with (i) a presence for a single period of 15 calendar days or more upon property owned or leased by Owner (except right-of ways) or any of Owner's subsidiaries or affiliates and/or (ii) access to Owner's business critical infrastructure and/or (iii) security badge access to Owner facilities. Each such employee shall sign an Acknowledgment Form (Exhibit 4) in substantially the form set forth by Owner. Contractor shall retain the signed forms for Owner audit purposes for the term of the Contract plus one (1) year. The audit right provided herein shall not be restricted by any other audit provisions of the Contract. Contractor shall not be required to obtain signatures on Acknowledgement Forms for those employees assigned to Owner sites exclusively to provide storm support.

Contractor, Contractor's employees, and employees of Contractor's subcontractor(s) performing Work under this Work Authorization are obligated to comply with all applicable laws and regulations and with all applicable health, safety and security rules, programs and procedures. The Owner Code of Ethics identifies principles concerning lawful and ethical conduct that must be followed by Contractor's employees in the performance of Work. The Code of Ethics also provides for an AlertLine reporting mechanism that enables the reporting of suspected violations of law and of the Code of Ethics as a part of Owner's program to prevent and detect violations of law and criminal or unethical conduct.

Insurance

As required by the Insurance Section of the Contract, before any Work is performed and before any invoices are paid for Work performed under this Work Authorization, written proof of compliance with the insurance requirements of the above-referenced Contract must be on file with Owner on a certificate executed by an authorized representative of Contractor's insurer and identified by the Owner Contract number.

Order of Precedence

If any conflicts exist between the provisions of this Work Authorization and the provisions of the Contract under which this Authorization is let, or any Amendment to this Contract, the provisions of this Work Authorization shall govern the Work described above. All other items in the Contract or Contract Amendments remain unaffected by this Work Authorization.

This Work Authorization and the Contract, as amended, embody the entire agreement between Owner and Contractor for the Work described above. The parties shall not be bound by or liable for any statement, writing, representation, promise, inducement or understanding not set forth within this document, itself. No changes, modifications, or amendments of any terms and conditions of this Work Authorization are valid or binding unless agreed to by both parties in writing and signed by their authorized agents.

Electronic Submittals

Owner and Contractor acknowledge that documents requiring signatures may be transmitted electronically. Owner and Contractor stipulate that if this Work Authorization is transmitted electronically, the electronic transmittal of the original execution signatures shall be treated as original signatures and given the same legal effect as an original signature.

- next paragraph begins on the following page -

All other terms in the Contract or other Contract Amendments remain unchanged.

Please execute this Work Authorization, retain an original for your file, and return the other original within ten (10) calendar days to Sid Fowler, Progress Energy Service Company, LLC, P. O. Box 1551 (PEB-3C3), Raleigh, NC 27602, or via electronic transmittal to sidney.fowler@pgnmail.com.

Sincerely,

Tony Owen
Manager, NGG Major Projects
As Agent For
Progress Energy Florida, Inc.

Accepted:

MESA ASSOCIATES, LLC

By: ____________________

Name (printed): Timothy R. Catlow

Title: Vice President

Date: 3/10/09

Should the person's title who is executing this document not indicate that he/she is a corporate officer, an affidavit signed by a corporate officer shall be provided stating that the person whose name appears above is duly authorized to execute Contracts on behalf of the firm.

____
(Contractor to fill in name and title)

is appointed as the person to whom all official correspondence to Contractor concerning this Contract should be directed.

In accordance with the Federal Acquisition Regulation section 52.219, please check all that apply to your company. Please provide supporting documentation or certification to confirm the status for any categories checked under Small/Diverse Vendors.

[ ] Certified small business*
[ ] Veteran-owned business*
[ ] Service-disabled veteran-owned business*
[ ] Not a Small Business
[ ] HUBZone, 8(a) or disadvantaged business*
[√] Minority-owned business * *
[√] Women-owned small business * *

* As defined by the Small Business Administration (SBA): www.sba.gov
* * Certified by Progress Energy and as defined by SBA.

Register online at www.progress-energy.com/supplierdiversity

Work Authorization No. 221186-24

Exhibit 1

Statement of Work

Contractor's Scope of Work shall consist of the entirety Tasks 6a, 7a, 8a, and 10a, Tasks 1, 2, 3, and 4 as relative to the performance of Task 5a, and all planning and interfaces as necessary to fully perform the Work.

STATEMENT OF WORK

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STATEMENT OF WORK

INTRODUCTION / BACKGROUND

Owner's Crystal River Nuclear Unit 3 (CR3) is part of the larger Crystal River Energy Complex (CREC) located in Citrus County, Florida. The CREC is comprised of 4,738 acres and includes a single nuclear unit (CR3) and four coal-fired units, CR 1, 2, 4, and 5. CR3 and the four coal-fired units lie in the developed area of the site.

Cooling water for CR 1, 2, and 3 is withdrawn from an intake canal which connects to Crystal Bay and the Gulf of Mexico and returned to the Gulf via a common Discharge Canal. The Florida Department of Environmental Protection (FDEP) Issued a National Pollution Discharge Elimination System (NPDES) permit (FL0000159) with limits on the combined condenser flow from CR I, 2, and 3 to 1,898 million gallons per day (MGD) during the period of May 1 through October 31, and 1,613.2 MGD during the remainder of the year.

The 14-mile-long intake canal is dredged to a depth of approximately 20 feet (ft) to also accommodate coal barges which unload and dock on the south side of the Intake Canal, just west of the intakes for CR 1 and 2. The Intake Canal is bermed by northern and southern dikes. The northern dike continues along the channel for another 5.3 miles. There are openings in the dikes at irregular intervals to allow north-south boat traffic in the area of CREC. Movement of water into the canal is tidally influenced. At the mouth of the canal, current velocities ranged from 0.6 to 2.6 feet per second (fps) when last measured in 1983-1984.

Studies have demonstrated that in order to reduce Owner's total fuel cost, increased efficiencies can be realized from technological advancements and system modifications to increase generation capacity from the company's lowest cost fuel source. Following Owner's request, the Florida Public Service Commission (PSC) has determined that a power uprate is an economical option to add capacity and power output to the existing nuclear unit, CR3. The CR3 Uprate Project will result in economic benefits to customers and the community by providing additional clean energy at lower cost to consumers. An increase in the plant's gross output from 900 MW to 1,080 MW can serve the equivalent of an additional 110,700 homes.

The CR3 Extended Power Uprate (EPU) Project will occur over two phases. The first phase (Phase I) will occur during a 2009 planned refueling outage and scheduled steam generator replacement. The improvement to the turbine center line components will increase the efficiency of power production resulting in decreasing consumer costs. The second phase will result in an additional 140 MW of power and will require a large number of smaller yet substantial modifications to assure long term reliability of all plant systems at the conditions necessary to support a higher licensed power level.

The work identified in this statement of work (SOW) is to obtain the services necessary to design, procure, and construct (as identified below) the necessary Discharge Canal cooling equipment to mitigate the increased thermal heat rejected into the Discharge Canal by CR3 and to replace the heat removal capacity of temporary cooling equipment.

DESCRIPTION OF WORK – GENERAL

Owner requires Contractor to design and develop, procure, and construct the New EPU Cooling Tower as defined below so as to provide a minimum of 2.33 B BTUs/Hr heat removal from the Discharge Canal water prior to the water's return back to the Gulf of Mexico as identified below. The heat removal is required in order keep the water temperature below the NPDES three hour rolling average limit of 96.5^{0}F. The Design Criteria Manual and associated specifications, calculations, modeling, studies, and drawings were generated during the Study Phase of this Project. Contractor shall update the Study Phase conceptual design documents such that they will become the final design documents to be used for the Project's procurement of materials and construction.

The Work is broken down into work tasks. For this Work Authorization, Contractor shall perform Tasks 6a, 7a, 8a, and 10a, and the associated Work necessary therefore, including but not limited to Tasks 1, 2, 3, and 4. Task 5a will be performed by a different vendor under a separate contract. However, this task is included in this Statement of Work to provide clarification and guidance relative to Contractor's necessary interfaces and the information Contractor will be required to provide to Owner and the vendor performing these other tasks.

The major tasks are stated below. Details of each work task are provided in Section 3 of this document, in the Design Criteria Manual, and in the appropriate specifications.

- <u>New EPU Cooling Tower</u> – This scope includes engineering, procurement, construction of the EPU cooling tower, & startup testing. Performance testing will be done by an independent third party under a separate contract. The cooling tower Contractor will support the performance testing. The cooling tower is defined as the support structures and associated equipment attached to and located above the cooling tower cold water basin. The cooling tower is further detailed in Section 3 of this document, the DCM, and Specification S2a, incorporated herein as Exhibit 5 of this Work Authorization.

    - The boundary of the EPU cooling tower is at the cold water basin. The Contractor completing the cooling tower must:

        - provide the engineering detail for each interface point of the cooling tower with respect to the cooling tower basin,
        - complete the mechanical work up to and including the first flange off the cooling tower,
        - the first flange connection includes the flange, gaskets, and isolation valve and operator,
        - complete all the design, procurement and construction for low voltage electrical (<u><480</u> v circuits) components, including wiring terminations at the first electrical panel off the cooling tower (including providing and installing the first electrical panel off the cooling tower),

        - complete all the design & procurement specifications for electrical work supporting high voltage (≥ 480 v circuits) components located on the cooling tower. The cables to the high voltage equipment will be pulled to the cooling tower and terminated at the equipment by the intake structure work scope.
        - complete the design, procurement and construction of all support systems located on the cooling tower (i.e. lighting, etc.).
    - Complete the design for monitoring and controls of cooling tower fans, pumps, and related equipment.

- <u>**EPU Cooling Tower Basin & Foundations**</u> -- The scope of this work is to engineer & design the new EPU cooling tower cold water basin and foundations as defined below. Construction will be completed under a separate contract. The detailed requirements for this work are stated in Section 3 of this document and the DCM. The basin and foundations are defined as all concrete components and structures necessary to support the installed cooling tower and to facilitate proper hydraulic operation of the cooling tower system. The technical requirements for this work include:

    - Design of the basin and foundations subject to the following boundary conditions:
        - the Contractor that is awarded the basin and foundation design work will base his design on the cooling tower Contractor's loading diagram and mounting & support requirements. The design and engineering details of all interfaces between the cold water basin and the cooling tower structure will be developed by the cooling tower Contractor,
        - one physical boundary of this scope is up to and including the first flanged connection (with isolation valve & controls),
        - a second physical boundary of this scope is up to & including the first electrical box off the cooling tower maintenance area,
        - this scope includes the 40' maintenance area around the circumference of the cooling tower basin,
        - the cooling tower basin height will be adequate to allow gravity drain back to the Discharge Canal.
    - the cooling tower and basin design will allow for easy access and cleaning of marine growth from the basin and cooling tower structural members.
    - maintenance area (approximately 40' perimeter around the cooling tower basin),
    - electrical and instrumentation panels, conduits, cable trays, supports and restraints, for components mounted on the cooling tower basin or maintenance area,

- the design will include appropriate maintenance handling equipment and systems,
- some geotechnical soil characterization has been done by Owner. The Contractor is responsible for reviewing this information and finalizing the characterization as necessary to complete the cooling tower design.

- **<u>Intake & Discharge Structures</u>** – The scope of this work is to engineer & design the intake and discharge structures. The scope of work for the intake and discharge structures are further detailed in Section 3 of this document, the DCM, and specifications for equipment within this scope of work (i.e., S-4 – Trash Racks & Traveling Screens, S-5 Concrete, S-6-1 Fiberglass Reinforced Piping, S-6-2 – HDEP Piping, and others). The boundary of this task is defined as follows:
  - Design requirements and drawings of termination detail for high voltage cables on the cooling tower equipment,
  - Design requirements and drawings of termination detail for low voltage wiring at the first panel off the cooling tower,
  - Design of cable and wire ways to the cooling tower basin and to the cooling tower,
  - Design requirements and design for electrical power from the substation to the distribution center in the intake structure,
  - Design requirements and design detail of instrumentation and controls to the Unit 1 / 2 control room DCS.
  - Piping to and from the cooling tower basin,
  - The scope of this work also includes all geotechnical sampling required to complete the final design of the intake and discharge structures.

- **<u>Monitoring & Control Software & Hardware</u>** – The scope of this work is to design and develop the software and hardware for the equipment monitoring and control system for the new cooling tower equipment. The monitoring and control system must be compatible with the existing cooling tower Distributed Control System (DCS). The features of the monitoring and control system must be similar to the existing equipment. The Contractor will work closely with Owner personnel in completing this work.

The Contractor will provide the technical and engineering expertise to design and develop the procurement specifications for the cooling equipment and systems identified above and further described in section 3 of this document and in the Design Criteria manual.

The Contractor will develop & implement the associated calibration and test procedures to demonstrate proper equipment capabilities during equipment and component startup.

The Contractor will supply all management, supervision, labor, equipment, materials, tools, consumable supplies, and each and every item necessary to perform the Work describe in this Work Authorization.

The Contractor will perform both on-site and off-site activities necessary to complete the stated design and develop procurement specifications.

On site activities require preapproved access. The Contractor will submit site access forms 48 hours before expected CREC access unless otherwise approved by the Designated Representative.

The result of this Work Authorization will be the final design for the installation and operation of Discharge Canal cooling equipment that provides a minimum of 2.33 B BTU/Hr of Discharge Canal heat removal.

DESCRIPTION OF WORK – SPECIFIC

The design criteria for this section is contained in the Design Criteria Manual (DCM) included in this Work Authorization as Exhibit 6. The Contractor will maintain the DCM up to date as the final design is completed.

The Contractor will design the equipment and systems described below. The Contractor will also review and update the specifications for all the project materials. New specifications may be required to be generated by the Contractor to meet this requirement. The Contractor will also generate a list of potential vendors for each specification.

Task 1 Update and Maintain the Design Criteria Manual

The Design Basis of the DCM must be updated and maintained as the engineering design and procurement specification generation is completed. This task is a component of tasks 5 through 10.

The Design Basis was developed from information evaluated during the Study Phase of the Project. During the Project's Study Phase two important activities were completed. First, an Alternatives Analysis was completed. The Alternatives Analysis identified potential thermal mitigation technologies that could be used to reduce the thermal energy of the Discharge Canal water. The Alternatives list was then narrowed to the technologies that could be used at Crystal River. The technologies were then run through heat balance modeling to determine the optimal solutions and to provide a recommendation for further development in the second Study Phase task (conceptual design). The conceptual design further refined the alternatives analysis decision, defined the location of the cooling equipment, identified the equipment support utilities, stated the design standards for further design, developed design specifications for long lead items, and generated conceptual design drawings.

The Design Basis contains the Project's Design Requirements Section. The other DCM sections are developed based on the Design Requirements. As the final design evolves, the Contractor must revise the DCM Design Basis to maintain the design requirements in line with the current project directions.

Task 2 Update & Maintain Procurement Specifications

The Project Specifications of the DCM must be updated and maintained as the engineering design and procurement specification generation is completed. This task is a component of tasks 5 through 10.

The DCM also contains the Project's draft procurement specifications for long lead items. The procurement specifications for items identified as long lead were drafted during the study phase. The Contractor must update the long lead procurement specifications as soon as is feasible and identify potential vendors for each specification.

Task 3 Update & Maintain Project Design Drawings

The Project Drawings (contained in the DCM) must be updated and maintained as the engineering design and procurement specification generation is completed. This task is a component of tasks 5 through 10.

The Project drawings of the conceptual design are currently attached to the DCM. These drawings are to be revised and new drawings added during the final design effort.

Task 4 Provide Construction Guidelines & Test Procedures

The Construction Guidelines and Test Procedures (to be contained in the DCM) must be updated and maintained as the engineering design and procurement specification generation is completed. This task is a component of tasks 5 through 10.

All the construction guidelines, test procedures and special instructions generated for and implemented for the construction effort are to be maintained in the DCM. The construction guidelines and special instructions will be revised by the Contractor as the final design is completed.

Not Used

Task 5a Design & Construct the EPU Cooling Tower & Update Calculations (Clarifier Pond)

The Contractor must comply with specification (S2a) and the below requirements in designing and constructing the EPU cooling tower. The Contractor will update design calculations (C2 & C2a) in completing this work. The cooling tower specification incorporates the design requirements for the EPU cooling tower. The desired mechanical draft cooling tower design requirements are summarized as follows:

- complete tasks 1 through 4 as they relate to this task,
- revise specification S-3 – lift pumps, as an early task,
- the cooling tower will be a circular counterflow multi-fan design,

- the cooling tower will be located where the percolation clarified pond is now located,
- the cooling tower will provide a minimum heat rejection capability of 2.33 BBTU/Hr at an approach temperature of 11.0°F to an ambient wet bulb temperature of 79.0°F and a flow capacity of 320,000 gpm.
- the cooling tower fill is to be splash or trickle fill material that provides for easy maintenance and reliability,
- the cooling tower will have drift eliminators that limit drift to $\leq$.0005%,
- the construction material will be concrete with corrosion resistant coated rebar or pultruded composite FRP with high strength stainless steel fasteners or other material that withstand the harsh saltwater environment over a 30 year operating life,
- individual cooling tower fan cells must be capable of being taken out of service without shutting down the remainder of the cooling tower (isolation of air and water to individual cells)
- the cooling tower and maintenance area must fit within the area currently occupied by the clarifier pond and adjacent roads. The adjacent roads will become part of the maintenance pad around the new cooling tower.
- fans will be monitored and normally controlled from the control room,
- fan local operation will available for fan testing,
- local and remote control room monitoring instrumentation will provide operating status, fan current, fan vibration, bearing temperature, motor temperature,
- fan local instrumentation will have operating status motor & fan oil level,
- local and remote control room instrumentation for equipment controls will provide operating functions for the cooling tower pumps, fans, and valves,
- the cooling tower will be supplied with visual observation ports to observe the cooling tower fans,
- the cooling tower and basin must be designed to provide easy access for cleaning of marine life from the basin and cooling tower structural members,
- cooling tower riser isolation valves will have 480 volt motor operators. The valves will normally be remotely controlled but will be capable of local and manual operation,
- the cooling tower will have a walkway that allows personnel access to the cooling towers inter ring header area from grade level,
- the cooling tower will have a permanent personnel walkway access to the spray nozzles for maintenance and inspection,
- the cooling tower will have personnel access to one of the cooling tower cells for thermal performance monitoring,

- o the cooling tower will have an internal ring header to direct water to the cooling tower risers. The ring header (provided with this scope of work) will mate with supply header piping and flanges installed by another Contractor.
- o the cooling tower will have a fire detection system that reports back to the remote control room.

Not Used

Task 6a Design the EPU Cooling Tower's Basin and Surrounding Laydown Area (Clarifier Pond Location)

The Contractor will complete the cooling tower basin scope as follows:

- o Complete tasks 1 through 4 for the affected sections, related to this task.
- o Subsurface Investigation - All soil investigation work shall be the responsibility of the Contractor
  - Borings in soil, recovery of samples, tests on samples, or other soil investigations and exploratory procedures shall be performed as necessary for the design and construction of the EPU cooling tower foundations.
  - The number and size of soil samples, the methods of obtaining samples, and the field and laboratory tests and records for determining and recording the soil data shall be those that are usual and customary in the field of foundation engineering and are necessary and appropriate for the safe design of the foundations. As a minimum, the soil parameters that affect the stiffness and lateral load capacity of the deep foundation components shall be determined and strength and settlement parameters shall be determined for the design of foundations on soil.
- o Cooling Tower Site Preparation
  - Contractor shall prepare the cooling tower site, providing backfill, excavation, grading and compaction as required to stabilize the sites.

Basin Outlet Structure -

- o The cooling tower cold water basin shall be a watertight structure. The height of the cooling tower basin and outlet structure curb shall be sufficient to prevent splash-over during normal operation. Water stops shall be installed at all construction and expansion joints to prevent leaks. Contractor shall have a geotechnical survey performed to establish foundation requirements.
- o The cold water basin shall be designed for control of cracking. The average calculated crack width under service conditions shall not exceed 0.013 inch. The average crack width shall be computed from:
  - $W = 0.076 R f_s \sqrt[3]{d_c A}$

  where:

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W = The average crack width in units of 0.0001 inch
R = Ratio of distances to the neutral axis from the extreme tension fiber and from the centroid of the tension reinforcement
f_s = Calculated stress in the reinforcement at service, ksi (including temperature and shrinkage loads)
d_c = Thickness of concrete cover measured from the extreme tension fiber to the center of the bar located closest thereto which is perpendicular to the crack
A = $2d_c$ times the spacing of the reinforcement

Basin Foundation –

- The foundations for the EPU cooling tower shall be completely suitable for the structure, the loads, the subsurface conditions and the service.

- Foundation settlements shall be investigated and their effects provided for in the structural design and in the construction details.

- If piling is to be used for the basin, fill, and water distribution system foundations, at least one satisfactory load test shall be made for each size pile at each tower location.

Construction Guidance

- Forms shall conform to the lines and dimensions called for on approved Contractor's drawings. They shall be substantially and properly braced and supported so as to maintain their position during thorough compaction of the concrete with internal vibrators and shall be sufficiently tight to prevent leakage of water.
- No construction load shall be supported upon, nor any shoring removed from, any part of the structure under construction until that portion of the structure has attained sufficient strength to adequately support its weight and the loads placed thereon.
- Forms shall be removed and reset in such a way as to avoid damage to the concrete and to avoid disturbing reinforcement projecting above any concrete section to such an extent as to break the bond between this reinforcement and the recently placed concrete.
- Forms shall be designed to permit uniform spacing of horizontal and vertical joints where practical.
- Forms for exposed surfaces shall be such as to provide a smooth plane concrete surface equivalent to rough or board form finish as specified in Section 10.2 of ACI 301.
- gravity return of cooled water to the Discharge Canal,
- cooling tower basin allows for easy access and maintenance for marine growth removal

- o relocate electric utility as necessary to provide for safe construction and maintenance, Owner will provide direction for new routing,
- o the maintenance area has a minimum of 40' width surrounding the cooling tower basin to the edge of the paved maintenance area,
- o the maintenance area will provide for traffic around the cooling tower when maintenance is not being performed,
- o a retention wall will be designed to maintain the necessary separation from the percolation pond and the cooling tower area however the wall will allow for the necessary over flow from the percolation pond,
- o the percolation over flow will be directed around the cooling tower basin to the Discharge Canal, Task 8a will direct the water from the cooling tower basin to the discharge structure,
- o the Contractor will include a storm water run-off design that maintains the existing storm water collection basin (east of the cooling tower) operational. The storm water will be collected and pumped to the percolation pond system,
- o the cooling tower basin designwill include pipe support saddles, tie down straps, for a water supply ring header to be supplied and installed by the cooling tower Contractor, the support saddles will be constructed on a concreted pad within the cooling tower basin.

Not Used

Task 7a Design Intake Structure and Related Systems (Clarifier Pond Location)

The Contractor must use the conceptual design information in the DCM & complete the design of the intake structure and related equipment and systems for the cooling tower. The following is a summary of the intake structure design requirements:

- o Complete tasks 1 through 4 for the affected sections, related to this task.
- o The intake structure will be located on the discharge canal just north of the cooling tower,
- o This task will develop procurement specifications (many draft specifications are drafted and need to be completed/updated) for all the material required to support this task.
- o Defined as the intake structure on the Discharge Canal and the piping (with valves, expansion joints, restraints, and supports) between the intake structure and the cooling tower basin. This scope includes items listed below.
- o The physical structures at the discharge canal,

- o The maintenance and equipment handling equipment required off the cooling tower maintenance area (i.e. breaker handling removal, traveling screen removal, pump maintenance & isolation).
- o The piping fill & priming system,
- o The AC electrical system from the CREC substation to the electrical transformers, through the electrical distribution panels, and to the equipment or to the first electrical panel off the cooling tower maintenance area (including ETAP analysis),
- o The DC electrical system,
- o The instrumentation monitoring & controls system from the equipment or the first instrumentation panel off the cooling tower maintenance area, back to the local and remote control rooms,
- o The local area lighting,
- o Service water system,
- o Compressed air system,
- o the intake structure will have dual flow traveling screens to filter the water, one traveling screen for each lift pump, the traveling screen will have:
  - through screen velocity of < 0.5 feet per second flow at mean tide level,
  - Local and remote control room operation functions (primary operation will be from the remote operating console),
  - Control room instrumentation that indicates operating status, operating current, lift pump intake temperature, and differential screen pressure,
  - Local instrumentation that includes operating status, operating current, and differential screen pressure, and visual observation window to view the traveling screen surface. (see DCM for additional requirements),
- o the intake structure will have a dual flow traveling screen wash system,
  - the screen wash system will be operated remotely with the capability of local operation,
  - the screen wash system will have appropriate wash material handling equipment, return piping, baskets and containers,
  - screen wash system instrumentation will include pump operation status & spray header pressure,
- o the intake structure will have lift pumps (the number and size to be calculated by the cooling tower Contractor), the lift pumps will:
  - normally operate 3 to 4 pumps that have the capacity to provide the total amount of cooling tower flow,

- have excess lift pump capability that can supply 100% backup capacity of normally operating lift pumps,
- be normally operated from the control room but have remote operation capability for testing,
- Configured with instrumentation to remotely monitor bearing temperatures, motor temperature, motor current, and pump flow.

- The Contractor's intake structure design will have a weather enclosed and climate controlled housing for transformers & electrical switchgear and distribution panels, the enclosure will have breaker handling equipment, adequate lighting and room to properly maintain the switchgear. The height of the electrical equipment will be above the storm surge level or otherwise protected.
- The design for this task will include all the electrical equipment procurement specifications, installation details, electrical single line drawings, schematics, and other design documents needed to power all the equipment installed for the cooling tower, intake structure equipment and related system systems.
- The Contractor's design will also include piping, pipe supports, and restraints between the cooling tower and the intake structure.
- The water supply to the cooling tower will terminate internal to the cooling tower basin with flanged connections designed to attach to the cooling tower ring header.

Not Used

Task 8a Design Discharge Structure and Related Systems (Clarifier Pond Location)

The Contractor must use the conceptual design information in the DCM & complete the design of the Discharge Structure for the cooling tower. The following is a summary of the Discharge Structure design tasks and requirements:

- Complete tasks 1 through 4 for the affected sections, related to this task.
- The design Contractor will develop a design and cost estimate for piping and supports from the cooling tower basin to the discharge canal structure located west of the Helper cooling tower intake structure.
- The Contractor's discharge structure design will return flow in such a manner that the water will not be entrained with the HCT intake water,
- this design will include the piping, valves, and supports for piping returning water to the discharge canal, the design will be such that the construction and final installation will not interfere with site traffic.

- o The design must be to return the water such that the water will not erode the canal bank at the local point of discharge or further along the canal flow path.
- o The design will include incorporation of flow from the percolation pond over flow from the cooling tower basin to the discharge structure.
- o The design for this task includes development of a system to help predict the POD temperature as an operator aid.

Not Used

Not Used

Task 10a Design Software & Hardware to Interface with Existing DCS (Clarifier Pond Location)

The Contractor will develop software and hardware as necessary to allow local and remote monitoring and control of the new equipment installed by this Project.

- o Complete tasks 1 through 4 for the affected sections, related to this task,
- o To the extent possible the software and equipment should be off the shelf material,
- o The monitoring and control display should look and have the same type of control feel as the existing equipment,
- o The control system will be for all the newly installed equipment and systems

Not Used

Special Requirements

The Discharge Canal cooling equipment being designed and constructed for this effort will be in a harsh salty environment. The materials of construction must be corrosion resistant in this environment. For example; exposed metal will be monel or 316 stainless steel, & rebar will be coated steel. Other exposed material will be UV protected pultruded composite FRP or equivalent. Electrical distribution equipment should be protected by placing it in an environmentally controlled facility.

The Contractor will identify potential vendors for procurements. The Contractor will identify all the material handling equipment and equipment short term storage requirements.

Organizational Interfaces

The Contractor shall interface with various Owner organizations through the Owner Designated Representative (or designee) as identified in the organization chart and work process plan.

The Contractor will complete the engineering design and provide specific instruction to tie-in new equipment and systems to existing CREC systems. The Contractor will also develop test instructions for component functional testing, startup testing, and performance testing.

Owner Furnished Materials and Equipment & Work Included

The following materials and equipment will be furnished by Owner at no cost to the Contractor:

Owner has obtained subsurface characterization and geotechnical testing of the proposed cooling tower location. This information will be provided to the Contractor.

The Contractor is responsible for verification that all procurement specifications are adequate and that they will obtain the correct equipment needed for the project. The Contractor's verification of procurement specifications will be completed during the first 4 months of the engineering phase.

Site Conditions and Known Hazards

The Crystal River Energy Complex (CREC) is an industrial facility with continuing operations other than this project. Potential Hazards associated with this Project are as follows:

- The work area is within a security area. Un-escorted access to the work area requires facility specific training and an authorization badge.
- There are several other projects and operations that will have activities continuing in parallel with this project. Due to the number of site activities the traffic on the CREC facility and nearby areas will make traffic to and from the work area a hazard.

TECHNICAL REQUIREMENTS AND ACCEPTANCE CRITERIA

The Work to be completed as a part of this Work Authorization is defined in Section 3 of this document and in the Design Criteria Manual. The Design Criteria Manual (DCM) will contain the design requirements that are to be used as the project's final design documentation. The design documents will contain construction implementation requirements and standards. Equipment and component specific requirements have been rolled into the drafted procurement specifications attached to the DCM. The DCM will be expanded by the Contractor, during the final design work, to become the design basis document for the Project. The documents generated for and contained within the DCM will become the Project's construction documents.

The scope of the DCM covers all the design elements of the project. The DCM will be expanded from the design basis requirements during the final design and will house all the procurement specifications, engineering calculations, and drawings for the project.

The design criteria manual is divided into 8 design sections and three major Attachment sections as described below:

- Section 1 – Introduction and Plant Description
- Section 2 – General Design Criteria
- Section 3 – Architectural, Civil, and Structural Design Criteria
- Section 4 – Electrical Design Criteria
- Section 5 – Instrumentation and Controls Design Criteria
- Section 6 – Mechanical Design Criteria
- Section 7 – Plant Design Criteria
- Section 8 – Environmental Design Criteria

- o Attachment 1 – Procurement Specifications and design calculations
- o Attachment 2 – Project Drawings
- o Attachment 3 – Construction Guidelines anc test procedures

Design Interfaces

The design will potentially interface with the following CREC site systems and additional Project personnel:

- o Electrical substation
- o Electrical building and switchgear at the HCTs.
- o Unit 1 Control Room DCS and DCS remote consoles in CRS Main Control Room and existing HCT control room,
- o Waste water piping from Unit 1, 2, & 3.
- o Potable water system
- o Electrical distribution (4.16 KV, 480 V, & 120V, etc.) local to the work facilities
- o Telephone distribution system
- o The design implementation will require obtaining CREC Operations personnel input.

The design requirements are well defined in the Design Criteria Manual with the exception of the following.

- o Equipment monitoring, controls, and display functions. The Contractor will work with Owner's personnel in developing the hardware and software to communicate and interface with the existing Distributed Control System (DCS). The new indication and controls must look and operate similar to the existing control room equipment.
- o Additional electrical power will be distributed from the onsite electrical substation. The specific design of the modifications will require close work with the Progress Energy Florida (Owner) Transmission Group. The Owner Transmission Group will design and modify the substation equipment. The Contractor's designed equipment will tie into the substation provided disconnect. Owner Transmission will make the final tie-in at the CREC substation. The Contractor will re-do the ETAP analysis as part of the final design.
- o Another design and construction interface is with PMI Ash. PMI Ash loads ash from the southeast tank and transports the ash to another location. A transportation route will need to be maintained open by the Contractor during the construction of the cooling tower. The design for the cooling tower basin and cooling tower must make provisions to maintain PMI Ash transportation capabilities.
- o The access around the construction site will also be used by other CREC operations for;
    - Security Patrols,

- Access to percolation ponds,
- Access to maritime transportation security administration offices,
- And others.

Codes and Standards

Unless specified otherwise, the current edition or revision of the code in effect on the date of award shall be used. Applicable codes and standards have been identified in the DCM and draft specifications.

Specifications

Specifications for several of the long lead items were drafted during the conceptual design phase of the project. The Contractor is responsible for validation of the specifications as an early part of this work (within 4 months of NTP). The long lead items will then be procured in parallel with completing the final design.

The draft specifications are located in the DCM. New and revised specifications are to be maintained as part of the DCM by the Contractor.

Drawings

The drawings included in the DCM are hereby incorporated into, and made a part of this Work Authorization. The drawings will be revised as necessary to reflect the final design. New drawings shall be made part of the DCM by the Contractor. Site drawing will be updated by the Contractor to indicate the new installations and equipment modifications.

A. Bidder shall submit with his bid general arrangement drawings; descriptive information covering the design and site layout of the EPU cooling tower, inlet header piping, cold water outlet connections, and ancillary equipment; and an equipment list including manufacturer and model numbers.

B. After Work Authorization award, Contractor shall submit five copies of each drawing and associated installation and removal instructions to Owner. Drawings and installation / removal instructions submitted to Owner shall be of a quality such that they will be capable of yielding hard copy reproductions with every line, character, and letter clearly legible and useable for further reproduction. Copies of the electronic files for all CAD drawings shall be submitted in AutoCAD Version 2006. Electronic copies of all project drawings shall be submitted to Owner.

C. All submittals of drawings and installation instructions shall include identifying information such as the Specific Plant Name, Specification number, drawing subject, and drawing number / revision, and the intended use, i.e. "For Construction" or "For Comments", or "For Reference", etc. The intended use shall also be specified on the transmittal letter.

D. All design drawings and data shall be submitted to Owner for review. Drawings and data submitted for review shall be complete in all respects and thoroughly checked by the Contractor. Drawings that are reviewed by Owner will be returned, properly noted with respect to their status for fabrication / construction; comments shall be incorporated and drawings and data shall be resubmitted to Owner.

E. All design drawings shall be stamped by a Professional Engineer registered in the State of Florida or by a Structural Engineer licensed in the State of Florida as appropriate.

F. All drawings prepared by the Contractor for this project shall become the property of Owner.

G. All drawings shall follow Owner's numbering scheme.

H. All equipment, pipes, valves, junction boxes shown on the drawings shall be labeled on the drawings with identification numbers supplied by Owner.

I. Drawings shall depict information appropriate to its division:

1. Mechanical (including general arrangement, schematic, and physical drawings)
2. Electrical / Instrumentation / Controls (including schematics, logic diagrams and physical drawings, P & ID)
3. Civil / Structural

J. An original copy of all calculations needed for completion of the design shall be submitted to Owner for review. Any comments from Owner shall be resolved by the Contractor prior to final acceptance by Owner.

K. Vendor manuals for all supplied equipment shall be submitted to Owner "For Record". Five copies shall be submitted. Vendor manuals shall include a list of recommended preventive maintenance practices and a list of spare parts for the EPU cooling tower.

Exhibits

The Project's Phase 1 Alternatives analysis and related information will be made available to the Contractor as requested.

The Project's Phase 2 Conceptual Design Report and related information are available with this Work Authorization.

Electrical Safety Requirements

1. All electrical equipment and industrial control panels delivered or brought onto the site in performance of this Work Authorization must be labeled by an OSHA approved nationally recognized testing laboratory (NRTL).
2. All electrical equipment installed as part of this Work Authorization must comply with the National Electric Code (NEC), NFPA 70 and where applicable ANSI C2 (NESC). The Buyer reserves the right to inspect electrical equipment and installations. Contractor is responsible for notifying Owner when installations are available for inspection.
3. Electric motors shall be labeled to be in accordance with NEMA MG-1 or listed by an OSHA approved NRTL.
4. Electrical equipment and devices for which there is a NRTL listing category must be Listed or Labeled by UL or another OSHA approved NRTL.
   a. The Canadian Standard Association (CSA) is not a recognized OSHA approved NRTL marking unless the label includes "US" or "NRTL".

b. The European Union CE Markings Directive 93/68EEC is not a recognized OSHA approved NRTL marking.

c. The International Electrotechnical Commission (IEC), IEC Standard 60529 for enclosures (IPxx), is not recognized as an acceptable OSHA approved NRTL label.

Electrical equipment for which there is no listing category must be evaluated or tested using a method submitted to and approved by Owner prior to delivery of the equipment.

Electrical equipment is also subject to the "Counterfeit Suspect Item Program."

Hoisting and Rigging Requirements

The Contractor will identify any special hoist or rigging requirements associated with the designed equipment.

Fire Prevention Requirements

No fire prevention system is expected to be required however; the final design will determine the need for fire prevention systems.

Acceptance Criteria

The DCM identifies the engineering and design functions that will need to be completed as a part of the work for this Work Authorization. In addition, the final design, as required by the DCM, will conclude with providing a statement of Construction instructions. The final design documents (including: procurement specifications, Project drawings, and construction instructions) will be used by the Contractor to install the necessary Discharge Canal cooling equipment and support systems.

1.1.1 Acceptance Criteria for Task 1 - Update & Maintain the DCM as the engineering design & procurement specification generation is completed.

- The Contractor will provide a Design Construction Manual that contains a design basis section that:

  A. Identifies the systems to be installed by the project,

  B. Identifies the major components and equipment to be installed by this Project,

  C. Provides the system requirements for each of the systems installed for the project,

  D. Clearly identify the component design requirements for all the components installed for this Project.

  E. The DCM will reflect the final design & as built conditions of the modified & newly constructed equipment & systems.

1.1.2 Acceptance Criteria for Task 2 – Procurement Specifications & Design Calculations

The Contractor will update the cooling tower specifications and update the other specifications as necessary. The specification will then be provided to Owner with proposed vendors as part of this effort. The acceptance criterion for this work is the development of specifications and support calculations that contain the correct design requirements for the equipment and systems.

1.1.3 Acceptance Criteria for Task 3 – Project Drawings

The Contractor will update the cooling tower drawings and generate new drawings as necessary to support the installation of the Project's equipment and systems. The drawings must be in enough detail to complete the construction as detailed in other sections of this document.

1.1.4 Acceptance Criteria for Task 4 – Construction Guidelines & Test Procedures

The Contractor will provide support information to clarify construction requirements. The Contractor will develop startup, functional testing, and performance test procedures to safely place the constructed equipment & systems into service. The Performance testing is to be completed by a third party.

1.1.5 Acceptance Criteria for Task 5a - The Contractor must use the conceptual design information in the DCM & related specification to complete the design and construction of a cooling tower that meets the design requirements provided in the DCM & section 3 of this document. The cooling tower must meet the performance requirements identified in Specification S2a as appropriate.

1.1.6 Not Used

1.1.7 Acceptance Criteria for Task 6a – The Contractor must use the conceptual design information in the DCM & Related specification to complete the design and related procurement specifications for the cooling tower basin on which the cooling tower is built and laydown/maintenance area around the cooling tower that meets all the requirements of section 3.0 of this document

- The cooling tower basin adequately supports and matches up with the cooling tower structure,
- The cooling tower basin has the capability to direct both cooling tower basin and percolation pond over flow to the Discharge Canal,

- o The cooling tower basin & percolation pond over flow gravity drain into the Discharge Canal,
- o The cooling tower basin allows for easy access and maintenance for marine growth removal,
- o The maintenance area surrounding the cooling tower is 40' wide,
- o The maintenance area will provide for traffic around the cooling tower when maintenance is not being performed.
- o The design incorporates collection and handling of the storm water run-off from the area during construction and operation.

1.1.8 Acceptance Criteria for Task 7a - The acceptance criteria for this task is to design an intake structure that meets all the requirements of section 4.0, the DCM procurement specification, and:

- o the intake structure will be located on the discharge canal just north of the cooling tower,
- o the intake structure will have dual flow traveling screens to filter the water, one traveling screen for each lift pump, the traveling screen will have:
  - ▪ through screen velocity of < .5 feet per second flow at mean tide level,
  - ▪ Local and remote control room operation functions (primary operation will be from the remote operating console), in the CRS Main Control Room,
  - ▪ Control room instrumentation that indicates operating status and differential screen pressure,
  - ▪ Local instrumentation that includes operating status, operating current, and differential screen pressure, and visual observation window to view the traveling screen surface. (see DCM for additional requirements),
- o the intake structure will have a dual flow traveling screen wash system,
  - ▪ the screen wash system will be operated remotely with the capability of local operation,
  - ▪ the screen wash system will have appropriate wash material handling equipment, and an appropriate wash water return configuration,
  - ▪ screen wash system instrumentation will include pump operation status & spray header pressure,
- o the intake structure will have 3 lift pumps (actual number to be designed as part of this task), the lift pumps will:

- normally operate two pumps that have the capacity to provide the total amount of cooling towers flow,
- have one lift pump that can supply 100% backup capacity of one lift pump,
- be normally operated from the control room but have remote operation capability for testing,
- Configured with instrumentation to remotely monitor bearing temperatures, motor temperature, motor current, and pump flow.

o the intake structure will have a weather enclosed and climate controlled housing for transformers & electrical switchgear and distribution panels, the enclosure will have breaker handling equipment, adequate lighting and room to properly maintain the switchgear.

1.1.9 Acceptance Criteria for Task 8a - The acceptance criteria for this task is to design a discharge structure that meets all the requirements of section 4.0, the DCM procurement specification, and:

o the discharge structure will be on the south side of the Discharge Canal

- return flow is to be directed such that the water will not be entrained with the HCT intake water

o the structure must be designed to return the water such that the water will not erode the canal at the point of discharge and mix with the Discharge Canal flow.

Not Used

1.1.10 Acceptance Criteria for Task 10 - The acceptance criteria for this task is to provide procurement specifications for all the required material and develop a delivery schedule that coordinates the material deliveries such that there is no impact on the construction schedule or other CREC activities.

Not Used

PERSONNEL REQUIREMENTS

Training and Qualification

1.1.11 Contractor shall ensure that the Contractor's personnel meet and maintain the appropriate training, qualification and certification requirements. CREC site-specific training requirements to safely perform this work are identified below.

1.1.12 The following training is required:

- CREC general access training,
- Project specific indoctrination for safety and Project Management,
- Contractor job specific training (to be identified with the specialized tasks to be performed),
- Occupational Safety and Health Administration (OSHA) Training.

1.1.13 CREC required site training will be coordinated through the Designated Representative (DR). Advanced notice (48 hours) must be given the DR to arrange this training. Required OSHA, and Job Specific Training shall be provided by the Contractor.

1.1.14 The required training shall be completed prior to work.

1.1.15 The Contractor must meet the following minimum qualifications:

1. A professionally licensed engineer in the State of Florida is required to approve all of the final design documents to be used for construction.
2. Experience in the areas of general and cooling tower construction. The Contractor will have > 15 years experience with work on similar type, size, and scope projects.
3. The Contractor's Key personnel must be dedicated to this project and cannot be transferred without Owner's DR approval. The following are considered Key Contractor personnel.
   - The Contractor's Project Manager must have > 10 years experience managing work on similar type, size, and scope of projects.
   - The Contractor's Engineering Manager must have > 7 years experience managing work on similar type, size, and scope of projects.

Security and Badging Requirements

A. The Contractor shall obtain at the Contractor's expense, facility clearance and security badges for employees prior to obtaining access to the job site.

B. Contractor employees will be required to: submit to vehicle searches, obtain tool and equipment permits prior to entering and leaving restricted areas, and to maintain hard hat markings.

C. A minimum of 2 days advance notice is needed for visitor badging. CREC badges will be processed for those needing continuous access to the site. Processing for the site access badge is approximately 2 weeks.

Site Access and CREC Work Hours

A. Work will be done on an 8-9's schedule. The standard work day shall consist of nine (9) hours of work between 7:00 AM and 4:30 PM, with one-half hour designated as an unpaid period for lunch, which may be taken between the hours of 11:00 AM and 1:30 PM, but not to exceed five (5) hours from the start of the shift. An eight (8) hour work day is substituted on alternate working Fridays, and no work occurs on the alternate non-working Friday.

B. The Contractor will have access to the job site from notice to proceed through August 30, 2009.

ENVIRONMENTAL, SAFETY, HEALTH, AND QUALITY REQUIREMENTS

The Contractor shall perform work safely, in a manner that ensures adequate protection for employees, the public, and the environment, and shall be accountable for the safe performance of work. The Contractor shall comply with, and assist the Buyer in complying with Environmental, Safety, Health, and Quality (ESH&Q) requirements of all applicable laws, regulations and directives.

The Contractor shall flow down ESH&Q requirements to the lowest tier subcontractor performing work on the CREC site commensurate with the risk and complexity of the work.

The Contractor shall evaluate Subcontractors in accordance with Owner procedure SAF-SUBS-00041 or similar process approved by Owner

Integrated Environment, Safety and Health Management System (ISMS)

The Contractor shall exercise a degree of care commensurate with the work and the associated hazards. The Contractor shall ensure that management of ES&H functions and activities is an integral and visible part of the Contractor's work planning and execution processes. As a minimum, the Contractor shall:

- Thoroughly review the defined scope of work;
- Identify hazards and ES&H requirements;
- Analyze hazards and implement controls;
- Perform work within controls; and
- Provide feedback on adequacy of controls and continue to improve safety management.
- Continue pre-job safety evaluations and implement adequate controls for new hazards as they are identified.

The Contractor shall address how the five bulleted items above will be implemented in the Contractor's Project Specific Health & Safety Plan (PHASP).

Environmental Requirements

1.1.16 Environmental responsibility is a core value of Owner. We are committed to excellence in our environmental practices and performance. The company acknowledges 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.

1.1.17 In accordance with this policy the Contractor shall prepare an Environmental Execution Plan which describes how the Contractor will comply with Owner's core value of environmental responsibility. The plan must identify the organizational structure responsible for implementation of the plan; how the plan is to be administered; how environmental information and reporting to Owner will be handled; how worker awareness and environmental training will be implemented; and what additional documents and/or plans will be attached to or referenced by the plan. Examples of these additional documents include but are not limited to: Spill Prevention Control and Countermeasures (SPCC) Plan, Storm Water Pollution Prevention Plan (SWPPP), Waste Management Plan (for hazardous, industrial, and special wastes), and a chemical and petroleum product storage and inventory plan.

1.1.18 Contractor is strongly encouraged to incorporate Pollution Prevention practices in the selection of all chemical products required for the project. The contractor must obtain pre-approval for all chemicals brought on site in accordance with the Nuclear Generation procedure CHE-NGGC-0045, Chemical Control Program. The chemical approval process must start as soon as possible and the Contractor should keep in mind that a week approval process may be needed for typical evaluations.

1.1.19 Any RCRA hazardous waste created as the result of project activity become the responsibility of the site. The contractor will be responsible for properly containerizing, identifying, and labeling such waste in accordance with RCRA regulatory requirements. Through proper adherence to pollution prevention practices and chemical control procedures the generation of hazardous waste should be greatly minimized or eliminated. It is Owner's expectation that the Contractor will identify and estimate the quantity of hazardous waste anticipated to be generated during the duration of the Project. Records of all hazardous and special waste (e.g., used oil) activities shall be maintained and provided to Owner at least monthly, and/or as requested.

1.1.20 Owner is responsible for obtaining all environmental regulatory permits necessary for construction of the project including: PSD Construction permit, Environmental Resource Permit, Florida NPDES storm water permit for construction activity, and Florida Industrial Wastewater NPDES discharge permit. The Contractor is responsible to provide the necessary engineering to support submittal of the permits in a timely manner that supports the Project's schedule.

1.1.21 The Contractor must incorporate the requirements of the Crystal River Site Manatee Protection Plan into any "in-water" work conducted in the site discharge canal. The protection is for work completed during the period November 15 through March 31.

Safety Requirements

A. The Contractor is required to submit a Project Specific Health & Safety Plan that identifies the potential hazards that may be encountered in completing this work scope. The PHASP procedures and processes will address the Owner procedures were applicable. For example the Contractor's Lock Out/ Tag Out process must be consistent with Owner requirements. The Contractor will revise the PHASP as necessary to include new hazards when they are identified. As applicable, the following topics will be covered in the PSHASP and comply with applicable OSHA standards.

a. INTRODUCTION AND TABLE OF CONTENTS

b. GLOSSARY

c. PROGRAM GENERAL REQUIREMENTS

d. RESPONSIBILITY, AUTHORITY, AND ACCOUNTABILITY

e. SAFETY RELATED DISCIPLINE

f. TRAVEL SAFETY

g. OFFICE SAFETY

h. EMERGENCY PREPAREDNESS

i. SAFETY AND HEALTH COMPLIANCE INSPECTION AND MANAGEMENT WALKTHROUGHS

j. ACCIDENT PREVENTION TRAINING AND EDUCATION

k. PREJOB SAFETY PLANNING

l. DRUG-FREE WORKPLACE/FITNESS-FOR-DUTY PROGRAM

m. EVENT INVESTIGATING AND REPORTING

n. CLASSIFYING AND RECORDING INJURY/ILLNESS

o. WORK HOUR CONTROL/WORKING ALONE

p. WORK RELEASE CONTROL

q. PERSONAL PROTECTIVE EQUIPMENT

r. FALL PROTECTION

s. HAZARDOUS MATERIALS AND FLAMMABLE / COMBUSTIBLE LIQUIDS

t. FIRE PREVENTION AND PROTECTION

u. HOUSEKEEPING

v. MOTORIZED EQUIPMENT PREOPERATIONAL AND PERIODIC INSPECTION

w. HOISTING AND RIGGING

x. ELEVATING WORK PLATFORMS AND AERIAL LIFTS

y. SIGNS, SIGNALS, AND BARRIERS

z. SAFETY SHOWERS AND EYEWASHES

aa. PORTABLE LADDERS

bb. SCAFFOLDS

cc. COMPRESSED GAS OPERATIONS

dd. MATERIAL HANDLING AND STORAGE

ee. MACHINERY AND MACHINE GUARDING

ff. HAND AND PORTABLE POWER TOOLS

gg. WELDING SAFETY

hh. CONTROLLING HOT WORK

ii. ELECTRICAL WORK SAFETY

jj. ELECTRICAL INSTALLATION SAFETY

kk. EXCAVATION, TRENCHING, AND SHORING

ll. CONCRETE AND MASONRY CONSTRUCTION

mm. DEMOLITION

nn. SAFETY COLOR CODING FOR MARKING PHYSICAL HAZARDS

oo. LOCKOUT/TAGOUT PROGRAM

pp. CONTROLLING ORGANIZATION'S CONTROL OF HAZARDOUS ENERGY

qq. STEEL ERECTION

rr. CONSTRUCTION AND MAINTENANCE EATING AND SANITARY FACILITIES

ss. WORKSITE FIRST AID

tt. FLUSHING AND PRESSURE TESTING

uu. INDUSTRIAL HYGIENE PROGRAM REQUIREMENTS

vv. HEARING PROTECTION

ww. HEAT STRESS PROGRAM

xx. LEAD CONTROL

yy. OCCUPATIONAL MEDICAL PROGRAM

zz. HAZARD COMMUNICATION

aaa. RESPIRATORY PROTECTION

bbb. INFECTIOUS DISEASE (BLOODBORNE PATHOGENS)

ccc. CONFINED SPACE ENTRY

ddd. OCCUPATIONAL ERGONOMICS

B. The Contractor's PSHASP must be approved by Owner prior to starting the work covered by that practice.

C. Chemical Management. If hazardous materials and/or chemicals (such as cements, grouts, lubricants, glues, adhesives, explosives, paints, solvents, cleaners and temporary fuel storage containers) will be brought on-site by the contractor in the performance of the work, these items will need to be tracked through the Owner Chemical Management Program using Attachment 2 of CHE-NGGC-0045, NGG – Chemical Control Program.

D. If the Contractor has more than one employee working on site in performance of this Work Authorization, the Contractor will identify a member of its staff as its "Designated Safety Representative." This individual must have the authority, responsibility and knowledge to identify and correct any unforeseen hazardous or unsafe conditions, acts or instances of noncompliance.

Quality Assurance and Control

A. Contractor shall be responsible for performing quality workmanship and shall conduct the quality control measures necessary to ensure work conforms to drawings and specifications.

B. Plans, procedures, and engineering documentation shall be controlled in accordance with the Contractor's and Lower-tier Subcontractor's Quality Assurance Program which may be reviewed by Owner.

C. Third party as referred in this document shall be a lower-tier subcontractor qualified per ASTM E-329, Agencies Engaged in the Testing and / or Inspection of Materials Used in Construction.

D. Owner reserves the right to make inspections at any time at the source of supply of materials.

E. All items and processes are subject to review, inspection or surveillance by Owner at the contractor's facility, or any lower-tier subcontractor's facility.

F. Equipment requiring calibration shall be periodically calibrated to assure reliable results.

G. Contractor shall be responsible for the performance of all inspection and testing activities as specified in the Contractor's submittal "Quality Assurance Inspection Plan," provided to Owner for approval within 30 days of Work Authorization award.

Quality Assurance/Inspection Requirements

A. Quality Assurance Program Submittal and Pre-Award Survey

The Contractor shall submit the quality assurance program requirements that are applicable to the implementation of the designed work. These requirements shall be in a format that can be included in the construction contract for this work.If the Contractor's manual has been previously approved by the Buyer, the manual shall be updated to make it current and resubmitted to Owner with the proposal. If the manual has not changed since its previous approval by Owner, a statement to this effect shall be submitted with the proposal. Owner shall evaluate the Contractor's Quality Assurance program prior to

Work Authorization award. This evaluation may include a survey of quality program implementation at the Contractor's facilities. If a program change is required, it will be identified to the Contractor prior to Work Authorization award. A deficient or inadequate program may be used as the basis to deny award of this Work Authorization.

The selected Engineering Contractor will identify the necessary level of quality control during the engineering design process and state QA/QC requirements on the applicable design and procurement documents. The following requirements will apply as identified during the engineering design process.

B. Supplier Quality Program Evaluation

When subcontracting any portion of this Purchase Order/Work Authorization, the Supplier is required to invoke the applicable quality assurance program requirements on the subcontractor.

Owner reserves the right to verify the quality of work at the Supplier's facility, including any subcontractor's facility. Access to a subcontractor's facility shall be requested through the Supplier and verification may be performed jointly with the Supplier.

The Supplier shall, during the performance of this Purchase Order/Work Authorization, submit proposed changes to the quality assurance program to the Contractor & Owner for review prior to implementation.

C. Nonconformance Documentation and Reporting

All nonconformances identified at the Supplier's facility with a proposed disposition of "Accept" or "Repair" shall be approved by the Buyer before any corrective action is taken by the Supplier on the nonconformance.

Accept: A disposition that a nonconforming item will satisfactorily perform its intended function without repair or rework.

Repair: A disposition requiring the processing of a nonconforming item so that its characteristics meet the requirements listed in the disposition statement of the nonconformance report.

Nonconformance shall be documented by the Supplier on the Supplier's nonconformance form or on an Engineering Procurement Waiver, which is provided by the Buyer. After documenting the nonconformance, disposition and technical justification, the form/waiver shall be forwarded to the Buyer.

After the recommended disposition has been evaluated by the Contractor & Owner, the form/waiver shall be returned to the Supplier with a disposition of approval or rejection. The Supplier may take corrective action on the nonconformance only after the form/waiver is approved.

The approved Engineering Procurement Waiver or Supplier's nonconformance form shall be shipped with the affected item.

D. Certified Welds & Inspectors

The Contractor is required to identify the weld and weld inspection requirements for this design. The weld requirements will be included on the appropriate drawings and in the construction guidelines.

E. Identification of items with Part number/Model Number

The Contractor is required to provide procurement and construction requirements to verify material by part number. The requirements will be in the procurement specifications and construction guidelines. For example - All items shall be identified with the part number/model number. Identification shall be on the item or the package containing the item. When the identification is on the item, such marking shall not impair the service of the item or violate dimensional, chemical, or physical requirements.

F. Identification of Items with Product Data Sheet

The Contractor is required to provide procurement and construction requirements for the supplier to submit a legible copy of the product data sheet (e.g., drawing, catalog page, brochure) that provides adequate information to enable the Buyer to verify the form and function of the article procured. One copy of the documentation, unless otherwise specified, shall accompany the applicable item(s) shipped. The requirements will be in the procurement specifications and construction guidelines.

G. Identification of Items

The Contractor is required to provide procurement and construction requirements for the items to be identified with the part number/model number. Identification shall be on the item or the package containing the item. When the identification is on the item, such marking shall not impair the service of the item or violate dimensional, chemical, or physical requirements. The requirements will be in the procurement specifications and construction guidelines.

The Supplier shall submit a legible copy of the product data sheet (e.g., drawing, catalog page, brochure) that provides adequate information to enable the Buyer to verify the form and function of the articles procured.

One copy of the documentation, unless otherwise specified, shall accompany the applicable item(s) shipped.

H. Identification and Traceability of Items

Where necessary the requirements for material traceability will be incorporated into the procurement specifications and construction guidelines. For example: All items shall be identified with the part, heat, batch, or serial number and the Purchase Order and line item number. Identification shall be on the item or the package containing the item. Where identification is on the item, such markings shall not impair the service of the item or violate dimensional, chemical, or physical requirements.

I. Identification of Age Control Items

The requirements for identification of age control will be in the procurement specifications and construction guidelines. For example: The Supplier shall identify each item, assembly, package, container, or material, having limited shelf life, with the cure date or date of manufacture and the expiration date. The Supplier shall specify any storage temperatures, humidity and environmental conditions which should be maintained. Material shall NOT be furnished having less than 75 percent of total shelf life available at time of shipment.

J. Liquid Penetrant Material Certification

The requirements for liquid penetrant material certification will be in the procurement specifications and construction guidelines. For example: A certification of contaminant content shall be furnished for each batch number of penetrant, cleaner, developer, and emulsifier provided. The certification shall include the test results which meet the requirements of ASME Section V, Article 6, and the latest mandatory addenda or Purchase Order/Work Authorization specified addenda. All materials and reports are subject to review and acceptance by the Buyer.

K. Certified Material Test Report

The requirements for certified material test reports will be in the procurement specifications and construction guidelines. For example: The Certified Material Test Report (CMTR) shall include actual results of all chemical analysis, tests, examinations, and treatments required by the material specification and this Purchase Order/Work Authorization. The CMTR shall be legible, reference applicable specification number and year of edition, and be traceable to the material furnished by heat or lot number. All reports are subject to review and acceptance by the Buyer.

The report(s) shall contain the Purchase Order/Work Authorization number and a description of the item to which the report applies. The report shall be signed by an authorized representative of the Company.

One copy of the documentation, unless otherwise specified, shall accompany the applicable item(s) shipped.

L. Inspection and Test Report

The requirements for inspection and test reports will be in the procurement specifications and construction guidelines. For example: The Supplier shall submit legible, reproducible copies of Inspection/Test Reports.

The report(s) shall include the following:

1. Identification of the applicable inspection and/or test procedure utilized.
2. Resulting data for all characteristics evaluated, as required by the governing inspection/test procedure.
3. Traceability to the item inspected/tested, (i.e., serial number, part number, lot number, etc.).

4. Signature of the Supplier's authorized representative or agency which performed the inspections/tests.

One copy of the documentation, unless otherwise specified, shall accompany the applicable item(s) shipped.

M. Flame Test Report

The requirements for flame test reports will be in the applicable procurement specifications and construction guidelines. For example: A flame test report shall be submitted. The report shall include the following:

1. Test procedure identification.
2. Resulting data as required by IEEE-383.
3. Traceability to the material tested (i.e., batch number, heat number, lot number).
4. Signature of the authorized representative or agency performing the tests. Reports shall also reference the Purchase Order/Work Authorization number.

One copy of the documentation, unless otherwise specified, shall accompany the applicable item(s) shipped.

N. Calibration Report

The requirements for calibration reports will be in the procurement specifications and construction guidelines. For example: Certification stating the equipment furnished to the Purchase Order/Work Authorization requirements has been calibrated utilizing standards whose calibration is traceable to the National Institute of Standards and Technology or other documented evidence must be submitted stating the basis of the calibration. In addition, the Supplier shall submit a report of actual calibration results. The report shall be identifiable to the acceptance criteria of the items submitted and shall meet Purchase Order/Work Authorization requirements. The report shall contain the signature of the authorized representative of the agency verifying compliance.

One copy of the documentation, unless otherwise specified, shall accompany the applicable item(s) shipped.

O. Certification of Calibration

The requirements for certification of calibration records will be in the procurement specifications and construction guidelines. For example: The Supplier shall submit legible, reproducible copies of Certificates of Calibration, which are traceable to the National Institute of Standards and Technology, for each article ordered. Each certificate shall be identified with:

1. The Buyer's Purchase Order/Contract Order number.
2. Identification of the article to which the certificate applies.
3. The standards used for calibration. Each calibration certificate shall be signed by the Supplier's representative that is responsible for the calibration to attest to its authenticity.

One copy of the documentation, unless otherwise specified, shall accompany the applicable item(s) shipped.

P. Repair and Calibration Services

The requirements for calibration and repair will be in the procurement specifications and construction guidelines. For example: When repair and calibration services are required, the Supplier shall perform the repairs in accordance with the manufacturer's instructions. The report of calibration shall include:

1. Actual calibration or test data
2. The as-found data or condition
3. As-left data (after repair and calibration, before leaving the Lab) if different than the as-found data
4. The scope and description of repairs completed or attempted, if applicable.
5. The instrument identification or serial number

The report shall be signed by the Supplier's authorized representative.

One copy of the documentation, unless otherwise specified, shall accompany the applicable item(s) shipped.

Q. Supplier Furnished Items

Suppliers shall obtain the items on this Purchase Order/Work Authorization directly from the original manufacturer. The supplier shall provide legible and reproducible documentation, with the delivery, that provides objective evidence that the items were provided by the original manufacturer. These may include the Purchase Order/Work Authorization to the original manufacturer, shipping documentation, or manufacturer invoice; each of which identifies the items obtained from the original manufacturer.

One copy of the documentation, unless otherwise specified, shall accompany the applicable item(s) shipped.

R. Control of Graded Fasteners

The requirements for control of graded fasteners will be in the procurement specifications and construction guidelines. For example: The provisions stated below are the minimum requirements for high strength graded fasteners produced in compliance with national consensus standards (e.g., SAE, ASTM, ASME).

1. Fasteners shall exhibit grade marks and manufacturer's identification symbols (headmarks) as required in the specifications referenced in the Purchase Order/Work Authorization.

2. Any fasteners supplied with headmarks matching those displayed on the attached Suspect/Counterfeit Fastener Headmark list, or facsimiles thereof, shall be deemed to be unacceptable under the terms of this Purchase Order/Work Authorization.

3. When requested by the Buyer, the Supplier shall provide a legible and reproducible copy of the manufacturer's Certified Material Test Reports (CMTR). These CMTRs shall report the values of the actual chemical and physical tests performed on the represented fastener lot/material heat. Fastener packaging/labeling shall be traceable by lot number or other positive means to the CMTRs.

4. Fasteners shall be inspected to verify compliance with the Purchase Order/Work Authorization requirements. Additionally, fasteners may also be subjected to destructive testing.

5. When requested by the Buyer, the Supplier shall provide a Certificate of Conformance which must certify conformance and traceability of supplied materials to the subject Purchase Order/Work Authorization. The document must be legible and reproducible.

S. Procurement of Potentially Suspect or Counterfeit Items

The requirements for procurement of suspect or counterfeit items will be in the procurement specifications and construction guidelines. For example: Supplier shall warrant that "all items furnished under this Purchase Order/Work Authorization are genuine (i.e., not counterfeit) and match the quality, test reports, markings and/or fitness for use required by the Purchase Order/Work Authorization".

The statement shall be on supplier letterhead and signed by an authorized agent of the supplier.

T. Certificate of Conformance

The requirements for certificate of conformance will be in the applicable procurement specifications and construction guidelines. For example: The Supplier/Manufacturer shall provide a legible/reproducible Certification of Conformance. Supplier's/Manufacturer's authorized representative responsible for quality shall sign the Certification of Conformance.

This Certification of Conformance shall, as a minimum:

1. Identify the appropriate Purchase Order/Work Authorization number under which the material, equipment, item or service is being supplied.

2. Supplier/Manufacturer shall warrant that all items furnished meet the requirements of the Purchase Order/Work Authorization.

One copy of the documentation, unless otherwise specified, shall accompany the applicable item shipped. For subsequent shipments on this Purchase Order/Work Authorization, reference may be made to documentation provided with earlier shipments, instead of duplicating such documentation.

Recommended Spare Parts Listing

The Contractor will require that the vendors submit, with or prior to item shipment, a recommended spare parts list. The list shall provide the name and address of the original supplier of the replacement part, and the part's drawings, specification, or catalog identity including applicable change or revision information.

Software Products and/or Services Where Software is Used

A. Design/Development of Custom Software

The Contractor will provide monitoring and controls as identified in this document. If new software is developed by the Contractor the following requirements apply:

1. Based on requirements provided to the Contractor, the Contractor shall submit the following information for Owner review for software development:
   - Description of the major components of the software design as they relate to the software requirements.
   - Technical description of the software with respect to the theoretical basis, mathematical model, control flow, data flow, control logic, and data structure.
   - Description of allowable or prescribed ranges for inputs and outputs
   - List of integration points (interfaces)
   - Data model
   - Hardware/Software configuration
   - Design described in a manner that can be translated into code
   - Computer program listing(s)
2. The Contractor shall develop and submit to Owner a Software Management Plan and procedures that describe their computer software development, test, and configuration management process. The plan shall, as a minimum, contain the following:
   - Identify the software products covered by the Software Management Plan.
   - Describe Contractor organizations responsible for performing the work and achieving software quality and their tasks and responsibilities. Clearly identify any Owner interfaces, and requirements.
   - Describe the configuration management methodology.
   - Describe the types of documentation to be prepared, reviewed, and maintained during software design, development, implementation, test and use.
   - Describe the process for reporting and documenting software problems/errors, evaluating the impacts of problems on previous measurements and uses, and determining the appropriate corrective action(s).
   - Identify standards, conventions, techniques, or methodologies that guide the software development, as well as the methods used to ensure implementation of requirements.
   - Provide procedure(s) for establishing and maintaining the integrity of data, embodied mathematical models, and output files.
   - Specify methods to verify and validate developed, acquired, or modified software.
3. A copy of the original program code shall be maintained and submitted to Owner as a Submittal.
4. Configuration management during the development and/or modification of computer software shall be identified and documented.

- Uniquely identify each configuration item (e.g., screens, reports, tables, documents, etc.)
- Configuration status accounting information shall be documented and identify the approved configuration, status of proposed changes to the configuration, status of approved changes, and information to support the functions of the configuration identification, and configuration control.
- Identify changes to configuration items by revisions. Change control processes shall provide objective evidence of evaluation, coordination, and approval of changes prior to implementation of the change.
- Provide the ability to uniquely identify each configuration of the revised software available for use.

5. Verification and Validation activities shall be performed to ensure software requirements are correctly specified and implemented in the design criteria, test documentation, and completed code. Such verification shall ensure traceability of test results to specified functional requirement.
   - Software testing shall include development testing, validation reviews, verification testing when appropriate.
   - Software shall be acceptance tested when installed, after changes, and periodically during use, as appropriate during the contract.
   - Design verification shall be completed and design outputs released for use, before relying on structures, systems, components, or computer programs to perform their function and before installation become irreversible.
   - The monitoring and control functions will be tested without impacting equipment operation as part of the verification process and prior to equipment operation.
6. The Contractor will supply standard support documents for software products. Standard product deliverables for custom software include: Requirements Document, System Design Description, Test Documents (plan, test cases, and test results), Installation/Operations manual, Installation Plan/Checkout, Acceptance Test Report, and User Documentation.
7. The Contractor will provide for installation assistance, checkout, and training of operators and users.
8. Acceptance of the computer software and hardware is based on the Contractor providing a functioning monitoring and control system that is integrated into the existing Owner system.

B. Design of Hardware with Software Instrumentation and Controls (e.g., PLCs)

1. Based on requirements provided to the Contractor, the Contractor shall submit the following information for Owner review for system development:
   - Description of the major components of the software design as they relate to the system requirements.

- Technical description of the hardware/software with respect to the theoretical basis, mathematical model, control flow, data flow, control logic, and data structure.
- Description of allowable or prescribed ranges for inputs and outputs
- List of integration points (interfaces)
- Data model, associated drawings, diagrams, equipments lists, etc.
- Hardware/Software configuration
- Design described in a manner that can be translated into code
- Computer program listing(s)

2. The Contractor shall develop and submit to Owner a System Management Plan and procedures that describe their computer software development, test, and configuration management process. The plan shall, as a minimum, contain the following:
    - Identify the software products covered by the System Management Plan.
    - Describe Contractor organizations responsible for performing the work and achieving software quality and their tasks and responsibilities. Clearly identify any Owner interfaces, and requirements.
    - Describe the configuration management methodology.
    - Describe the types of documentation to be prepared, reviewed, and maintained during system design, development, implementation, test and use.
    - Describe the process for reporting and documenting software problems/errors, evaluating the impacts of problems on previous measurements and uses, and determining the appropriate corrective action(s).
    - Identify standards, conventions, techniques, or methodologies that guide the software development, as well as the methods used to ensure implementation of requirements.
    - Provide procedure(s) for establishing and maintaining the integrity of data, embodied mathematical models, and output files.
    - Specify methods to verify and validate developed, acquired or modified software.
3. A copy of the original program code shall be maintained and submitted to Owner as a Submittal.
4. Configuration management during the development and/or modification of computer software shall be identified and documented.
    - Uniquely identify each configuration item (e.g., screens, reports, tables, documents, etc.)

- Configuration status accounting information shall be documented and identify the approved configuration, status of proposed changes to the configuration, status of approved changes, and information to support the functions of the configuration identification, and configuration control.
- Identify changes to configuration items by revisions. Change control processes shall provide objective evidence of evaluation, coordination, and approval of changes prior to implementation of the change.
- Provide the ability to uniquely identify each configuration of the revised software available for use.

5. Verification and Validation activities shall be performed to ensure software requirements are correctly specified and implemented in the design criteria, test documentation, and completed code. Such verification shall ensure traceability of test results to specified functional requirement.
    - Software testing shall include development testing, validation reviews, verification testing when appropriate.
    - Software shall be acceptance tested when installed, after changes, and periodically during use, as appropriate during the contract.
    - Design verification shall be completed and design outputs released for use, before relying on structures, systems, components, or computer programs to perform their function and before installation become irreversible.
    - List expected validation tests, hardware integration tests, and in-use tests to be conducted and the controls to be applied. A validation and verification report shall be submitted to Owner for approval. It will be used in conjunction with Owner acceptance testing/criteria to document successful completion of the Work Authorization.
6. Standard support documents are required for hardware/software products. It must be determined as to which Owner or the Contractor will provide. Standard product deliverables for hardware/software systems include: Requirements Document, System Design Description, Test Documents (plan, test cases, and test results), Installation/Operations manual, Installation Plan/Checkout, Acceptance Test Report, and User Documentation.
7. Contractor must provide installation assistance, checkout, and training of operators and users.
8. Acceptance of the computer software and hardware is based on the Contractor providing a functioning monitoring and control system that is integrated into the existing Owner system.

MEETINGS, SUBMITTALS, WORK & PROJECT CONTROL REQUIREMENTS

Meetings

A. After Work Authorization award, the contractor shall participate in a Project Kickoff Meeting to be held at CREC. The time, date, and agenda for the meeting will be provided to the Contractor upon Work Authorization award. The kick-off meeting will be within 10 days of Work Authorization award.

B. The person or persons designated by the Contractor to attend all meetings shall have all required authority to make decisions and commit Contractor to technical decisions made during meetings.

C. Weekly Progress Meetings

1. At the weekly progress meeting, Contractor shall submit a written report showing actual man-hours expended versus planned and scheduled progress versus actual progress giving details of Work completed in relation to the approved schedule, together with a two (2) week "look ahead" which provides details of how the Work will be completed.

2. Contractor shall attend a weekly coordination meeting together with various contractors at the jobsite. Attendance can be by telecommunication if approved by PEF Designated Representative.

H. Pre-job / Weekly Safety Meeting

1. All Contractor employees shall attend indoctrination and orientation prior to commencing work at the jobsite. This pre-job meeting will be held at CREC as set up by the Contractor.

2. Additional weekly safety meetings for all craft employees shall be held during active work.

I. Other Meetings

1. Contractor participation in certain additional activities shall also be required. These activities shall include, but are not limited to:

   a. Indoctrination and orientation of all Contractor's employees prior to commencing work at the jobsite (This includes the entire labor force and all new hires). The meeting will last approximately 3 hours.

2. Weekly gang box safety meetings organized and conducted by Contractor and attended by all of Contractor's employees involved in the field work. Contractor shall be responsible for arranging and conducting these meetings with its craft employees. The meetings should last approximately 1 hour.

Additional Detail

1. The Contractor is responsible to coordinate and conduct all the Project interface meetings discussed in this section. The Contractor will:

   - Consult with the Project's Designated Representative in developing the meeting agendas. The Contractor will provide an agenda to the meeting attendees for each meeting a minimum of 24 hours in advance to the meeting.
   - Start each meeting with a safety topic discussion. This discussion is not meant to last more than 5-10 minutes.

- The Contractor will take meeting minutes and distribute the meeting minutes for review within 2 days of the meeting. After allowing 1 day for comments the meeting minutes will be issued as final within 1 week of the meeting.
- The Contractor will maintain a list of Owner and associated Project personnel for meeting minute distribution. The list is to be approved by the Project's Designated Representative.

a. The Contractor will participate in a Kick off meeting within 10 days of the Notice to Proceed is issued by Owner's Contract Administrator.

b. The Kick-off Meeting will be at CREC and include:

- Safety & human performance topics
- Introductions
- Owner presentation – ~2 hour
    - o Project & CREC Site Safety Expectations
    - o Work Authorization overview and deliverables
    - o Contractor communications and progress reporting
    - o Site access and training
- Contractor's overview of the Project organization including a discussion of how the Contractor will interface with Owner Personnel.
- Contractor's safety culture
- Contractor's Project Organization & Key personnel
- Contractor's on site work
- Contractor's approach to contracted work, including engineering & procurement specifications,
- Contractor's use of design criteria manual
- Contracted deliverables and milestones
- Project schedule – Level III
- Contractor's cost control & earned value system

2. Weekly Status Meetings will be approx. 1 hour, set up and conducted by the Contractor. The meeting will be setup at the same time and location every week. The meeting will consist of:

- Safety & human performance topics
- Earned value status (cost vs. schedule)
- Projected estimate at completion cost (EAC)

- Accomplishments/Milestones
- Issues/Request for Information forms and status of open requests
- Scheduled accomplishments for next week
- Number of personnel working on the project (last week and next week)
- 4-week look ahead activities and support requirements
- General discussion – Q&A

3. Monthly cost accounting status meetings will consist of weekly meeting content plus end of month accruals.
4. The Contractor will conduct daily pre-job safety briefings. The briefing will at a minimum include:
    - Review of yesterday's activities
    - Overview of planned activities for the day and required PPE
    - Required materials
    - Potential safety issues & concerns
    - Activities being completed by others in nearby areas
    - Support requirements
    - Expected work site conditions
    - Q&A
5. Periodically during management oversight observations.
    - The Contractor will have periodic reviews and audits. These reviews will require the Contractor's support.

Request for Information

The Request for Information Form (RFI) will be used to document all formal requests for information or direction. The form is structured to ensure that if the required direction or the request is acted on in a timely manner. In addition, the RFI will ensure that potential impact on the project's cost, schedule, or scope is properly identified and managed.

The Contractor will set up and maintain the RFI log. The Contractor is responsible for the distribution of the RFIs.

Submittals

A. The Contractor's submittals shall be submitted to Owner in accordance with the instructions contained in the Attachment A, Submittal Register.

B. The Contractor submittals identified in this Work Authorization and summarized on the Submittal Register shall be submitted by the Contractor using the supplied document submittal form.

Work Control Requirements

A. Contractor Work Control Processes

The Contractor shall submit its proposed Work Control Processes for approval within 30 days of contract notice to proceed (NTP). The work control process must cover all field activities including engineering walkdowns. The work process should identify:

- The organization that will be established to control the work,
- State the organizational responsibilities,
- Identify the measures that will be implemented to maintain a safe work environment,
- Housekeeping,
- Traffic control,
- Establishing and removing work boundaries,
- Interface with Owner support and coordination of work (Owner notification of work activities),
- Personal Protection Equipment identification and enforcement,
- Work document development, control, and approval,
- Conduct of pre-job and safety meetings,
- Control of chemicals,
- Work coordination,
- And, incorporation of environmental permit information into the work process.

DELIVERABLES, MILESTONES AND PERFORMANCE SCHEDULE

Deliverables

The Contractor deliverables are as follows:

- o Project Quality Assurance/Control Plan
- o Project Safety and Health Plan
- o Environmental Compliance Plan
- o Engineering 30% design package
- o Engineering 70% design package
- o Final design package (Design Criteria Manual), including:
- o Completed Procurement Specifications
    - Engineering calculations
    - Engineered drawings
    - Construction instructions

- Testing requirements and test procedures
- Work control process plan
- Construction Estimate
- Final design Criteria Manual, (ready for construction).

Milestones

[redacted]

Performance Schedule

[redacted]

ATTACHMENT A

SUBMITTAL REGISTER

Submittal Register Definitions

1. Numerical submittal sequence number: Example: 1, 2, 3, 4, ... (or organized by topics and project assigned coding structure)

2. Number and Type of Copies (No / Type Copies): Example: E (Electronic only), 6 (Six Hard Copies), 1, E (One Hard Copy, and Electronic)

3. Submittal Type:

APP =	For Approval (the submittal is provided with the intent that Owner will review and approve the submittal prior to the contractor proceeding with work).
ACC =	For Acceptance (the submittal is provided for information with the intent that Owner will accept the submittal)
AFW =	Approval for Work (the submittal is provided with the intent that Owner authorizes work to be performed to the submittal)

4. Format: this describes the type of submittal required:

DWG	An AutoCAD drawing using the CREC standard formatting
MFC	Microsoft Format Compatible application (Word, Excel, Access, PowerPoint)
P3	A Primavera Project Planner schedule
GEN	General or Open Format/Media
PDF	Adobe Acrobat (Portable Document Format)

5. Document Family:

CON	Construction
ENG	Engineering
FAB	Fabrication
H&S	Health and Safety
PRO	Procurement
QAC	Quality
PROJ	Project
VI	Vendor Information
OTHER	Other

6. Description / Document Title: Title or general description of the document.

7. Submittal Date: Actual date or number of Calendar Days before or after a milestone that a submittal is due from the Contractor: Example: June 1, 2005 or CD + 60 [60 days after Conceptual Design Complete]

CD	Conceptual Design Complete
PD	Preliminary Design Complete
FD	Final Design Complete
M	Mobilization
SC	Start of Construction
EC	End of Construction
A	Date of Award

8. Buyer Review Time (Work Days): Example: 3 Days

9. Contract Reference: Cross reference to the Contract requirement that defines this submittal: Example: SOW 3.1.2.

Submittal Register:

The Contractor shall meet the required schedule and provide the documents specified in accordance with the following submittals.

Contract Number and Name:						Revision:		
1. Submittal No.	2. No. of Copies*	3. Submittal Type	4. Format	5. Document Family(ies)	6. Description / Document Title	7. Submittal Date (Calendar Days)	8. Buyer Review Time (Work Days)	9. Contract Reference
1	1	APP	PDF	OTHER	Site Access Forms	Prior to access	48 hrs.	2.4
2	1	ACC	GEN	PRO	Earned Value Information	Weekly	2	4.6 4
3	1	ACC	PDF	H&S	Corporate Health & Safety Plan	With Bid	7	4.7
4	1	APP	MFC	H&S	Project specific HASP	After Award	7	4.7, 6.2
5	1	APP	MFC	QAC	Quality Assurance Inspection (Control) Plan	30 days after award	7	6.3 G
6	1	ACC	PDF	QAC	Quality Assurance Program Manual	With Bid	7	6.4 A
7	1	APP	MFC	QAC	Software Management Plan		7	6.4 E
8	1	ACC	MFC	ENG	Work Control Process	30 after NTP	7	6.4 O
9	1	ACC	P3	ENG	Draft Performance Schedule	With Bid	7	6.5 A
10	1	APP	P3	ENG	Detailed Performance Schedule	15 days after Contract Award	7	7.1 C

PEF-POD4-00059

090007 Hearing Exhibit - 00002633

Exhibit 1 – Work Authorization No. 221186-24

Contract Number and Name:						Revision:		
1. Submittal No.	2. No. of Copies*	3. Submittal Type	4. Format	5. Document Family(ies)	6. Description / Document Title	7. Submittal Date (Calendar Days)	8. Buyer Review Time (Work Days)	9. Contract Reference
11	1	APP	GEN	OTHER	Proposed temporary Facilities	Prior to Mob.	5	A 3.0 C
12	5	APP	MFC	ENG	30% Design Review	CD	7	8.1
13	5	APP	MFC	ENG	70% Design Review	CD	7	8.1
14	10	APP	MFC	ENG	Completed Design	FD	7	8.1
	5	APP	MFC	ENG	Environmental Compliance Plan	FD	7	8.1
16	5	APP	GEN	ENG	Estimate for Construction	FD	3	8.1

ATTACHMENT B

SITE COORDINATION REQUIREMENTS, FACILITIES AND UTILITIES

General

A. CREC Survey bench marks are available for setting out the Work. The Contractor is responsible to complete the necessary surveys from the CREC benchmarks to support the Work. The Project drawings will use the CREC site coordinates and elevation.

B. The Contractor must establish location and extent of service lines in area of Work and notify Owner of findings. The Contractor will identify the utilities and service lines (including abandoned lines) in the design package. The Contractor will take all precautions to ensure that there are no unknown services in the work area.

C. Where unknown services are encountered, immediately advise Owner and confirm findings in writing. Identify the lines in the construction guidelines.

D. Record locations, including elevations, of maintained, rerouted and abandoned service(s). Provide these locations to Owner. Owner will provide direction on relocating the service line. Several lines have been identified to be relocated by the Contractor with this Work Authorization. This section is referring to newly identified utility or service lines.

E. Limited medical services on a "Good Samaritan" basis: Initial first aid shall be provided by the Contractor. Additional support can be obtained by calling the emergency phone number and identifying the emergency, (on site number 311, the off-site call in number is (352) 563-2943 x2120 for CR 1&2 Main Control Room).

Site Coordination Requirements

A. Another Owner Contractor, PMI Ash, has ongoing operations near the work location. The Contractor must continue to provide access and egress from the PMI work location. The Contractor must provide a design to allow for continued operation by PMI.

B. Prior to bringing any chemical or hazardous material onto CREC property the Contractor must obtain Owner approval.

C. Owner will obtain all environmental permits in support of this work. The Contractor is responsible to comply with the environmental permits.

D. The Construction Contractor will work with Owner personnel and shall obtain local construction permits.

E. Parking facilities. Owner is not financially responsible for any damage or unlawful acts to any Contractor equipment or private vehicles parked in designated parking areas.

Temporary Facilities and Utilities

A. Contractor shall provide, operate, maintain and dispose of all temporary buildings, including change rooms, port-a-potty, & office trailers.

B. Construction water and hydrostatic test water will be identified at points on the job site as designated by Owner's Designated Representative (DR). Connections to and disconnections from water supply shall be by Contractor and coordinated through Owner personnel.

C. The Contractor will be given access, without charge, to limited electrical, and water services in the vicinity of their work site. The quantities and characteristics of these utilities will be limited to that which is available from existing outlets near the work location. The following services will be discussed at the Pre-bid meeting.

1. No electrical power will be provided until the modifications at the CREC substation are complete and the Contractor has brought electrical power to the work location.
2. Non-Potable Water is available within ~¼ mile of the work location.
3. Owner will provide 2 telephone lines and a facsimile line to the Contractors office trailer. This service includes two telephones and local telephone service.
4. The Contractor shall be required to furnish all drinking water.
5. The Contractor may bring limited temporary field offices, tool trailers, etc., on-site for use during performance of the Work Authorization, although there is very limited space. Owner will be provided Office area in a nearby location if desired at no cost to the Contractor. The Owner proposed office location will be identified during the pre-bid conference. The Contractor shall submit the number, type, size, and a sketch of the proposed location of each facility for approval by Owner prior to mobilization.

Job Site Perimeter Security Fencing and Access Gates

The Contractor shall provide temporary fencing to secure work areas, temporary facilities areas materials and equipment storage areas as agreed with and approved by Owner.

Telephone Lines

Telephone line(s) will be provided at the Owner identified office location. Contractor shall be responsible for any use charges or periodic charges associated with the lines assigned to Contractor.

Break and Smoking Areas.

Smoking is not allowed within any buildings at CREC. Break areas will be approved by Owner.

Fire Protection.

The Contractor is responsible to identify the need for and provide fire protection of any temporary facilities.

Waste Management.

The Contractor is responsible to remove any construction generated debris. Office waste will be collected and transported to existing dumpsters west of CR2. No hazardous waste is allowed to be removed by the Contractor.

Emergency Eyewash and Showers.

The Contractor must provide eyewash and emergency showers at the required locations.

Trash Disposal.

The Contractor will accumulate and stage trash with and in the Owner trash containers.

Temporary Facilities

A. Except as otherwise identified, the supply, installation, provision, maintenance, repair, and final removal of all temporary facilities and utilities, necessary for full and complete performance of the Work, is the sole responsibility of the Contractor.

B. Such items shall include, but not necessarily be limited to, those listed below. The type of facilities, move-in and move-out dates, and locations on the job site shall be subject to and in accordance with the review and approval of Owner.

C. Asset management program of Contractor's workers, tools, materials, and equipment shall be provided by the Contractor.

D. Construction Contractor is responsible for landscaping, erosion, dust control; mud, and sand removal are the responsibility of the Contractor. The Contractor shall perform fugitive dust control and submit a Fugitive Dust Control Plan to Owner for review and concurrence.

Temporary Facility and Lay-down Area

A. Limited roughly graded space near the metrology tower will be provided for Construction material & equipment lay-down.

B. Upon demobilization, the land previously occupied by Contractor's Temporary Facilities and Lay-down area shall be returned to its pre-construction condition or better. This requirement shall also apply to all Temporary Roads, and Parking, Lay-down areas and Temporary Utilities.

C. The provision, operation and maintenance of sanitary systems, industrial systems, storm drainage and utility sewage systems for Contractor's Temporary Facilities is the responsibility of the Contractor including collection, holding, processing and disposal.

Storage Compounds

A. Adequate weather tight storage, for storage of materials, tools and equipment which are subject to damage by weather. The location of storage compounds must be agreed with Owner before materials are brought on site. Such compounds shall be maintained for the storage of the approved materials and for no other purpose.

Construction Power Guidelines

A. Includes connections to and disconnections from Owner or Owner provided construction power supply, transforming to lower voltage and distribution.

B. Construction power is for the joint use of all contractors engaged at the job site.

C. Onsite generation of power is allowed providing that such power is obtained through the use of properly installed, acoustically insulated diesel electric generating units.

D. Contractor's distribution system, lighting systems and wiring shall be installed in a proper manner and maintained in a satisfactory condition.

E. No weight shall be imposed upon any electric cable nor staging, ladder or similar equipment shall rest against or be attached to it. Temporary power cables in use by Contractor must be positioned so that they do not cause a tripping hazard (Run 8 ft/2.5 meters overhead or laid neatly out of walkways).

F. Electrical inspection and oversight will be provided by Contractor.

G. The Contractor must use of GFI at source for portable tools and equipment / extension cord use.

Temporary Facility Area Power, Lighting and Heating Supply

A. All electrical installations within temporary buildings shall be in accordance with the NFPA National Electric Code. Inspection and oversight will be provided by a Contractor.

B. For all equipment the power supply system(s) and components shall meet all National Electric Code (NEC) / National Electric Safety Code (NESC) requirements, and shall be listed by an independent testing laboratory such as Underwriter's Laboratory (UL) or Factory Mutual, suitable for outdoor use when to be used outdoors.

C. Includes connections to and disconnections from Owner or Owner provided construction power supply, transforming to lower voltage and distribution.

D. Before Contractor plugs in any electrical appliance to any plug socket belonging to Owner it shall ensure that the appliance is in good condition and is fitted with a suitable cable including fully rated and insulated neutral conductor and protective ground conductor.

E. Electrical inspection and oversight will be provided by a third party inspector.

F. Job site excavation rework, and weather repair is the responsibility of the Contractor. Dewatering activities require the prior approval of Owner and a Surface water discharge permit, unless waived by Owner.

Construction Water

A. Contractor shall provide all temporary water distribution supply lines and water storage facilities. Contractor shall distribute and convey water in an efficient and orderly way. Leaks and waste shall be minimized and care shall be exercised to eliminate the buildup and dispersal of mud resulting from leaks, spills and truck loading operations.

B. Contractor is also responsible for the safe and proper disposal of water into either local drainage systems or, where these are either not available or water has become contaminated, to off-job-site disposal locations approved by Owner.

Potable Water

The Contractor shall supply potable water, including ice. The Construction Contractor shall coordinate distribution to points of consumption in appropriate receptacles accompanied by suitable drinking vessels.

Testing Water

A. Construction Contractor shall provide all distribution, supply lines and water storage facilities. Contractor shall distribute and convey water in an efficient and orderly way. Leaks and waste shall be minimized and care shall be exercised to eliminate the buildup and dispersal of mud resulting from leaks, spills and truck loading operations. Contractor shall provide all requisite corrosion inhibitors, antifreeze and other additives required to perform testing in accordance with specification.

B. Construction Contractor is also responsible for the safe and proper disposal of water into either local drainage systems or, where these are either not available or water has become contaminated, to off construction-site disposal locations approved by Owner.

Water Disposal and De-watering

Construction Contractor shall perform all necessary de-watering and permitted disposal of ground water. Storm drainage, surface drainage and discharge of construction wastes shall be managed to prevent pooling of water on the job site and to prevent interference with the operations of other Contractors and organizations on or adjacent to the discharge areas.

Sanitary Facilities

A. Contractor shall provide and operate his sewage facilities in a manner that eliminates health risks, and obnoxious odors.

B. Contractor shall be responsible for all temporary sanitary facilities, including janitorial services, storage and removal of sewage. All temporary toilets shall be kept in a constant sanitary condition and shall be in compliance with all applicable health or other regulations. Portable enclosed toilets may be used in construction and fabrication areas provided they are regularly attended and maintained. Before completion all toilet facilities shall be removed and their areas disinfected and filled.

Fuels and Lubricants

A. Oils, greases and similar materials must be stored in fire proof bins or buildings or in a fenced compound remote from other combustible materials as approved by Owner.

B. "No smoking" signs shall be provided by Contractor and prominently displayed in areas where flammable materials are stored. Additionally, Contractor shall provide and maintain suitable fire extinguisher in such areas.

C. Contractor shall provide all fuel for heating, ventilation and air conditioning of Temporary Facilities (unless these are run using free issue power).

D. The Contractor must use appropriate fire control containments for vessels storing fuels and lubricants.

Communication Facilities

A. Contractor shall provide and operate all means of communication, including but not limited to telephones, facsimiles, and radios which shall be approved by Owner. Owner shall provide telephone lines in accordance with the provisions of 9.3.

B. Compressed Air, Steam, and Gases

These services will be provided by the Contractor's design and approved by Owner.

Temporary Roads, Parking, and Traffic Control

A. The Design Contractor shall design for temporary roads and traffic control.

a. The Construction Contractor shall be responsible for providing and maintaining all roads and parking areas deemed necessary by Contractor for access, and parking in Temporary Facilities areas, construction areas, and between areas. Contractor provided roads and parking areas shall be constructed so as to provide for adequate safe movement of light and heavy vehicles, and equipment. Contractor's temporary roads shall be constructed in a manner ensuring the avoidance of damage to all permanent roads, facilities, and underground structures.

b. Contractor shall maintain his temporary roads and parking areas regularly, and shall water all his roads as a dust abatement measure.

c. Contractor shall remove and restore areas occupied by Temporary roads and parking areas upon completion of the Work.

d. Temporary construction steel, decommissioning and miscellaneous equipment supports, platforms, and ladders around equipment are the responsibility of the Contractor.

e. Project signs for traffic control, and direction, and for identifying project areas. Signage shall be based where possible on International signage standards and conventions

f. Transportation facilities on and off job site. Only Contractor vehicles, as approved by Owner, will be allowed on the job site. Limited personal vehicles will be allowed on site. The Contractor's personnel may be required to use Owner provided shuttle transportation, during specific periods of high activity (i.e. 2009 outage – September through December).

g. Equipment delivery slippages in schedule are the responsibility of the Contractor.

Material Handling, Rigging, and Scaffolding

A. The design Contractor will provide for the following in their design documents:

1. Contractor shall provide and operate all cranes and other necessary equipment for handling; hauling, unloading and receiving Contractor supplied materials, tools and equipment.
2. Containers and services for hauling, removal and disposal of construction waste and debris. Contractor shall advise Owner in writing of any need for disposal of hazardous waste prior to generation of the waste. The Contractor is responsible to properly package, label, and turn the waste over to Owner. Owner will dispose of all hazardous waste generated at CREC.
3. Supply, erection, maintenance and dismantling of scaffolding and other means of access to the Work

Weather Protection

Weather Protection of the Work and any methods required to allow continuation of the Work during periods of inclement weather.

The Contractor is responsible for the proper storage of all equipment and material. There is no protected storage currently available for use by the Contractor.

Equipment

A. Small tools

The Contractor will provide all small tools.

B. All standard expendable or consumable construction items and supplies.

The Contractor is responsible for expendable or consumable construction items and supplies.

C. Temporary lighting. Provision and operation to allow the Work to be performed in a safe manner regardless of ambient lighting conditions.

The Contractor is responsible for temporary lighting.

Personnel Protective Equipment

The Contractor is responsible for identifying and providing all personnel protective clothing.

Permits

Owner is responsible for obtaining environmental permits, licenses and government approvals for the Contractor. The Contractor will obtain all local construction permits, (coordinated through Owner). It is the Contractor's sole responsibility to ensure compliance with permits in accordance with all laws and regulations.

First Aid Facilities

CREC has first aid responders and there is a hospital near the site. The Contractor is responsible to provide immediate medical attention and CREC notifications if an emergency condition is identified.

Calibration

The Contractor will identify the instruments to be calibrated. Construction guidelines should contain the requirement that equipment provided and installed by the Contractor shall be calibrated, and maintained by the Contractor until Work Authorization completion or system turn-over.

Spare Parts

A. Spare parts lists will be proved by the Contractor. The Contractor shall:

1. Provide a list of recommended spare parts to Owner for approval. Include pricing, delivery time, description, etc.
2. Coordinate delivery of spare parts to the Owner approved location.
3. Label spare parts, as directed by Owner.

Documentation and Turn-over

A. The design Contractor will provide for the following in their design documents:

1. The contractor will be required to participate in the project turnover process by assisting Owner in developing and completing the project punch list. The contractor shall notify Owner no later than one (1) day after completing the punch list item(s).
2. The following construction documentation will be maintained through the construction and turned over during the testing and acceptance period prior to declaring facilities as mechanically or substantially complete:
   a. Operating manuals,
   b. Maintenance manuals,
   c. Spare parts lists,
   d. Equipment specifications and manufacturers information,
   e. MSDS library,
   f. As-built/as-installed verified construction/assembly drawings, and
   g. Supporting shop-drawings, isometric drawings, weld maps, and inspection and testing records.
   h. The Contractor must provide input for and assist in development of post construction operating procedures with Owner personnel.

   Note: On site construction and start-up support will be included under separate release. No time was estimated for this support outside of Mesa's office. Contractor is required to develop the testing procedures for the equipment and systems in the design phase under this contract.

Construction debris

The design Contractor will provide for the following in their design documents:

Construction debris shall be cleaned up by the Contractor and staged in approved waste containers. The Contractor is responsible to remove non-hazardous construction debris.

ATTACHMENT C

NOT USED

ATTACHMENT D

PHASE 2 CONCEPTUAL DESIGN REPORT

ATTACHMENT E

REQUEST FOR INFORMATION FORM

RFI Number:													
POINT OF DISCHARGE (POD) PROJECT REQUEST FOR INFORMATION (RFI) FORM													
Date:							Contractor's Project Manager Approval:						
Initiator:													
Suggested resolution:													
Date that response is needed by to prevent Project impact:													
Potential Impact													
Scope			Schedule			Cost				Safety			
Description of Impact:													
Progress Energy Direction, Resolution, Clarification													
Contract Change Required (Yes or No)													
Owner Project Manager Receipt Acknowledgement:													
										Date:			
Project Manager Disposition Approval:													
										Date:			
EPC Project Manager Disposition Approval:													
										Date:			
Contract Change Complete (Yes or No) If Required													
Owner Procurement Specialist Contract Change Complete Acknowledgement:													
										Date:			

Exhibit 2 – Project Milestone Schedule

[redacted]

PEF-POD4-00074

[redacted]

PEF-POD4-00075

2

[redacted]

PEF-POD4-00076

3

[redacted]

Exhibit 4 – Work Authorization No. 221186-24

Contract Employee
Code of Ethics Acknowledgment Form

Please go to the following website to review the Progress Energy Code of Ethics prior to signing this Acknowledgment Form. Hard copies are available upon request.

http://www.progress-energy.com/investors/corpgov/codeofethics.asp

I have read the Progress Energy Code of Ethics. I understand that the principles stated in the Code of Ethics represent those of Progress Energy as they relate to the work I perform as an independent contractor (or as an employee of an independent contractor of Progress Energy), and that violating those principles, or the legal and regulatory requirements applicable to my work may result in disciplinary action by my employer. I agree to abide by and support the legal and regulatory requirements applicable to my work. I understand that if I have questions concerning appropriate ethics or relevant legal and regulatory requirements, I should consult with my supervisor.

____
Signature of Contract Employee

____
Name of Contract Employee

____
Date

____
Contractor Organization

Contractor shall maintain completed forms. Do not return completed forms unless they are specifically requested by Owner.

Work Authorization 221186-24

Exhibit 5 – Specification S2a

Work Authorization 221186-24

Exhibit 6 – Design Criteria Manual

Progress Energy

Mesa Associates, Inc.
10604 Murdock Drive
Knoxville, TN 37932

Attention: Tim Cutshaw

CONTRACT NO. 221186
WORK AUTHORIZATION NO. 24
AMENDMENT NO. 1
EFFECTIVE February 1, 2009

This Amendment is governed by the terms and conditions of the above-referenced Contract. By this Amendment, Progress Energy Service Company, LLC, not in its individual capacity, but solely as agent for Progress Energy Florida, Inc., (hereinafter "Owner") offers to change the terms of the above-referenced Contract as follows:

<u>Changes</u>

Scope Changes will be documented via the RFI process explained in Attachment A of the Work Authorization. This process will document, for all changes to the Scope of Work, resources required, schedule impact, costs, and justification. An approved RFI shall be considered valid for authorizing a change. Once cumulative Scope changes, in aggregate or individually, exceed one hundred thousand dollars ($100,000) then the changes will be formally incorporated into an Amendment to the Work Authorization.

All other terms in the Contract or other Contract Amendments remain unchanged.

Please execute this Amendment, retain an original for your file, and return the other original within ten (10) calendar days to Sid Fowler, Progress Energy Service Company, LLC, P. O. Box 1551 (PEB-3C3), Raleigh, NC 27602 or via electronic transmittal to sidney.fowler@pgnmail.com

Sincerely,

Sid Fowler
Associate Sourcing Specialist
As Agent For
Progress Energy Florida, Inc.

<u>Accepted:</u>

MESA ASSOCIATES, INC.

By: ______________________

Name (printed): Timothy R. Cutshaw

Title: Vice President

Date: 3/27/09

Should the person's title who is executing this document not indicate that he/she is a corporate officer; an affidavit signed by a corporate officer shall be provided stating that the person whose name appears above is duly authorized to execute Contracts on behalf of the firm.

Progress Energy

Mesa Associates, Inc.
10604 Murdock Drive
Knoxville, TN 37932

Attention: Tim Cutshaw

CONTRACT NO. 221186
WORK AUTHORIZATION NO. 24
AMENDMENT NO. 02
EFFECTIVE August 6, 2009

This Amendment is governed by the terms and conditions of the above-referenced Contract. By this Amendment, Progress Energy Service Company, LLC, not in its individual capacity, but solely as agent for Progress Energy Florida, Inc., (hereinafter "Owner") offers to change the terms of the above-referenced Contract as follows:

<u>**Schedule**</u>

The schedule is Work is extended to October 1, 2009. As such, all Work shall be completed by Contractor and Accepted by Owner no later than October 1, 2009.

All other terms in the Contract or other Contract Amendments remain unchanged.

Please execute this Amendment, retain an original for your file, and return the other original within ten (10) calendar days to Sid Fowler, Progress Energy Service Company, LLC, P. O. Box 1551 (PEB-3C3), Raleigh, NC 27602 or via electronic transmittal to sidney.fowler@pgnmail.com.

Sincerely,

Sid Fowler
Associate Sourcing Specialist
As agent for
Progress Energy Florida, Inc.

<u>Accepted:</u>

MESA ASSOCIATES, LLC

By: ______________________

Name (printed): Timothy R. Cutshaw

Title: Vice President

Date: 8/7/09

Should the person's title who is executing this document not indicate that he/she is a corporate officer, an affidavit signed by a corporate officer shall be provided stating that the person whose name appears above is duly authorized to execute Contracts on behalf of the firm.

Progress Energy Service Company, LLC
[illegible]
[illegible]

PEF-POD4-00082

Progress Energy

Mesa Associates, Inc.
10604 Murdock Drive
Knoxville, TN 37932
Attention: Tim Cutshaw

CONTRACT NO. 221186
WORK AUTHORIZATION NO. 24
AMENDMENT NO. 03
EFFECTIVE August 31, 2009

This Amendment is governed by the terms and conditions of the above-referenced Contract. By this Amendment, Progress Energy Florida, Inc., (hereinafter "Owner") offers to change the terms of the above-referenced Contract as follows:

Contractor shall provide general engineering support to assist in developing the Cooling Tower construction Request for Proposal. Contractor shall assist in the review and selection of the construction contractor, provide general engineering support in review of contractor submittals during construction of the cooling tower, and provide other general support as requested by Owner's Designated Representative.

Services shall be provided in accordance with the current Time and Materials Rates outlined in the contract. Total expenditures under this Amendment shall not exceed Sixty Thousand Five Hundred Dollars ($60,500) without prior written approval of Owner's Designated Representative.

All other terms in the Contract and Amendments remain unchanged.

Please execute this Amendment, retain an original for your file, and return the other original within five (5) calendar days to jay.outcalt@pgnmail.com or Jay Outcalt, Progress Energy Florida, Inc., Crystal River 3 Nuclear Plant, 15760 West Powerline Street, Mail Code SA2C, Crystal River, FL 34428-6708.

Sincerely,

8/31/09

Jay Outcalt
Lead Contract Management Specialist

Accepted:

MESA ASSOCIATES, LLC

By: __________

Name (printed): Timothy B. Ramsey

Title: Associate Vice President

Date: 9/11/09

Should the person's title who is executing this document not indicate that he/she is a corporate officer, an affidavit signed by a corporate officer shall be provided stating that the person whose name appears above is duly authorized to execute Contracts on behalf of the firm.

CONTRACT NO. 433059

BETWEEN

PROGRESS ENERGY SERVICE COMPANY, LLC
Not in its individual capacity, but solely as agent for

PROGRESS ENERGY FLORIDA INC.

AND

EVAPTECH ME

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Contract No. 433059

This Contract (hereinafter "Contract"), effective January 26, 2009, by and between PROGRESS ENERGY SERVICE COMPANY, LLC, whose address is 410 South Wilmington Street, Raleigh, NC 27601, not in its individual capacity, but solely as agent for PROGRESS ENERGY FLORIDA, INC., (hereinafter referred to as "Owner"), and EvapTech ME a joint venture registered in the State of Florida, and whose office is located at 8331 Nieman Road, Lenexa, KS 66214 (hereinafter referred to as "Contractor").

In consideration of the mutual agreements herein contained, the parties hereto contract and agree as follows:

1.0 CONTRACT DOCUMENTS

This Contract and agreement shall consist of the following contract documents, and the attachments, exhibits, drawings, specifications and documents expressly referred to therein, all of which by this reference are incorporated herein and made a part of this Contract (hereinafter referred to as the "Contract").

The various parts of the Contract Documents are intended to supplement but not necessarily duplicate each other. Any Work exhibited in one part and not in another shall be executed as if it had been set forth in all parts, so that the Work will be constructed according to the complete design as determined by the Contract Documents taken as a whole.

Should anything necessary for a clear understanding of the Work be omitted from the Contract Documents, or should the requirements appear to be in conflict, the Contractor shall secure written instructions from Owner before proceeding with the Work affected thereby. It is understood and agreed that the Work shall be performed according to the true intent of the Contract Documents.

PART I – CONTRACT SUMMARY, TERMS & CONDITIONS AND EXECUTION
PART II – SCOPE OF WORK
PART III – CONTRACT PRICING
PART IV – SPECIFICATIONS

PRECEDENCE. In cases of express conflict between PARTS of the Contract, attachments, exhibits, drawings and specifications, the order of precedence shall be as follows:

- PART I
- PART II
- PART III
- PART IV
- Attachments
- Exhibits
- Drawings
-

This Contract sets forth the entire contract and agreement between the parties pertaining to said Work and supersedes all inquiries, proposals, agreements, negotiations and commitments, whether written or oral, prior to the date of execution of this Contract, pertaining to said Work or this Contract. The provisions of this Contract may be changed only by a writing executed by the parties to this Contract. Trade custom and trade usage are superseded by this Contract and shall not be applicable in the interpretation of performance of this Contract, except to the extent such trade custom or usage is expressly specified.

[redacted]

3.0 DEFINITIONS

"Change" means an addition, deletion or revision to the Scope of Work, Contract Schedule, or Contract Price.

"Change Order" – a request by either Owner or Contractor to add, delete or revise the Scope of Work, Contract Schedule or Contract Price when pricing for labor, subcontractors, material, etc have been documented on the RFI Form in Part II Attachment F.

"RFI Form " – form used when making request for Change to Scope of Work, Contract Schedule or Contract Price.

"Commissioning" is the process of commissioning the plant (e.g. beginning with individual component testing, progressing through sub-system and system testing, integrated system operation and performance testing, and ending with preparation for introduction of gas to the facility. These activities are generally Owner's responsibilities unless the contract scope specifically provides otherwise.

"Contract Schedule" The schedule provided by Contractor that has been integrated into the Master Project Schedule and accepted by Owner. This schedule shall meet the requirements set forth in Part I Section 13 and Part II – "Deliverables, Milestones, and Performance Schedules" and shall be the legally binding schedule for the performance of the Work.

"Constraints": Any factor (date, event or activity) which affects when an activity can be scheduled. Includes events being performed by others but affecting the Contractor Schedule.

"Contract Amendment" shall mean a written Change to the Contract Documents, signed by Owner and Contractor on or after the Effective Date of the Contract.

"Contract Documents" shall have the meaning set forth in Section 1, Contract Documents.

"Contract Price" shall be the firm fixed price set forth in Part III, Compensation, herein.

"CPM": Critical Path Method of planning, scheduling and controlling the Project events and activities. PRIMAVERA Project Management Software or SureTrack is the standard scheduling application for the Project. Contractor shall either use this software to develop all CPM schedules at all levels or shall provide all necessary information to Owner to allow Owner to develop such schedules.

"Day" shall mean calendar day.

"DFL: Direct Field Labor": All construction labor (general foreman and below) directly utilized in construction of permanent plant facilities (e.g. labor to install foundations, structural steel, erecting, welding and testing piping systems).

"Disclosing Party" is the Party disclosing Confidential and Proprietary Information.

"Drawings" shall mean all (a) drawings furnished by Owner as a basis for proposals, (b) supplementary drawings furnished by Owner to clarify and to define in greater detail the intent of the Contract Drawings and specifications, (c) drawings submitted by the successful bidder with its proposal provided such drawings are acceptable to Owner, and (d) engineering data and drawings submitted by Contractor during the progress of the Work, provided such drawings are acceptable to Owner.

"**Engineering**" shall mean all activities related to the engineering and design of the Work, such as calculations, specifications, drawings, and construction/installation details.

"**Engineering Contractor**" shall mean the Engineering firm hired by Owner and responsible for completion of Tasks 6a, 7a, 8a, and 10 and the portions of Tasks 1, 2, 3, and 4 relative to those tasks.

"**Exception-List**" is prepared by Contractor, after review with Owner at the time of turnover, when it is ready to issue the Final Notice of Completion. The list must be limited to the items that Owner agrees may be completed during the interim turnover period so as not to impact the project schedule. These will be items considered non-essential to a safe and orderly start-up.

"**Final Acceptance**" shall mean Owner's written acceptance of all Work performed under this Contract, based upon Owner's final inspection, the passing of 3rd party CTI performance testing, and Contractor's delivery to Owner of the final waiver and release of liens as set forth in Part I.

"**Final Notice of Completion**" is issued when all portions of the work covered by the Contract are mechanically complete. For the Key Contract Milestones set forth in Exhibit One, the associated Interim Turnover Notice shall constitute notification of Milestone Mechanical Completion.

"**Force Majeure**" shall have the meaning set forth in Section 15.0 of Part I.

"**Front End, Engineering, Procurement & Construction Schedule**" (Design, Supply and Erect Contracts only): An interim schedule, with the detailed tasks Contractor will perform over the first 90 calendar days following Notice to Proceed. This schedule will be used to monitor progress of the work until the Owner and Contractor mutually agree on the Contract Schedule. This schedule shall be submitted within fourteen (14) calendar days of award of Contract.

"**IFL: Indirect Field Labor**". All construction labor utilized in support of the construction of permanent plant facilities.

"**Indemnify**", with respect to any Claim or cost, means (1) to indemnify, save and hold harmless, reimburse and make whole on an after-tax basis, the designated indemnitee and its affiliates and their respective officers, directors, employees, partners and agents from any Claim or cost imposed on or incurred by the indemnitee, or asserted by any third party against the indemnitee; (2) to defend any suit or other action brought against the indemnitee on account of any Claim and (3) to pay any judgment against, and satisfy any equitable or other requirement imposed on, the indemnitee resulting from any such suit or action, along with all costs and expenses relative to any such Claim, including, without limitation, attorney's, consultant's and expert witness fees and public relations costs.

"**Jobsite**" shall mean Owner's Crystal River Energy Complex in its entirety but specifically the Clarifier Pond Location which has been chosen for the location of the Tower, the laydown area for the Work, and any other areas where Contractor is performing Work on Owner's property.

"Legal Requirements" means, to the extent applicable to the performance of the Contract, the Work, or the Plant, any federal, state, county or municipal statute or ordinance in effect on the Effective Date of this Contract, including federal, state or local taxation authorities or other fiscal law, or other law, regulation, statute, rule, code, direction, license, consent, permit or authorization, including any conditions attached thereto (whether relating to the Environment or otherwise) of the United States, the State of North Carolina, the County of Citrus or any subdivision thereof, or any other public body or authority or federal, state or local agency, department, inspector, official or public or statutory Person (whether autonomous or not) that has appropriate jurisdiction (in the case of ordinances, statutes or codes, the most recent edition or revision thereof in effect on the Effective Date of this Contract shall be included in the Legal Requirements), and Legal Requirements also include the Americans with Disabilities Act of 1990, 42 U.S.C. §12101 et seq. and the Foreign Corrupt Practices Act, 15 U.S.C. § 78dd-1 et seq. and the export laws, rules and regulations of the United States;

"Look Ahead Work Plan" (Level IV): A plan provided by Contractor showing, in chronological format: 1) status showing planned work and actual accomplishments for the previous period, 2) work planned for the current and the upcoming period and 3) second shift work for construction. This plan is updated and issued weekly.

"Master Project Schedule" shall mean the schedule maintained by Owner's Designated Representative to govern the implementation and completion of all areas of work related to the overall Crystal River Energy Complex Canal Cooling Project, as defined in Part II, including the portions of the work described in Part II to be performed by other contractors.

"Mechanical Completion" shall be defined as the schedule event when the tower has successfully completed all commissioning protocols, all punch-list items are complete and is ready to be put into service by Owner.

"Milestone" shall mean the principal events specified in the Contract Documents relating to an intermediate completion date or time prior to Final Acceptance of the Work.

"Notice" shall mean written notice in strict compliance with the terms hereof and in no event shall it be oral or constructive notice.

"Objectives vs. Accomplishments Listings": A management level chart prepared once a week that compares actual accomplishments to those planned for that reporting period.

"Owner" shall mean Progress Energy Florida, Inc.

"Owner Property" means any property, facility or equipment owned, leased or under the control of Owner wherever located, including land, buildings, structures, installation, boats, planes, helicopters and other vehicles.

"Progress Calculations": Contractor shall assign a weighted value to each component of the job, based upon milestone weightings provided by Owner (MileMarker). Actual physical progress will be statused for each component. Overall Project progress is based on the total earned value of the weighted percent progress for all components contained in the Contract. Contractor shall systematically update the progress calculations to accurately represent the project scope. Owner shall have right of approval of all weighting and statusing.

"Regulated Substance" means any chemical, material, substance or waste the exposure to, access to or Management of which is now or hereafter prohibited, limited or regulated by any law or governmental unit. Regulated Substances include without limitation ACM and Lead.

"Release(s)", with respect to any substance or material, means any spilling, leaking, pumping, emitting, emptying, discharging, injecting, escaping, leaching, dumping or disposing of such substance into the environment, or any other act or event the occurrence of which would require containment, remediation, notification or similar response under any law.

"Site Establishment" – Contractor's overhead costs and other general expenses to maintain the Contractor's presence on the work site for performance of the Work.

"Specification" means the documents in Part IV of this Contract, as amended by the technical exceptions and clarifications in the Proposal Document.

"Start-up" commences when steps are taken to bring the unit / plant to operation. It is complete when the unit / facility is operating at design capacity and producing to specifications as determined by performance testing. Start-up activities are Owner's responsibility.

"Substantial Completion" shall be defined as the schedule event when the construction on the Tower is completed, the punch list has been developed, and the Tower is ready for commissioning and testing.

"Subcontractor" shall mean and refer only to a corporation, partnership, or individual having a direct contract with Contractor for performing work covered by this Contract.

"Total Float Time": The amount of time between the early start date and the late start date or between the early finish date and the late finish date of activities of the schedule.

"Tower" means the once through, mechanical draft, counterflow cooling tower in its entirety, to be located on the Jobsite.

"Work" shall be defined per Part I Section 2.0 Scope of Work.

"Work Activity": An activity that requires time and resources (manpower, equipment, and/or material) to complete.

Whenever in these Contract Documents the words, **"as ordered," "as directed," "as required," "as permitted," "as allowed," or words or phrases of like import are used,** it shall be understood that the order, direction, requirement, permission, or allowance of Owner is intended only to the extent of judging compliance with the terms of the Contract; none of these terms shall imply that Owner has any authority or responsibility for supervision of the Contractor's forces or construction operations, such supervision and the sole responsibility therefore being strictly reserved for the Contractor.

Similarly the words **"approved," "reasonable," "suitable," "acceptable," "proper," "satisfactory," or words of like effect and import,** unless otherwise particularly specified herein, shall mean approved, reasonable, suitable, acceptable, proper, or satisfactory in the judgment of Owner or Contractor, as applicable, to the extent of judging compliance with the terms of the Contract; none of these terms shall imply that Owner has any authority or responsibility for supervision of the Contractor's forces or construction operations, such supervision and the sole responsibility therefore being strictly reserved for the Contractor.

4.0 WARRANTY

4.1 Contractor warrants that the Work shall comply strictly with the provisions of this Contract and all specifications, drawings and standards referred to in this Contract or thereafter furnished by Owner that the finished product shall be free from defects in design, materials and workmanship. Contractor further warrants that all materials, equipment and supplies furnished by Contractor for the Work shall be new. Any professional services supplied by Contractor as part of the Work will be performed in accordance with generally accepted standards and practices and free from error. Without limitation of any other rights or remedies of Owner, if any defect in the Work in violation of the foregoing warranties arises within the period set forth below, Contractor shall, upon receipt of written notice of such defect, promptly furnish, at no cost to Owner, design and engineering, labor, equipment and materials necessary to correct such defect and cause the Work to comply fully with the foregoing warranties as outlined herein and Contractor's special warranty, attached hereto, as Attachment M.

4.2 In the event Contractor shall have been notified of any defects in the Work in violation of Contractor's foregoing warranties and shall fail to promptly and adequately correct such defects, or in an emergency situation, where no such notice is required, Owner shall have the right to correct or to have such defects corrected for the account of Contractor, and Contractor shall promptly pay Owner the costs incurred in correcting such defects.

4.3 Contractor shall include, at a minimum, the foregoing warranty requirements in any subcontract that it places.

The warranties furnished by Contractor as expressly included herein constitute Contractor's sole warranty obligation hereunder and are in lieu of any other warranties or guarantees, express or implied, including warranties of merchantability or fitness for a particular purpose.

5. INSPECTION, TESTING AND QUALITY CONTROL

5.1 Contractor shall inspect all materials, supplies and equipment which are to be incorporated in the Work. In addition, Contractor shall conduct a continuous program of engineering, procurement and construction quality control for all Work. Contractor's quality control program and inspection procedures for the foregoing shall be submitted in writing to Owner for review and approval, in sufficient detail to delineate those items to be inspected and the manner in which they are to be inspected, and shall adequately describe all engineering, procurement and construction quality control activities contemplated, including provision for adequate documentation of Contractor's performance of such quality control and inspection.

5.2 Contractor shall, during the course of performance of the Work hereunder, without additional compensation, make or cause to be made all tests required by this Contract. Owner may require additional inspections and tests. Contractor shall furnish Owner with satisfactory documentation of the results of all inspections and tests. Owner shall be given not less than five (5) working days notice of any tests to be made by Contractor or Contractor's subcontractors in order that Owner may witness any such tests.

5.3 Owner and their representatives, and others as may be required by applicable laws, ordinances and regulations, shall have the right at all reasonable times to inspect the Work and all material, supplies and equipment for the Work at the jobsite and at Contractor's and its subcontractors' shops for conformance with the Contract. Contractor shall provide, or cause to be provided access and sufficient, safe and proper facilities for such inspections. Neither Owner's failure to make such inspection nor Owner's failure to discover defective workmanship, materials or equipment, nor Owner's approval of or payment to Contractor for such Work, materials or equipment shall prejudice the rights of Owner.

5.4 If Contractor covers any portion of the Work prior to any inspection or test provided for in the specifications, inspection schedule, or as previously requested by Owner, the cost of uncovering and covering the Work to allow for such inspection or test shall be borne by the Contractor. Reexamination of any Work may be ordered by Owner. In the event of such reexamination, if any material, equipment or any part of the Work is determined by Owner to be defective, Contractor shall not be reimbursed for uncovering, repair or corrective and restoration costs. If such Work is found to be in accordance with the Contract requirements upon such reexamination, Owner shall pay Contractor the cost of uncovering and restoration.

5.5 Rejection by Owner of any or all parts of defective Work for failure to conform with this Contract shall be final and binding. Such rejected Work shall be promptly corrected or replaced by Contractor at Contractor's expense. If Contractor fails to commence and diligently continue correction or replacement of such rejected Work immediately after receipt of written notice from Owner to correct or replace the rejected Work, Owner may at its option remove and replace the rejected Work, and Contractor shall promptly reimburse Owner for the costs of such removal and replacement of defective Work.

6. CONDITIONS AND RISKS OF WORK

Contractor represents that it has carefully examined the documentation, drawings and specifications for the Work and has fully acquainted itself with all other conditions relevant to the Work, and its surroundings, and Contractor assumes the risk of such conditions and will, regardless of such conditions (including the expense, difficulty of performing the Work, and/or negligence) fully complete the Work for the stated Contract Price without further recourse to Owner. Information on the site of the Work and local conditions at such site furnished by Owner in specifications, drawings or otherwise is not guaranteed by Owner and is furnished only for the convenience of Contractor.

7. ISSUED FOR CONSTRUCTION DRAWINGS AND SPECIFICATIONS

7.1 The Work shall be performed using only drawings and specifications marked "Issued for Construction" or equivalent by Owner. Such indication shall not relieve Contractor of any obligations under this Contract, nor constitute Owner assumption of responsibility for the accuracy or adequacy of any of Contractor's information or Work incorporated in such documents.

7.2 Contractor shall perform all Work outside of the areas marked "HOLD" on "Issued for Construction" specifications and drawings to maintain the schedule of Work, but shall not perform any Work in the areas or sections marked "HOLD" on "Issued for Construction" specifications and drawings until revised "Issued for Construction" specifications and drawings are received with the "HOLD" markings deleted.

7.3 If Contractor's schedule will be delayed by "HOLD" markings on specifications and drawings, Contractor shall report such delay to Owner in writing not less than five (5) working days prior to the start of the delay.

7.4 Contractor shall maintain at the work site a complete and current set of "Issued for Construction" drawings and specifications.

8. INTENT OF SPECIFICATIONS AND DRAWINGS

8.1 (For those drawings not supplied by Contractor) The specifications and drawings may not be complete in every detail. Contractor shall comply with their manifest intent and general purpose, taken as a whole, and shall not make use of any errors or omissions therein to the detriment of the Work. Should any conflict, error, omission or discrepancy appear in the drawings, specifications, instructions, in work done by others, or in site conditions Contractor shall notify Owner in writing at once and Owner will issue written instructions to be followed. If Contractor proceeds with any of the Work in question prior to receiving such instructions then required corrections shall be at Contractor's expense.

8.2 Contractor shall not deviate from the specifications and drawings without prior written approval from Owner.

8.3 Materials shall not be substituted for those specified, nor shall "or equal" items be furnished pursuant to the specifications without Owner prior written approval.

9. SAFETY

9.1 Contractor shall hold personnel safety at its highest priority and ensure that this is engrained in all personnel. Contractor shall be proactive in ensuring that safety is an integral part of all tasks. Contractor shall furnish all applicable personnel safety protection equipment and ensure that it is properly used at all times.

9.2 Contractor shall take necessary safety and other precautions to protect property and persons from damage, injury or illness arising out of the performance of the Work. Contractor shall comply strictly with plant safety procedures, local, municipal, provincial, state and national laws, orders, and regulations pertaining to health or safety which are applicable to Contractor or to the Work, including without limitation the Occupational Safety and Health Act of 1970 (84 U.S. Statutes 1590), as amended, and any state plans approved thereunder and regulations thereunder, to the extent applicable, and Contractor warrants the materials, equipment and facilities, whether temporary or permanent, furnished by Contractor in connection with the performance of the Work shall comply therewith. At all times while any of Contractor's employees, agents or subcontractors are on Owner's premises, Contractor shall be solely responsible for providing them with a safe place of employment, and Contractor shall inspect the places where its employees, agents or subcontractors are or may be present on Owner's premises and shall promptly take action to correct conditions which are or may become an unsafe place of employment for them.

9.3 Accidents, injuries and illnesses requiring medical attention other than first aid, damage to property of Owner or Contractor, and fires shall be orally reported to Owner at the time of the incident. Written reports, satisfactory in form and content to Owner shall be submitted by Contractor within forty-eight (48) hours after each incident.

9.4 Contractor shall maintain, in form and content approved by Owner, jobsite accident, injury and illness statistics which shall be available for inspection by, and submitted to, Owner upon its written request.

9.5 Contractor must complete Attachment B in Part I of this Contract, Contractor Safety Information / Checklist and maintain a current copy on file with Owner's Designated Representative.

9.6 Contractor shall provide and maintain adequate first-aid facilities and shall cooperate with all other contractors at the site and with Owner in their respective safety programs.

9.7 Contractor shall conform to all safety requirements set forth in Part II, Section 6.2 Safety Plan.

10. SUBCONTRACTS AND PURCHASE ORDERS

10.1 Contractor shall not subcontract performance of all or any portion of the Work under this Contract without first notifying Owner of the intended subcontracting and obtaining Owner acceptance in writing of the subcontracting and the subcontractor. Contractor shall submit its list of proposed subcontractors (utilizing Schedules E and F of Part III) to Owner's Designated Representative for approval. If requested by Owner, Contractor shall furnish Owner a copy of the proposed subcontract (with price deleted if the subcontracted work is part of fixed price Work of Contractor under this Contract) for Owner review of the terms and conditions thereof and shall not execute such subcontract until Owner has accepted such terms. Failure of Contractor to comply with this Section may be deemed by Owner to be a material breach of this Contract.

10.2 The general terms and conditions of this Contract and any Contract Amendment regarding the Work to be performed including but not limited to insurance requirements must be incorporated into and attached to any subcontract or assignment, subject to the conditions set forth in Part I Section 35 Insurance. Contractor guarantees that its subcontractors will comply fully with the terms of this Contract applicable to the portion of the Work performed by them. If any portion of the Work which has been subcontracted by Contractor is not prosecuted in accordance with this Contract, on request of Owner, the subcontractor shall be replaced at no additional cost to Owner and shall not be employed again on the Work.

10.3 Contractor shall include a provision in every subcontract that it places authorizing assignment of such subcontract to Owner without requiring further consent from such subcontractor or Contractor.

10.4 Owner shall have the right from time to time to contact Contractor's subcontractors to discuss their progress.

10.5 As used in this Contract, the term "subcontract" shall also include purchase orders and rental agreements for materials or equipment, and the term "subcontractor" shall also include vendors or Contractors of such material or equipment.

10.6 Contractor shall not be relieved of its responsibility for the Work by virtue of any subcontracts it may place regardless of Owner's acceptance of such subcontract.

11. TERMINATION FOR DEFAULT

11.1 The following actions by Contractor shall give Owner the right to terminate the Contract in whole or in part five (5) calendar days after Contractor's receipt of written notice.

(1) Contractor fails to carry forward and complete Work as rapidly as

required under the Contract specifying the Work, or if no deadlines are set in the Contract, as rapidly as Owner determines is required or that the circumstances will permit.

(2) Contractor fails to comply with applicable laws, regulations or ordinances.

(3) Contractor becomes involved in a labor problem which in the opinion of Owner impedes or slows down the Work.

(4) Contractor fails to commence correction of defective Work immediately after notification of the defect or as otherwise specified by Owner and to continuously and diligently pursue correction of the defect until the Work is completed to the full satisfaction of Owner.

(5) Contractor in any way breaches the material terms of this Contract.

(6) Contractor makes a general assignment for the benefit of its creditors.

(7) Contractor has a receiver appointed because of insolvency.

(8) Contractor files bankruptcy or has a petition for involuntary bankruptcy filed against him.

(9) Contractor fails to make prompt payments for materials or labor used in performance of the Work.

(10) Contractor fails to comply with Owner's safety standards.

11.2 It is agreed that if Owner exercises its right to terminate this Contract for any of the above reasons, the termination shall not prejudice any other right or remedy available to Owner.

11.3 Upon termination for cause of the Contract Owner may take control of the Work; take possession of all materials at the Work location which were intended for incorporation into the Work; and shall be allowed to utilize any of Contractor's equipment or tools at the site. Owner may complete the Work itself or hire another contractor to complete it. Contractor shall receive no further payments until all Work is completed. Upon completion, Contractor will be paid as follows:

(1) If the Contract provides for a fixed price, Contractor will be paid the unpaid balance remaining under the Contract less all reasonable costs and damages incurred in finishing the Work, including reasonable compensation for overhead, for administrative and managerial services and for any legal expenses incurred by Owner to affect the takeover and complete the Work. If Owner's reasonable costs exceed the unpaid balance, Contractors shall pay the difference to the Owner.

(2) If the Contract provides for Work to be undertaken on other than a fixed price basis, Contractor shall be liable to Owner for any reasonable differential between the rates agreed upon by Owner and Contractor for the Work and the new rates agreed upon by Owner and the replacement contractor or the cost to Owner for undertaking the Work itself, including reasonable compensation for overhead, for administrative and managerial

services, and for any legal expenses incurred by Owner. Contractor's liability for the differential shall apply until the completion of the authorized Work. In addition, if Owner incurs any other reasonable costs or damages as a result of the Contract termination, including but not limited to costs for additional hours worked due to mobilizing the replacement personnel, necessity of hiring less efficient replacement personnel, or replacing or repairing any part of the Work performed by Contractor prior to termination, Contractor shall be liable for these costs. Any outstanding balance payable to Contractor for Work performed prior to termination shall be paid, less the amounts specified above. If Owner's reasonable costs exceed the unpaid balance, Contractors shall pay the difference to the Owner and Contractor's liability shall be limited to the Contracts value.

(3) What costs are considered to be "reasonable" shall be determined based on conditions in existence when the costs or damages are incurred, including Owner's need to operate and dispatch the plant.

11.4 Contractor shall be allowed a credit by Owner at the agreed-upon prices (if applicable) for all materials purchased by Contractor and subsequently incorporated into the Work by a replacement contractor or Owner. If there are no agreed-upon prices for materials, Contractor shall be credited for the materials at actual cost. Contractor shall also be allowed a credit for the fair market rental value for any of Contractor's equipment or tools used to complete the Work.

11.5 If, after termination, it is determined that Contractor was not in default, or that the default was excusable, the rights and obligations of the parties shall be the same as if the Contract had been terminated for the convenience of Owner in accordance with the Termination for Convenience section set forth below.

12. <u>NOT USED</u>

- TIMING OF WORK -

13. <u>SCHEDULING, REPORTING AND COORDINATION</u>

13.1 Contractor shall schedule and coordinate the details of the Work being performed to meet the schedule requirements set forth in PART I of this Contract. Within thirty (30) calendar days after award of this Contract and before submittal of the first progress payment invoice, Contractor shall submit to Owner for approval, a detailed schedule showing the sequence in which Contractor proposes to perform the Work, the start and completion dates of all separable portions of the Work. Contractor will notify Owner Ninety (90) days prior to arrival of any material on site, and any other information specified by Owner. Contractor agrees to adhere to the schedule approved by Owner and attend and participate in scheduled progress and coordination meetings called by Owner.

13.2 During the performance of Work, Contractor shall submit to Owner periodic progress reports on the actual progress and updated schedules as may be required by this Contract or requested by Owner. In the event Contractor's performance of the Work is not in compliance with the schedule established for such performance Owner may, in writing, require the Contractor to submit its plan for schedule recovery, or specify in writing the steps to be taken to achieve compliance with such schedule, and/or exercise any other remedies under this Contract. Contractor shall thereupon take such steps as may be directed by Owner or otherwise necessary to improve its progress without additional cost to Owner.

13.3 Contractor recognizes that Owner, other contractors and subcontractors may be working concurrently at the jobsite. Contractor agrees to cooperate with Owner and other contractors so that the project as a whole will progress with a minimum of delays. Owner reserves the right to direct Contractor to schedule the order of performance of its Work in such manner as not to interfere with the performance of others.

13.4 If any part of Contractor's Work is dependent upon the quality and/or completeness of work performed under another contract, Contractor shall inspect such other work and promptly report to Owner any defects therein which render such work unsuitable for the proper execution of the Work under this Contract. Failure to make such inspections or to report any such defects to Owner shall constitute Contractor's acceptance of such other work as suitable to receive Contractor's Work provided however, that Contractor shall not be responsible for defects which could not have reasonably been detected.

14. <u>NOT USED</u>

15. <u>FORCE MAJEURE</u>

15.1 Any delays in performance by Owner or Contractor, shall not constitute a default hereunder if and to the extent such delays of performance are caused by occurrences beyond the reasonable control of Owner or Contractor, as the case may be, including but not limited to: acts of God or the public enemy; expropriation or confiscation of facilities; compliance with any order or request of any governmental authority; changes in law; act of war (declared or undeclared), hostilities or acts of terrorism; rebellion or sabotage or damage resulting therefrom; fires, floods, explosions, accidents; or any causes, whether or not of the same class or kind as those specifically above named, which are not within the control of Owner or Contractor respectively, and which by the exercise of reasonable diligence, Owner or Contractor, respectively, is unable to prevent or overcome. Contractor's scheduled completion date shall be adjusted to account for any force majeure delay. The affected party shall exercise all reasonable efforts to overcome and mitigate the effects of any force majeure event at its own cost.

15.2 Contractor shall, within five (5) working days of the commencement of any delay, give to Owner written notice thereof and of the anticipated effects thereof. Within two (2) working days of the termination of any delay, Contractor shall file a written notice with Owner specifying the actual duration of the delay. If Owner determines that a delay was beyond the control and without the fault or negligence of Contractor or its subcontractors and not foreseeable by Contractor at the effective date of this Contract, Owner shall determine the duration of the delay and shall extend the time of performance of this Contract thereby.

15.3 Contractor shall not be entitled to, and hereby expressly waives recovery of, any damages suffered by reason of delays of any nature, and extension of time shall constitute the Contractor's sole remedy for excusable delays.

16. POSSESSION PRIOR TO COMPLETION

Owner shall have the right to move into Contractor's working and storage areas and the right to take possession of or use any completed or partially completed part of Contractor's Work as Owner deem necessary for their operations. In the event Owner desires to exercise the foregoing right, Owner will so notify Contractor in writing. Such possession or use shall not constitute acceptance of Contractor's Work.

17. NOTICE OF COMPLETION AND FINAL ACCEPTANCE

17.1 When Contractor deems the Work fully completed, including satisfactory completion of such inspections, tests and documentation as are specified in this Contract, Contractor shall, within ten (10) working days thereafter, give a written Notice of Completion of the Work to Owner, specifying the Work completed and the date it was completed. Within thirty (30) calendar days after receipt of said Notice of Completion, Owner may inspect the Work and shall either reject the Notice of Completion and specify defective or uncompleted portions of the Work, or conditionally accept the Work either for the purpose of final payment only, or accept the Notice of Completion (reference Attachment L) for the purposes of final payment and final acceptance.

17.2 In the event Owner rejects the Notice of Completion and specifies defective or uncompleted portions of the Work, Contractor shall within five (5) working days provide for Owner review and approval a schedule detailing when all defects will be corrected and/or the Work will be completed and shall proceed to remedy such defective and uncompleted portions of the Work. Thereafter, Contractor shall again give Owner a written Notice of Completion of the Work, specifying a new date for the completion of the Work based upon the date such defective or uncompleted portions of the Work were corrected. The foregoing procedure shall apply again and successively thereafter until Owner has given Contractor written Notice of Acceptance (reference Attachment K) for purposes of final payment and final acceptance.

17.3 Any failure by Owner to inspect or to reject the Work or to reject Contractor's Notice of Completion as set forth above, shall not be deemed to be acceptance of the Work for any purpose by Owner nor imply acceptance of, or agreement with, said Notice of Completion.

17.4 Final acceptance of the Work by Owner shall not excuse any breach of this Contract and shall not constitute a waiver of any right or remedy under this Contract or at law.

- WORK CHANGES -

18. CHANGES

18.1 The Scope of Work shall be subject to Change by additions, deletions or revisions thereto by Owner. Contractor will be notified of such Changes by receipt of additional and/or revised drawings, specifications, exhibits or other written notification and Contractor shall notify Owner within seven (7) working days of receiving any revised or additional drawings if it believes such revisions constitute a change or else Contractor shall be deemed to have waived such claim.

18.2 Contractor shall submit to Owner within (7) seven working days after receipt of notice of a Change, a detailed takeoff with supporting calculations and pricing for the Change together with any requested adjustments in the schedule. The pricing shall be itemized as required by Owner and shall be in sufficient detail to permit an analysis of all labor, material and equipment and shall cover all work involved in the Change, whether such work was deleted, added or modified. Pricing shall be based on the rules set forth in Part III, Sections 4.0 and 5.0. Amounts related to subcontracts shall be supported in similar detail. In addition, if the proposal includes a time extension, justification therefore shall also be furnished.

18.3 Contractor shall not perform Changes in the Work in accordance with Sections 18.1 and 18.2 until Owner has approved in writing the pricing for the Change and any adjustment in the schedule for performance of the Work, except as set forth in Section 18.4. Upon receiving such written approval from Owner, Contractor shall diligently perform the Change in strict accordance with this Contract.

18.4 Notwithstanding Section 18.3 Owner may expressly authorize Contractor in writing to perform the Change prior to such approval by Owner. Contractor shall not suspend performance of this Contract during the review and negotiation of any Change, except as may be directed by Owner pursuant to Section 19B. In the event Owner and Contractor are unable to reach timely agreement regarding any Change, Contractor shall then comply with Section 20.0, CLAIMS.

18.5 Contractor is not authorized to proceed with any oral Changes in the Work. If Contractor believes that any oral notice or instruction received from Owner will involve a Change in the cost, time to perform or integrity of the Work, it shall require that the notice or instruction be given in writing and shall comply with the provisions of Sections 18.2, 18.3 and 18.4. Any costs incurred by Contractor to perform oral Changes shall be for Contractor's account, and Contractor waives any and all rights to claim from Owner for such costs or additional time to perform the Work as a result of compliance by Contractor with such oral Changes.

19. TERMINATION AT OWNER'S OPTION AND SUSPENSION OF WORK

A. Termination for Convenience

Owner shall have the right to terminate this Contract either in whole or in part at any time, including prior to commencement of any Work, for Owner's convenience. Upon receiving notice of termination, Contractor shall discontinue the Work on the date and to the extent specified in the notice and place no further orders for materials, equipment, services or facilities except as needed to continue any portion of the Work which was not terminated. Contractor shall also make every reasonable effort to cancel, upon terms satisfactory to Owner, all orders or subcontracts related to the terminated Work.

In paying Contractor for Work performed under this Contract that is terminated for Owner's convenience, Owner will make payments to Contractor as follows:

(1) If this Contract is terminated prior to Contractor's having commenced any Work or preparation for Work, no payment will be made to Contractor.

(2) If this Contract is terminated after the Contractor has commenced mobilization or other off-site activities but prior to any performance of the authorized Work, Owner will pay Contractor the actual cost, including administrative and general overhead, of any preparation to perform the authorized Work that cannot be recovered by Contractor in future Work done for Owner or otherwise. This paragraph does not apply to engineering, design, fabrication or other off-site Contractor expenditures that are actually part of the Work rather than preparation to perform the Work.

(3) If a Contract is terminated for Owner's convenience after commencement of the authorized Work, then except as provided in (4) below, Owner will pay Contractor for Work performed prior to termination as follows:

(a) For Work, including demobilization, under Contract where payment is on a unit price basis, or a time-and-materials basis, Contractor will be compensated at the rates specified in the Contract. If profit is included in the authorized rates no additional payments will be made for anticipated profits; if profit is not included in the rates, the amount paid will be increased by ten percent (10%) to account for profit. Notwithstanding the above, Owner will not pay for time worked by Contractor's employees which as a percentage of total anticipated hours to be worked unreasonably exceeds the percentage of Work completed prior to termination.

(b) Where Work is to be performed on a fixed-price basis, Contractor will be paid its reasonable actually incurred costs, including administrative and general overhead costs and demobilization costs, determined in accordance with generally accepted accounting principles consistently applied, plus an amount equal to ten percent (10%) of those costs to account for profit. Notwithstanding the above, Owner will not pay an amount for costs actually incurred which unreasonably exceeds the percentage of total costs as compared to the percentage of total work completed prior to termination. In no event will Owner pay Contractor an amount that exceeds the fixed price.

(4) If (1) at the time of termination Contractor has prepared or fabricated any goods or purchased or leased any materials or equipment intended for subsequent incorporation into the Work, and (2) these goods or materials cannot be incorporated into any other work for Owner or otherwise, then Contractor will be paid for the actual cost of the goods or materials.

(5) Contractor agrees that it has an affirmative duty to mitigate all damages to it upon termination of the Contract. In no event shall Owner be responsible to pay Contractor for its anticipated profits or any sales commissions or any special, indirect, incidental, or consequential damages of any kind or nature whatsoever.

(6) Contractor shall maintain adequate documentation to support its claim for payment. Any part of Contractor's claim that is not supported by adequate documentation will not be paid by Owner. Payment of the amounts specified above shall be Contractor's sole and exclusive remedy for termination of Work for Owner's convenience.

B. Suspension of Work

Owner may, for any reason, elect to temporarily suspend performance of any or all of the Work to be performed under this Contract for a period of time as specified by Owner's Designated Representative. Contractor shall be informed of Owner's desire to suspend the Work by either receipt of a written directive or a verbal directive followed by a written confirmation from Owner's Designated Representative within three (3) working days of the verbal directive. Upon receipt of this directive, Contractor shall immediately cease all efforts to perform the Work or that part of the Work which is suspended. Demobilization of Contractor's personnel and equipment from Owner's Work site shall be in accordance with Owner's directive. Contractor shall resume performance in accordance with the written directive of Owner's Designated Representative. Except as hereinafter provided, the time for completion of the suspended Work will be extended by a Contract Amendment for a period of time not to exceed the period of suspension.

Within ten (10) calendar days from reinstatement of the Work, Contractor shall notify Owner in writing of any equitable adjustment it deems necessary to the price because of the suspension. These claims must be itemized and supported with adequate documentation. Increases in compensation resulting from suspension must be agreed upon by both parties in a Contract Amendment. Unless Contractor is required by Owner's written directive to maintain affected personnel and equipment on Owner's Work site, increases in compensation shall be limited to charges and costs directly related to mobilization of personnel and equipment.

If Owner suspends the Work for any of the reasons specified in Section 11.0, TERMINATION FOR DEFAULT, then no additional compensation will be paid by Owner, and the time for completion of the Work will not be extended.

20. CLAIMS

Contractor shall give Owner written notice within five (5) working days after the happening of any event which Contractor believes may give rise to a claim by Contractor for additional time or money. Within ten (10) working days after the happening of such event, Contractor shall supply Owner with a statement supporting Contractor's claim, including but not limited to, Contractor's detailed estimate of the Change in Contract Price and scheduled time occasioned thereby.

Contractor shall substantiate its claim with payroll documents, paid invoices, receipts, records of performance and other documents satisfactory to Owner and subject to its verification. Owner shall not be liable for, and Contractor hereby waives, any claim or potential claim of Contractor which was not reported by Contractor in accordance with the provisions of this Section. The parties shall negotiate diligently to reach an agreement, but in no case, except with Owner prior written consent, shall any Work be halted pending such agreement, whether or not the claim can be resolved to Contractor's satisfaction, and Contractor shall be bound by the terms and conditions of this Contract to prosecute the Work without delay to its successful completion. Any claim that is not resolved within a reasonable time shall be subject to the provisions of Section 21, Dispute Resolution. Owner shall not be bound to any adjustments in the Contract Price or scheduled time unless expressly agreed to by Owner in writing. No claim hereunder by Contractor shall be allowed if asserted after final payment under this Contract. Contractor's remedies are limited to those expressly set forth in this Contract.

21.0 DISPUTE RESOLUTION

In the event of any dispute under this Contract which cannot be readily resolved, it shall be referred to the appropriate executives of the respective Parties for negotiation and resolution as described below:

a. Either Party may give the other Party written notice of any dispute not resolved in the normal course of business. Executives of both Parties who have not previously been involved in the dispute shall meet at a mutually acceptable time and place within thirty (30) Days after delivery of such notice and thereafter as often as they reasonably deem necessary, to exchange relevant information and to attempt to resolve the dispute. If the matter has not been resolved by these persons within sixty (60) Days of the disputing Party's notice, or if the Parties fail to meet within thirty (30) Days, the Parties may agree to an alternative dispute resolution procedure, or either Party may commence appropriate legal proceeding to resolve the dispute.

b. All negotiations pursuant to this Section shall be confidential and shall be treated as compromise and settlement negotiations for purposes of the Federal Rules of Evidence and State Rules of Evidence.

c. If the dispute has not been resolved by negotiation as provided herein, the Parties may by mutual written consent attempt to settle the dispute by mediation. Any such proceeding will be conducted in accordance with the then current Center for Public Resources ("CPR") Model Procedure for mediation of Business Disputes, with the following exceptions:

    1. if the Parties have not agreed within thirty (30) Days of the agreement to mediate on the selection of a mediator willing to service, the CPR, upon the request of either Party, shall appoint a member of the CPR Panels of Neutrals as the mediator; and

    2. efforts to reach a settlement will continue until the conclusion of the proceeding, which is deemed to occur when: (a) a written settlement is reached, or (b) the mediator concludes and informs the Parties in writing that further efforts would not be useful, or (c) the Parties agree in writing that an impasse has been reached. Neither Party may withdraw before the conclusion of the proceeding.

d. All applicable statues of limitation and defenses based upon the passage of time shall be tolled while the executive meetings and mediation procedures specified in this Section are pending. The Parties will take such action, if any, required to effectuate such tolling.

- MATERIALS AND EQUIPMENT -

22.0 <u>NOT USED</u>

23.0 <u>OWNER'S TOOLS, MATERIALS AND EQUIPMENT</u>

Contractor shall equip all employees with all tools and equipment necessary to perform the Work unless otherwise expressly provided in this Contract. All tools and equipment belonging to Contractor or its employees shall be clearly marked as to their owner. Contractor shall provide storage facilities for all tools and equipment at or near the job site. Storage facilities on the site shall be located in a place approved by Owner's Designated Representative.

All materials, tools and equipment furnished by Owner shall remain its property. Contractor agrees not to use Owner-supplied materials, tools or equipment for any purpose other than Work for which these items were supplied, unless written permission is given in advance by Owner's Designated Representative. Contractor shall reimburse Owner at Owner's replacement cost plus a factor to cover current administrative and general overhead costs for all materials, tools or equipment placed in Contractor's possession which are not included in the completed Work or returned to Owner in kind. When requested in writing, Contractor agrees to purchase special equipment or tools or furnish them on a rental basis. The purchase price or rental cost of such equipment and/or tools and the basis of payment will be as agreed upon, if not previously established in the Contract Rate Schedule. Any tools specifically purchased for authorized Work and paid for by Owner are the property of Owner and shall be turned over to Owner upon completion of the Work.

24.0 RESPONSIBILITY FOR WORK

Contractor is responsible for and shall bear all risk of loss or damage to Work, and all materials, tools and equipment delivered to the Work location by Contractor or its subcontractors, until completion by Contractor and final acceptance of Work by Owner, unless the loss or damage to the Work results solely from the negligence of Owner. Owner is not responsible for any loss or damage to the Work, or to materials, tools and equipment of Contractor resulting from any act or omission of any other contractor.

Contractor shall be responsible, at no additional cost to Owner, for taking all precautions necessary to prevent damage or injury to the Work of Contractor, Owner or its contractors, and to the property of Contractor, Owner, other contractors, or any of their employees, and members of the general public. These measures shall include, but not be limited to laying dropcloths, constructing shields and guard fences, and any other precautionary measures Owner may direct.

Asbestos Containing Material (ACM) shall not be used by Contractor or his subcontractors in any Work performed under this Contract unless specifically agreed to in writing by Owner's Designated Representative prior to the start of the Work

When the Contractor's supervision is not present on any part of Owner's premises where it becomes necessary to give directions in an emergency, orders may be given by Owner's Designated Representative and shall be received and obeyed by Contractor's personnel. If requested to do so, Owner shall confirm such orders in writing.

The use of explosives in a manner which disturbs or endangers the stability, safety or quality of the Work or of Owner or third-party property will not be allowed.

25.0 CONTRACTOR'S CONSTRUCTION EQUIPMENT

Construction equipment obtained or furnished by Contractor which is to be used by Contractor on the jobsite shall be in first-class operating condition, safe, fit for the uses for which intended, and suitable for the safe, legal and efficient performance of the Work. Such equipment shall be subject to inspection from time to time by Owner. Any such equipment of Contractor which is rejected by Owner as not conforming with the foregoing shall be promptly removed by Contractor and replaced with equipment acceptable to Owner, without additional cost to Owner and without delaying the schedule for performance of the Work by Contractor.

26.0 CONTRACTOR'S SHIPMENTS

26.1 Contractor shall be responsible for arranging all shipments of Contractor supplied materials and equipment to the site of the Work and shall consign such shipments to itself as Consignee at the project shipping address, freight fully prepaid. Contractor shall be responsible for making demurrage agreements and settlement with carriers for its shipments.

26.2 Contractor shall advise Owner in writing in advance of major shipments of Contractor's materials and equipment and shall coordinate with Owner the arrival, unloading and release of carriers' equipment. Contractor shall promptly unload its shipments and promptly release carrier's equipment.

26.3 In the event Contractor is unable to promptly unload its shipment, Contractor shall notify Owner of such inability not less than ten (10) working days in advance of arrival. Owner, at its option, may unload or make arrangements for others to unload such shipments for the account and risk of Contractor. Contractor will promptly pay Owner for such costs of unloading.

27.0 CONTROL OF OWNER FURNISHED MATERIALS

27.1 Materials and equipment furnished by Owner shall be received by Contractor in the presence of Owner authorized representative and quantities thereof shall be checked jointly by Contractor and Owner. The delivery and acceptance of all such materials and equipment shall be recorded in writing, and Contractor shall evidence receipt and acceptance of such materials and equipment by signing forms satisfactory to Owner.

27.2 Contractor shall carefully note any visible damage to Owner furnished materials and equipment prior to Contractor's acceptance of delivery. After Contractor has accepted delivery of such materials and equipment, Contractor shall assume full responsibility for any loss of or damage to such materials and equipment. Contractor shall notify Owner of any materials and equipment supplied to Contractor by Owner which are surplus and, without additional compensation, shall cooperate with Owner in the disposition of such surplus as directed by Owner.

27.3 Contractor shall notify Owner of any lack of, or requirement for, materials and equipment required under this Contract to be supplied by Owner in sufficient time for Owner to furnish said materials or equipment in advance of Contractor's need. In the event of misfit of Owner furnished materials or equipment, Contractor shall promptly notify Owner of such misfit. Contractor shall take all reasonable steps to avoid standby time due to such misfit or lack of Owner furnished materials or equipment and to continue progress of other portions of Work pending correction of such misfit and/or the furnishing of materials or equipment.

28.0 CARE, CUSTODY, CONTROL AND TITLE TO MATERIALS AND EQUIPMENT

28.1 Good and clear title to all materials and equipment furnished by Contractor under this Contract for the Work shall, except as expressly provided otherwise, elsewhere in this Contract, pass to Owner upon receipt of payment for those materials. Contractor shall ensure that subcontractors from whom Contractor obtains materials and equipment do not retain, encumber or reserve title to such items, and Contractor shall defend, indemnify and hold Owner harmless from any such claims by its subcontractors.

28.2 Notwithstanding the provisions of Section 28.1, the care, custody and control of Contractor's Work incorporated into the permanent plant shall remain with Contractor until such Work has been accepted in writing by Owner and shall thereupon pass to Owner unless Owner notify Contractor in writing that such care, custody, and control is assumed by Owner at an earlier date. The taking of possession of such Work pursuant to Section 16.0, POSSESSION PRIOR TO COMPLETION, shall not constitute the assumption of care, custody and control of such Work until such time as such Work has either been accepted in writing by Owner or Contractor has been notified as set forth herein.

28.3 Contract revenues representing payments to subcontractors shall not be considered to be earned by Contractor unless and until Contractor has paid the current invoices of such subcontractor. In the event Owner determines, in its sole discretion, that Contractor has become insolvent or is in danger of becoming insolvent, then Owner is authorized, but not required, to make direct payment to Contractor's subcontractors with respect to any current or past-due invoices then outstanding. Alternatively, Owner may, in its sole discretion, require that contracts between Contractor and any such subcontractor be assigned to Owner, and Contractor hereby authorizes and consents to any such assignment. Owner shall be entitled to full credit against any obligations to Contractor for any payments made to any subcontractor under this Section 28.3, whether made pursuant to assigned subcontracts or otherwise. Title to any materials or equipment for which such direct payment is made shall pass directly from such subcontractor to Owner.

29.0 CLEAN UP

Contractor shall be responsible for keeping the area where its employees and subcontractors are working clean at all times. If Contractor fails or refuses to maintain a clean Work area, Owner may perform or arrange to have performed a cleanup of the area. If Owner incurs any cost performing cleanup of Contractor's Work, that cost times a factor sufficient to cover Owner's then applicable administrative and general overhead costs shall be paid to Owner or may be deducted by Owner from any amount owed to Contractor.

Upon completion of identifiable segments of Work, Contractor is to remove all waste or debris from its Work area unless the waste or debris is subject to the conditions set forth with Subsection titled, "Environmental Provisions" of the Section titled, "Regulatory Compliance Issues". Contractor is responsible for restoring its Work area and any areas affected by its Work to at least as good an order and condition as the area was in prior to commencing the Work unless the restoration would conflict with Subsection titled, "Environmental Provisions" of the Section titled, "Regulatory Compliance Issues". See site Rules in Attachment C in Part II of this Contract.

- LABOR AND WORK RULES -

30.0 CONTRACTOR'S PERSONNEL

Personnel provided by Contractor under this Contract shall at all times remain the sole responsibility of said Contractor for purposes of personal and professional liability. Attachment P – "Contractor's Organizational Chart" shows the key design and management personnel critical for the performance of this Work. Contractor shall not change these personnel unless agreed to, in writing, by Owner.

All personnel to be provided by Contractor under this Contract shall be employees of Contractor and shall not be independent contractors. Contractor shall withhold from each employee's pay sufficient funds for federal, state and local income taxes as required by applicable laws, funds required by the Federal Insurance Contributions Act, and as may otherwise be required by applicable law. Contractor further agrees to defend, indemnify, and hold Owner harmless from any claims, fines and penalties based on any allegations that such withholdings were not made, or that such withholdings were inadequate.

Contractor is solely responsible for all aspects of the labor relations of its personnel, including but not limited to, wages, benefits, discipline, hiring, firing, promotions, pay raises, overtime and job and shift assignments. Owner shall have no responsibility for or power over these areas. Such personnel shall be and remain the employees of Contractor at all times.

Contractor shall comply with the Fair Labor Standards Act, and shall pay overtime to its employees as required by all applicable federal, state and local laws, rules, regulations, and ordinances. In the event that Contractor fails to comply with this requirement, Contractor shall be required to indemnify, defend and hold Owner harmless from all claims, actions, fines, penalties, and liabilities resulting from any such failure.

In selecting employees to undertake any Work, Contractor shall select only those persons who are qualified by the necessary education, training and experience to provide a high quality performance of the Work. If Owner determines, in its sole discretion, that any personnel or subcontractor supplied by Contractor are unsuitable for the Work, Owner shall so advise Contractor and Contractor shall remove that employee or subcontractor from the premises and assign other individuals to perform the Work. If Owner determines, in its sole discretion, acting reasonably, that the presence on Owner's premises of any employee of Contractor is not consistent with the best interest of Owner, Owner may direct Contractor to remove that employee from performing Work under this Contract. Contractor shall assign another employee to work in place of the unacceptable employee. Replacement of employees under either of the above circumstances shall be at no cost to Owner. Contractor shall absorb any travel costs or travel time to the site for the replacement employee and from the site for the replaced employee. Contractor shall give Owner advance notice prior to removing Contractor's supervisory or professional personnel from the job.

Contractor's employees' vehicles and Contractor's vehicles and equipment shall be parked in areas expressly approved by Owner's Designated Representative, when parking on Owner owned or controlled property.

Contractor's employees and subcontractors shall be properly dressed to Owner's standards at all times while on Owner's Work site. Employees not properly dressed will be refused entry to or will be subject to discharge from the Work site.

Contractor shall secure from each employee and subcontractor, prior to that employee's arrival at any Owner Property:

(a) the employee's agreement to abide by Owner's Fitness-for-Duty Policy, as set forth in Section 62;

(b) the employee's consent to a search or inspection of the employee and the employee's property, including the employee's vehicle and closed containers within the vehicle, upon admission to and departure from any Owner facility and at any time while on Owner Property;

(c) the employee's agreement to abide by all Owner security practices and procedures as set forth in Section 61.

Use of Non-English Speaking Workers

Prior to the beginning of any task under this contract, the Contractor shall notify Owner if it anticipates using any non-English speaking personnel at Owner's facilities. If such personnel are used, the Contractor shall provide an on-site bilingual person to translate the site orientation and safety information training. Contractor shall be solely responsible for ensuring that the non-English-speaking workers are fully trained and understand the site orientation and safety information. In addition, any time the Contractor's non-English speaking workers are present at a Owner facility, the Contractor shall provide at least one bilingual person in each applicable work crew capable of both communicating in English and instructing the non-English speaking workers. The Contractor shall specifically identify these bilingual interpreters to Owner Designated Representative. For this purpose, a work crew is defined as any worker or group of workers in any specific location on Owner property, regardless of how the Contractor organizes his work force.

Owner may assist in facilitating communication of important safety information by offering bilingual versions of safety brochures or video presentations. If these are available, it in no way relieves the Contractor of providing the interpreter services stated above.

31.0 LABOR HARMONY

Contractor agrees that all labor employed by it, its agents, and/or subcontractors for Work on the jobsites shall be in harmony with and be compatible with all other labor used by Owner or other Contractors. Whenever Contractor has knowledge that any actual or potential labor dispute is delaying or threatens to delay the timely performance of the Work, Contractor shall immediately give notice thereof including all relevant information to Owner.

32.0 EMPLOYMENT CERTIFICATIONS AND PRACTICES

Contractor certifies that it has an affirmative action policy ensuring equal employment opportunity without regard to race, color, national origin, sex, age, religion or handicap, that it maintains no employee facilities segregated on the basis of race, color, religion or national origin and that it is not debarred or suspended from being awarded Federal or Federally assisted contracts.

33.0 NOT USED

- INDEMNIFICATION AND INSURANCE -

34.0 INDEMNITY

To the maximum extent permitted by applicable law, Contractor shall indemnify and defend OWNER (including its parent, subsidiary and affiliate companies), its officers, employees, agents, and any other party with an ownership interest in the premises, from and against all liability, loss, costs, claims, damages, expenses, judgments, and awards, whether or not covered by insurance, arising or claimed to have arisen:

(a) from and to the extent of negligent acts or omissions of, or as a result of Work done or omitted from being done, or as a result of negligence by Contractor, its subcontractors or assignees and their agents or employees, which resulted in:

(1) injury to (including mental or emotional) or death of any person, including employees of Owner (including its parent, subsidiary and affiliate companies), or

(2) damage to or destruction of any property, real or personal, including without limitation property of Owner (including its parent, subsidiary and affiliate companies) and its other contractors, Owner's (including its parent, subsidiary and affiliate companies') employees, and fellow employees;

(b) out of injuries sustained and/or occupational diseases contracted by Contractor's, subcontractor's, or assignee's employees, if any, of such a nature and arising under such circumstances as to create liability by Owner (or its parent, subsidiary or affiliate companies) or Contractor under the Workers' Compensation Act, and all amendments thereto, of the state having jurisdiction, including all claims and causes of action of any character against Owner (and its parent, subsidiary and

affiliate companies) by any employee of Contractor, its subcontractors or assignees, or the employer of such employees, or any person or concern claiming by, under or through them resulting from or in any manner growing out of such injuries or occupational diseases; and

(c) from demands, actions or disputes asserted by any subcontractors, employees or suppliers of Contractor.

Indemnification shall include all costs including attorney's fees reasonably incurred in pursuing indemnity claims under or enforcement of this Contract.

To the maximum extent permitted by applicable law, Contractor shall indemnify and defend Owner (including its parent, subsidiary, and affiliate companies), its officers, employees, agents, and the architect/engineer and any other party with an ownership interest in the premises, from and against all liability, loss, costs, claims, damages, expenses, judgments, and awards, whether or not covered by insurance, arising or claimed to have arisen.

Notwithstanding the foregoing, Contractor's indemnification obligations shall be limited to the extent of Contractor's negligence or willful misconduct or that of its subcontractor's or anyone else Contractor is liable for, and Contractor shall NOT be required to protect, indemnify or hold harmless the Owner Indemnities from any claims to the extent such claims are due to Owner Indemnities willful misconduct or neglect.

35.0 INSURANCE

General

35.1 Contractor shall, at its own expense, maintain in effect at all times during the performance of the Work insurance coverage with limits set forth below with insurers and under forms of policies satisfactory to Owner. It shall be the responsibility of Contractor to maintain adequate insurance coverage and to assure that Subcontractors are adequately insured at all times. Failure of Contractor to maintain adequate coverage shall not relieve Contractor of any contractual responsibility or obligation.

35.2 The requirements specified herein as to types and limits of insurance coverage to be maintained by Contractor and its Subcontractors are not intended to and shall not in any manner limit or qualify the liabilities and obligations assumed by Contractor and its Subcontractors under this Contract.

35.3 Any insurance carried by Owner which may be applicable shall be deemed to be excess insurance and Contractor's insurance shall be primary for all purposes despite any conflicting provision in Contractor's policies to the contrary.

35.4 Certificate of Insurance.

1. At the time of execution of this Contract and each subcontract, but in any event prior to commencing work at the Jobsite, and as a condition precedent to Contractor's and its Subcontractors' initiation of performance, and prior to payment of any invoices, Contractor and its Subcontractors of any tier shall furnish Owner with certificates of insurance as evidence that policies providing the required coverage and limits of insurance are in full force and effect. The certificates shall provide that any Owner issuing an insurance policy for the Work under this Contract shall provide not less than thirty (30) days' advance notice in writing to Owner prior to cancellation, termination or material change of any policy of insurance. In addition, Contractor shall immediately provide written notice to Owner upon receipt of notice of cancellation of an insurance policy or a decision to terminate or materially alter an insurance policy.

2. All certificates of insurance shall be completed by Contractor's insurance carrier and shall clearly state that the Contractor carries the requisite insurance and that said policies satisfy all applicable requirements including insurance for the liabilities assumed by Contractor under Section 34, Indemnity. Certificates covering general liability and umbrella liability insurance shall indicate that these policies are "occurrence" type. Duplicate copies of certificates of insurance for Contractor- and Subcontractor-furnished insurance and notices of any cancellations, terminations or alterations of such policies shall be mailed to Owner.

3. Contractor shall provide copies of the complete policies to Owner, if requested.

4. No payment shall be made to Contractor prior to receipt by Owner of an acceptable Certificate of Insurance.

35.5 Insureds.

1. All insurance coverage furnished by Contractor under this Contract, with the exception of Workers' Compensation and Employers' Liability coverage, shall include Owner, its parent companies, and their directors, officers, agents, shareholders, and employees as additional insureds and all of Owner's parent, subsidiary, and affiliate companies to Contractor's liability insurance policies as additional insureds. Contractor shall require its insurance carrier or agent to certify that this requirement has been satisfied on all Insurance Certificates issued under this Contract.

2. These policies shall contain a "cross liability" or "severability of interest" clause or endorsement. Notwithstanding any other provision of these policies, the insurance afforded shall apply separately to each insured, named insured, or additional insured with respect to any claim, suit, or judgment made or brought by or for any other insured, named insured, or additional insured as though a separate policy had been issued to each, except the insurer's liability shall not be increased beyond the amount or amounts for which the insurer would have been liable had only one insured been named.

3. Owner shall not by reason of their inclusion under these policies incur liability to the insurance carrier for payment of premium for these policies, or incur liability to Contractor for payment of any policy retentions or deductibles.

35.6 Waiver of Subrogation.

1. Contractor and Owner shall require their insurance carriers, with respect to all insurance policies, to waive all rights of subrogation against each other and their directors, officers, officials, agents, subcontractors, shareholders, and employees.

2. Contractor and Owner and their insurers waive all rights of subrogation against each other and their directors, officers, officials, agents, subcontractors, shareholders, and employees for damages covered by the Builder's Risk insurance during the completion of the Work and covered by property insurance during the waived period.

35.7 Contractor shall provide and maintain in full force and effect, at no additional cost to Owner for the duration of the Contract, the following amounts of insurance:

1. Workers' Compensation and Employer's Liability. This insurance shall protect Contractor against all claims under applicable state workers' compensation laws. Contractor shall also be protected against claims for injury, disease, or death of employees which, for any reason, may not fall within the provisions of a workers' compensation law. This policy shall include an "all states" or "other states" endorsement.

The liability limits shall not be less than:

Workers' Compensation	Statutory.
Employer's Liability Minimum Limit	$1,000,000 (each occurrence)

2. Comprehensive Automobile Liability. This insurance shall be written in comprehensive form and shall protect Contractor and the additional insureds against all claims for injuries to members of the public and damage to property of others arising from the use of motor vehicles, and shall cover operation on or off the Jobsite of all motor vehicles licensed for highway use, whether they are owned, non-owned or hired.

The minimum liability limits shall be:

Bodily Injury and Property Damage	$1,000,000 combined single limit each occurrence and in the aggregate.

3. Commercial General Liability. This insurance shall be an "occurrence" type policy written in comprehensive form and shall protect Contractor and the additional insureds against all claims arising from bodily injury, sickness, disease or death of any person or damage to property of Owner or others arising out of any act or omission of Contractor or its Subcontractors, agents or employees. This policy shall also include protection against claims insured by usual personal injury liability coverage, a "contractual liability" endorsement to ensure the contractual liability assumed by Contractor under Section 34 Indemnity, and "Completed Operations and Products Liability" coverage (to remain in force for two (2) years after Commercial Operation).

   The minimum liability limits shall be:

   Bodily Injury and Property Damage each occurrence $1,000,000 ; aggregate $2,000,000

   If Contractor's Work, or Work under its direction, requires blasting, explosive conditions, or underground operations, the commercial general liability coverage shall contain no exclusion relative to blasting, explosion, collapse of structures or damage to underground property.

4. Umbrella Liability Policy. This insurance shall protect Contractor and the additional insureds against all claims in excess of the limits provided under the employer's liability, comprehensive automobile liability, and commercial general liability policies. The minimum liability limits of the umbrella liability policy shall be $20,000,000 per occurrence. The policy shall be an "occurrence" type policy.

5. Builder's Risk Insurance. Owner provide "All Risk" Builder's Risk Insurance including windstorm, earthquake and flood perils.

   This insurance will cover at the Jobsite, the actual physical construction itself, the Work installed, and construction materials, fixtures, supplies, machinery and equipment (other than construction machinery and equipment owned or leased by Contractors, Subcontractors and/or their employees) to be incorporated into the physical construction, charged to the project and only while stored at the Jobsite. In instances where the claim against the Builder's Risk policy is due to the negligence, willful misconduct, or strict liability of Contractor or its subcontractors, Contractor shall be responsible for the deductible and all costs and damages not covered by the Builder's Risk insurance policy. Owner is otherwise responsible for Builder's Risk deductible.

The Builder's Risk Policy shall include:

- Policy shall include all risk coverage including losses during testing/commissioning, due to flood, windstorm, or earthquake.

- Policy minimum limits of full Contract value plus the value of any owner-furnished equipment and materials that will be permanently incorporated into the project.

- Coverage for inland transportation including inland waterways of all equipment and materials to the job-site from anywhere in the Continental United States and Canada, including coverage while stored off-site.
- Coverage for resultant damage due to faulty design or construction.
- Waiver of subrogation against the Contractor, including all of its affiliates and subsidiaries and all employees, agents and other contractors of Contractor.
- Cost of opening/closing/gaining access to damaged equipment-coverage.

Exclusions from such insurance are, but not limited to, the following:

- Loss from mysterious disappearance or caused by any wrongful removal of any property of a named insured or any additional insured by the employee(s) of said named insured or additional insured.
- Loss or damage to any automobiles, vehicles (highway or otherwise), mobile equipment, cranes, hoists, and rolling stock.
- Cost of making good faulty workmanship, materials, construction, or design.
- Loss of or damage to Contractor's tools or equipment which are not specifically charged to the project and to become a part of the completed project.
- Loss of use or occupancy, however caused, or penalties for delay in completion or noncompliance with contracts.
- Loss or damage covered by a manufacturer's warranty or guarantee.

The foregoing represents only certain general conditions of a Builder's Risk Policy. The exact terms of the coverage are set forth only in the policy itself, a full copy of which will be made available to the Owner.

6. Other Insurance. Contractor and Subcontractors of any tier shall maintain the option to either self-insure or to procure insurance for damage to their owned and leased property including property onsite. Contractor and Subcontractors of any tier shall retain risk of loss for any damage whatsoever to their own equipment, stationary or mobile, tools, supplies, materials, automobiles and vehicles, highway or otherwise, cranes, and hoists or any other property owned or leased which shall not be incorporated into the physical construction.

   If separate insurance is maintained for any property described in this Section, it shall contain a Waiver of Subrogation on the part of the insurance in favor of Owner including all of its affiliates and subsidiaries and all employees and agents and all other contractors and subcontractors of any tier. If Contractor or Subcontractors of any tier choose to self-insure any of the property described under this Section, it is agreed that Owner and all other contractors and subcontractors of any tier shall be held harmless for any loss or damage to the property described under this Section.

7. Subcontractor Insurance. Before permitting any subcontractors to perform Work at the Jobsite, Contractor shall obtain a Certificate of Insurance from such Subcontractor evidencing that such subcontractor has obtained insurance as specified in Sections 35.1, 35.2; 35.3, 35.4 35.5, 35.6, and 35.7 1-4 above. If subcontractors cannot meet these insurance requirements, then Contractor shall hold responsibility for the additional levels of coverage.

36.0 NOT USED

37.0 NOT USED

- WORK CONDITIONS -

38.0 NOT USED

39.0 PERMITS, LICENSES AND TAXES

The Work performed under this Contract qualifies for both the Florida Steam Tax Exemption and the Florida Pollution Control Tax Exemption, as defined below.

Owner holds a "Florida Steam Tax Exemption Affidavit." This certificate exempts Owner from Florida sales or use tax on purchases of all qualified property and/or labor. The appropriate affidavit is hereby furnished to Contractor for use on this Contract only (Attachment N). Therefore, on qualified property and/or labor Contractor shall not include sales or use tax in the Contract price or on its invoices to Owner. This exemption should be used only for material or equipment used specifically for energy production.

Owner holds a "Florida Pollution Control Affidavit." This certificate exempts Owner from Florida sales or use tax on purchases of all qualified property and/or labor. The appropriate affidavit is hereby furnished to Contractor for use on this Contract only (Attachment O). Therefore, on qualified property and/or labor Contractor shall not include sales or use tax in the Contract price or on its invoices to Owner. This exemption should be used only for material or equipment used specifically for pollution control.
Unless otherwise stated in the Contract Documents, the Contractor shall apply for and obtain all licenses, permits, or other approvals from any governmental or regulatory body which are necessary to perform the Work contracted for herein. Contractor shall be responsible for any cost incurred in obtaining said licenses, permits, or approvals. Contractor shall obtain and maintain and shall require all Subcontractors to obtain and maintain all appropriate professional registrations, licenses, and special permits which are necessary to enable it and its Subcontractors to perform the Work.

40.0 INDEPENDENT CONTRACTOR

Nothing in this Contract shall be deemed to represent that Contractor or any of Contractor's employees or agents, are the agents, representatives or employees of Owner. Contractor shall be an independent contractor and shall have responsibility for and control over the details and means for performing the Work, provided that Contractor is in compliance with the terms of this Contract. Anything in this Contract which may appear to give Owner the right to direct Contractor as to the details of the performance of the Work or to exercise a measure of control over Contractor shall mean that Contractor shall follow the desires of Owner only as to the intended results of the Work.

41.0 CONFIDENTIAL INFORMATION

The terms of this contract and all Amendments to it or Work Authorizations issued under it are to remain confidential and shall be not provided in any form to any other party except upon order of a regulatory body or a court of competent jurisdiction.

Contractor agrees that if access is granted to Owner's computer network or a segment thereof, that this access is solely for the business purpose(s) described in this Contract. Contractor agrees that access for any other purpose or the use of Owner's computer network to access other networks, is strictly forbidden and that Contractor is responsible and liable for all damages or unauthorized access resulting from these actions. This activity will result in the discontinuation of any and all network connections, and Contractor understands that it may be subject to civil and/or criminal prosecution. Contractor further agrees that any information that it obtains from Owner's computer network is subject to all of the terms and conditions of this Contract.

Any program, document, data or information supplied by Contractor to Owner may be used, copied or disclosed by Owner as necessary in the normal course of its business, notwithstanding any copyright of Contractor in such materials and notwithstanding any notices or legends appearing thereon, unless otherwise agreed in the applicable Work Authorization.

Drawings, specifications, and other information obtained by Contractor from Owner in connection with the Work shall be held in confidence by Contractor and shall not be disclosed to third parties or used by Contractor for any purpose other than for the performance of Work or as authorized in writing by Owner. All such documents furnished by Owner to Contractor shall remain their property, and upon completion of the Work Contractor shall, as requested by Owner, either destroy or return such documents including any copies thereof.

Materials which are reviewed by Contractor in the course of the Contract may contain trade secrets which are the property of Owner or which have been loaned, licensed, purchased, or leased for Owner's use. Contractor agrees not to reveal any trade secret material which has been marked by Owner to any person in any form and further agrees not to use the material for itself for any purpose not connected with this Contract.

42.0 DELIVERABLES

Drawings, specifications and other documentation prepared by the Contractor as the work product under this Contract, as well as the Tower and any materials procured and delivered in performance of this Contract (the "Deliverables") shall become the property of the Owner, and shall be delivered to Owner as a part of the Work. Contractor shall mark any Contractor owned property as proprietary and/or confidential only where the release of such information would be injurious to Contractor or would otherwise impair the competitiveness of the Contractor.

Notwithstanding any other provision of this Section, there shall be no restriction on Owner's copying, use or disclosure (including to third parties) of Deliverables to the extent such use or disclosure is:

a. required by Owner for the supply, construction, installation, operation, inspection, and/or maintenance, replacement, modification and/or expansion of Owner's facilities, or
b. necessary to secure or maintain in effect any license or permit from any applicable government authority; or
c. required pursuant to an order of a court of competent jurisdiction, a request of any legal requirement.

If Owner intends to disclose Contractor's confidential information to any governmental agency or to a court or pursuant to any other legal requirement, Owner shall, to the extent it does not violate any such order or unduly delay or interfere with Owner's operations, advise the Contractor prior to disclosure and cooperate in any reasonable effort by the Contractor to minimize the amount of confidential information disclosed, secure confidential treatment of such confidential information, or seek permission of such governmental agency or court to revise the confidential information in a manner consistent with the Contractor's interest, the interests of Owner, and in a manner that meets the requirements of the governmental authority or court.

Except as otherwise provided in this Section with respect to Deliverables, Owner agrees not to knowingly reveal any other clearly designated proprietary information of the Contractor ("Non-Deliverable Proprietary Information") to any person in any form, and further agrees not to make any use of such Non-Deliverable Proprietary Information of the Contractor for any purpose not connected with or permitted by this Contract. Non-Deliverable Proprietary Information of the Contractor is disclosed to Owner in confidence, and shall be clearly designated in writing as proprietary and/or confidential. Contractor agrees not to mark any information as proprietary and/or confidential unless the release of such information would be injurious to Contractor or would otherwise impair the competitiveness of the Contractor.

The provisions set forth above shall not apply to (a) information that Recipient can show by cogent evidence was already in Recipient's possession at the time of disclosure by the Disclosing Party; (b) information that is generally available in the public domain other than as a result of a breach of this Agreement; (c) any information which was received in good faith from an independent source without knowledge of any obligation of non-disclosure to the Disclosing Party; (d) information that is independently developed or acquired by Recipient through persons who have not had, either directly or indirectly, access to or knowledge of such confidential information; or (e) any information that is disclosed with the prior written consent of the Disclosing Party.

43.0 PATENTS, COPYRIGHTS, AND TRADE SECRETS

Royalties and fees for patents, copyrights, trade secrets and other proprietary rights of third party covering materials, articles, apparatus, devices, equipment, or processes used in the Work shall be included in the Contract Price. The Contractor shall satisfy all demands that may be made at any time for such royalties or fees and it shall be liable for any infringement damages or claims for Contractor's patent, copyrights or trade secret infringements against Owner and its successors, and assigns. The Contractor shall, at its own cost and expense, defend all suits or proceedings that may be instituted against Owner for its use for alleged infringement of any patents, copyrights or trade secrets involved in the Work and, in case of an award of damages, the Contractor shall pay such award. If final payment is to be made while any suit or claim remains unsettled, the Contractor shall first obtain a surety bond in favor of Owner or other security acceptable to Owner as a condition of payment and the penal sum of the bond or other security will be at least 125% of the amount of the suit or the claim. Should use of the Work or any portion thereof be enjoined, Contractor shall, at Owner's election, and at its sole expense: (i) modify the Work so that it is no longer infringing without degrading form, fit or function; (ii) replace the infringing Work with equal or better non-infringing Work; or (iii) obtain a license for Owner to keep using the Work. Any assistance requested from Owner shall be supplied at Contractor's expense. The Contractor represents that it has full and unfettered rights to use all technology that it will use to perform the Work.

44.0 PUBLICITY

Contractor agrees to cooperate with Owner in maintaining good community relations. Owner will issue all public statements, press releases, and similar publicity concerning the Work, its progress, completion and characteristics. Contractor shall not make or assistant anyone to make any such statements, releases, photographs, or publicity without prior written approval of Owner.

45.0 NOT USED

46.0 ASSIGNMENTS

Contractor shall not assign this Contract wholly or in part, voluntarily, by operation of law, or otherwise without first obtaining the written consent of Owner. Any assignment of this Contract in violation of the foregoing shall be, at the option of Owner, void. Subject to the foregoing, the provisions of this Contract shall extend to the benefit of and be binding upon the successors and assigns of the parties hereto. Owner reserves the right at its sole option to assign this Contract to Owner's designated agent, or to Owner affiliates.

47.0 EMERGENCY MEDICAL SERVICES

Owner may furnish emergency medical treatment or related services to Contractor's employees in the case of job connected illness or injury occurring at the jobsite. In the event that such services are available, all such treatment or services, if any, are furnished on a Good Samaritan basis and not as a contractual obligation. In consideration of any such treatment or services, Contractor acknowledges that it assumes full and complete responsibility and liability for all injuries and damages to any of its employees arising out of or allegedly attributable in any way thereto. Nothing herein contained shall be construed as imposing any duty upon Owner to provide facilities necessary to furnish emergency medical treatment or related services to Contractor's employees or to make such facilities and/or services available to Contractor's employees.

48.0 OWNER'S DESIGNATED REPRESENTATIVE

As used in this Contract, Owner's Designated Representative means Mark Hickman, who is the liaison between Owner and Contractor during performance of the Work. No agreement with Owner's Designated Representative shall affect or modify any of the terms or obligations contained in this Contract, except as provided in Section 18, Changes. A copy of all correspondence concerning the Work shall be sent to Owner's Designated Representative. Owner reserves the right to change its Designated Representative at any time.

Contractor's representative, Mark Hickman is fully authorized to make commitments for and on behalf of Contractor until such times as the authorization is withdrawn or until satisfactory conclusion of this Contract.

Contractual notices to Owner shall be addressed to Owner's Home Office/Field Address set forth herein and marked Attn.:

Mark Hickman
Crystal River Unit 3 (SA2C)
15760 West Powerline Street
Crystal River, FL 34428-6708

Contractual notices to Contractor shall be addressed to Contractor's Home Office/Field Address set forth herein marked Attn.:

Mr. Gregg Mailen
EvapTech Inc.
8331 Nieman Road
Lenexa, KS 66214

- DOCUMENTATION, LIENS AND OFFSETS -

49.0 DOCUMENTATION AND RIGHT OF AUDIT

Contractor shall maintain accurate and detailed records, in accordance with generally accepted accounting principles consistently applied, of all expenditures or costs relating to any Work performed under this Contract and of any performance statistics relevant to this Contract. Contractor shall maintain these records for the life of the Contract plus five (5) years. If the Work is being performed other than on a fixed price basis and/or includes incentive provisions, Owner shall have the right to inspect, examine and make copies of any or all books, accounts, records and other writings of Contractor relating to the performance or cost of the Work. If the Work is being performed on a fixed-price basis only, Owner shall have the above-specified rights only upon termination or suspension of the Work. Such audit rights shall be extended to Owner or to any representative designated by Owner. Audits shall take place at times and locations mutually agreed upon by both parties, although Contractor must make the materials to be audited available within one (1) week of the request for them. Costs incurred in undertaking the audit will be borne by Owner but costs incurred by Contractor as a result of Owner's exercising its right to audit will be borne by Contractor.

50.0 LIENS

If requested by Owner and as a condition precedent to payment, Contractor and its subcontractors shall supply a release of lien related to the authorized Work, or affidavits that all bills for materials and labor have been paid and receipts showing the payment of these bills. Failure or refusal by Contractor to comply with such request shall excuse Owner from making any further payments to Contractor until Contractor does comply. Owner reserves the right to pay any outstanding obligations of Contractor for labor and materials used in the authorized Work by a check made payable jointly to Contractor and Contractor's vendors, subcontractors or employees. Any payment made in this manner shall apply as a payment to Subcontractor under this Contract. Owner may deduct from any payment any amounts owed to Owner by Contractor. In connection with Work to be performed by Contractor, Contractor agrees to indemnify and hold harmless Owner from any construction, materialmen's or laborer's liens or encumbrance arising out of the Work and to cause any such liens to be promptly discharged, at Contractor's sole cost, within five working days of getting notice of the lien.

51.0 RIGHT TO OFFSET

Owner, without waiver or limitation of any rights or remedies of Owner, shall be entitled from time to time to deduct from any amounts due or owing by Owner to Contractor in connection with this Contract (or any other contract with Owner), any and all amounts owed by Contractor to Owner in connection with this Contract.

52.0 NOT USED

- GENERAL -

53.0 NOT USED

54.0 SEVERABILITY

Any provision of this Contract which shall prove to be invalid, void, or illegal shall in no way affect, impair, or invalidate any other provision hereof, and such remaining provisions shall remain in full force and effect.

55.0 WAIVER

Owner's failure to insist on performance of any term, condition, or instruction, or to exercise any right or privilege included in this Contract, or its waiver of any breach, shall not thereafter waive any such term, condition, instruction, and/or any right or privilege.

No asserted waiver of any right or benefit by Owner shall be valid unless such waiver is in writing, signed by Owner, supported by consideration and specifies the extent and nature of the rights or benefits being waived.

56.0 GRATUITIES

Contractor, its employees, agents or representatives shall not offer or give to an officer, official or employee of Owner, gifts, entertainment, payments, loans or other gratuities to influence the award of a contract or obtain favorable treatment under a contract.

Violation of this Section may be deemed by Owner to be a material breach of this Contract and any other contract with Owner and subject all contracts with Contractor to Termination for Default, as well as any other remedies at law or in equity.

57.0 INTERPRETATION

Headings and titles of Sections, paragraphs or other subparts of this Contract are for convenience of reference only and shall not be considered in interpreting the text of this Contract. No provision in this Contract is to be interpreted for or against any party because that party or its counsel drafted such provision.

58.0 SURVIVAL

The provisions of this Contract which by their nature are intended to survive the termination, cancellation, completion or expiration of this Contract shall continue as valid and enforceable obligations of the parties notwithstanding any such termination, cancellation, completion or expiration.

59.0 IMMIGRATION LAW COMPLIANCE

Owner is committed to complying with all applicable immigration laws of the United States including the Immigration Reform and Control Act of 1986, as amended. This law requires that all employees hired since 1986 provide proof of identity and employment eligibility before they can work in the United States. It is the policy of the Owner to comply fully with this requirement, and to require compliance by all Contractors performing services at the Owner's worksites. Contractor shall not place any employee of Contractor at the Owner's worksite, nor shall Contractor permit any employee, nor any contractor or subcontractor, to perform any work on behalf of or for the benefit of the Owner, without first verifying and ensuring said employee's authorization to lawfully work in the United States.

To that end; Contractor acknowledges, agrees and warrants (a) that Contractor maintains and follows an established policy to verify the employment authorization of it's employees, and to ensure continued compliance for the duration of employment (b) that Contractor has verified the identity and employment eligibility of all employees, in compliance with applicable law, (c) that Contractor has established internal safeguards and reporting policies to encourage its employees to report any suspected violations of immigration policies or of immigration law promptly to Contractor's senior management, (d) that Contractor has implemented a policy to verify the validity of Social Security information provided by its employees at the time of hire by Contractor, (e) that Contractor is without knowledge of any fact that would render any employee, Contractor or subcontractor of the Contractor ineligible to legally work in the United States. Contractor further acknowledges, agrees, and warrants that Contractor (f) has complied, and shall at all times during the terms of this Contract comply, in all respects with the Immigration Reform and Control At of 1986, as amended, the Illegal Immigration Reform and Immigrant Responsibility Act of 1996, as amended, and all of the laws, rules and regulations relating thereto, (g) has properly maintained, and shall at all times during the term of this Contract properly maintain all records required by the United States Citizenship and Immigration Services (the "US CIS"), including, without limitation, the completion and maintenance of the Form I-9 for each of Contractor's employees, and (h) has responded, and shall at all times during terms of this Contract respond, in a timely fashion to any inspection requests related to such I-9 Forms. During the term of this Contract, Contractor shall, and shall cause its directors, officers, managers, agents, and employees to fully cooperate in all respects with any audit, inquiry, inspection or investigation that may be conducted by the US CIS of Contractor, or any of its employees. Contractor will also allow Owner to audit its process and inspect Contractor's records relating to this matter. Contractor shall, on a bi-annual basis during the terms of this Contract, conduct an audit of the I-9 Form for its employees and shall promptly correct any defects or deficiencies which are identified as a result of such audit.

60.0 CODE OF ETHICS

Contractor, Contractor's employees, and employees of Contractor's subcontractor(s) performing Work under this Contract shall comply with Owner's Code of Ethics. Owner will make the Code of Ethics available to Contractor in order for Contractor to provide a copy to any employee with (i) a presence for a single period of 15 calendar days or more upon property owned or leased by Owner (except right-of ways) or any of Owner's subsidiaries or affiliates and/or (ii) access to Owner's business critical infrastructure and/or (iii) security badge access to Owner facilities. Each such employee shall sign an Acknowledgment Form (Contained in Attachment D) in substantially the form set forth by Owner. Contractor shall retain the signed forms for Owner audit purposes for the term of the Contract plus one (1) year. The audit right provided herein shall not be restricted by any other audit provisions of the Contract. Contractor shall not be required to obtain signatures on Acknowledgement Forms for those employees assigned to Owner sites exclusively to provide storm support.

Contractor, Contractor's employees, and employees of Contractor's subcontractor(s) performing Work under this Contract are obligated to comply with all applicable laws and regulations and with all applicable health, safety and security rules, programs and procedures. The Owner Code of Ethics identifies principles concerning lawful and ethical conduct that must be followed by Contractor's employees in the performance of Work. The Code of Ethics also provides for an Alert Line reporting mechanism that enables the reporting of suspected violations of law and of the Code of Ethics as a part of Owner's program to prevent and detect violations of law and criminal or unethical conduct.

In order for Owner to confirm Contractor's compliance with the Code of Ethics requirements in this Contract, Contractor is required to complete the Code of Ethics Compliance Plan attached. This Plan identifies the points of contact within Contractor's organization and other information for Owner to use in verifying Contractor's compliance. Should any information on the Compliance Plan change during the term of the Contract, Contractor shall notify Owner's Designated Representative in writing within thirty (30) days of the change.

61.0 SECURITY

Contractor and Contractor's employees who perform Work at any Owner property shall comply with the security practices and procedures prescribed by Owner to cover that property.

Contractor shall advise its employees of these practices and procedures and secure their consent in a form satisfactory to Owner to abide by these procedures. Owner will make a copy of these practices and procedures available to Contractor upon request.

62.0 FITNESS-FOR-DUTY POLICY

Contractor acknowledges its awareness of Owner's contract personnel Fitness-For-Duty Program (FFDP) Drug and Alcohol Abuse Policy, which is as follows:

The use, possession, or sale of narcotics, hallucinogens, depressants, stimulants, marijuana, or other controlled substances on Owner Property or while in pursuit of Owner business is prohibited. (This does not apply to medication prescribed by a licensed physician and taken in accordance with such prescription.) Unauthorized consumption of alcohol on Owner Property is also prohibited. The use of the above substances or alcohol on or away from Owner Property which adversely affects the employee's job performance, or may reflect unfavorably on public or governmental confidence in the manner in which Owner carries out its responsibilities, as determined by Owner, is also prohibited.

The term "Owner Property" includes any property or facility owned, leased, or under control of Progress Energy, Inc. or any of its subsidiaries, wherever located, including land, buildings, structures, installations, boats, planes, helicopters, and other vehicles.

1. Contractor shall advise its employees and the employees of any subcontractors and assignees [hereinafter referred to as "Contractor's employee(s)] of the following:

   a. Owner's contract personnel Fitness-For-Duty Program (FFDP) Drug and Alcohol Abuse Policy as set forth above.

   b. That by entry onto Owner Property, Contractor's employee consents to testing for the presence of drugs or alcohol, search or inspection of him or his property, including his vehicle and closed containers within the vehicle, at any time while on the Property.

   c. That any of Contractor's employees found in violation of the policy, or who refuses to permit a search, inspection or testing as specified above, may be removed and barred from Owner Property at the sole discretion of Owner.

2. Contractor shall also institute control measures to prevent the use, possession, or sale of drugs, controlled substances, or the unauthorized consumption of alcohol on Owner Property or while engaged in Work for Owner.

63.0 FEDERAL SUBCONTRACTING REQUIREMENTS

The provisions of the following Laws, Executive Orders, and any rules and regulations issued thereunder, are incorporated herein by reference as part of this Contract.

- Provisions of the Utilization of Small Business Concerns clause set forth at Section 52.219-8 of the Federal Acquisition Regulations, Title 48 of the Code of Federal Regulations

- Provisions of the Small Business Subcontracting Plan clause set forth at Section 52.219-9 of the Federal Acquisition Regulations, Title 48 of the Code of Federal Regulations.

1. The Contractor agrees to fully comply with such provisions and any amendments thereof. In addition, all subcontracts and agreements that the Contractor enters into to accomplish the Work under the terms of this Contract shall obligate such subcontractors to comply with such provisions.

2. Compliance with the above provisions involve the development of a subcontracting plan, as prescribed in 19.704 of the Federal Acquisition Regulations, herein incorporated by reference. The attached Contractor Diversity and Business Development Subcontracting Report shall be used to report awards to small business concerns under the subcontracting plan, (Attachment E).

64.0 WORKPLACE VIOLENCE PREVENTION

Owner strives to provide a workplace for a worker that is free from physical attack, threats of violence and menacing or harassing behaviors.

Owner will not tolerate any unwanted or hostile physical contact, including physical attack, threat of violence, harassment, or damage of property by or against any worker including Owner employees.

Any worker who experiences, witnesses, or has knowledge of acts, conduct, behavior, or communication (threat) that may constitute or may lead to a workplace violence event should immediately report the incident to any of the following:

- Contractor Supervisor or Owner supervisor or manager, AND
- Corporate Security 1-888-275-4357 or
- The Ethics Line at 1-866-8Ethics (1-866-838-4427)

65.0 MUTUAL PREPARATION

Each party to this agreement and its counsel have participated in the creation of this agreement. The normal rule of construction to the effect that ambiguities are to be resolved against the drafting party shall not be employed in the interpretation of this agreement or of any amendments or exhibits to this agreement.

66.0 BACKGROUND INVESTIGATION AND DRUG SCREEN

NOTE: The requirements of this Section do not apply to nuclear protected/vital area access. If Contractor requires access to nuclear protected/vital areas, Contractor shall obtain those requirements from Owner's Designated Representative and comply with those requirements when obtaining access to nuclear protected/vital access areas.

In order for Owner to confirm Contractor's compliance with the Background Investigation/Drug Screen requirements in this Contract, Contractor is required to complete the Background Investigation/Drug Screen Compliance Plan (Attachment A). This Plan identifies the points of contact within Contractor's organization and other information for Owner to use in verifying Contractor's compliance. Should any information on the Compliance Plan change during the term of the Contract, Contractor shall notify Owner's Designated Representative in writing within thirty (30) days of the change.

Contractor shall conduct a Background Investigation ("BI") and pre-assignment Drug Screen ("DS") as described below for all Contractor's employees and/or Contractor's subcontractor employees where the scope of work to be performed will require: (i) a presence for a single period of 15 calendar days or more upon property owned or leased by Owner (except right-of ways) or any of Owner's subsidiaries or affiliates and/or (ii) access to Owner's business critical infrastructure and/or (iii) security badge access to Owner facilities. In addition, BI/DS requirements may be applied to other personnel at the sole discretion of Owner's Designated Representative. Owner shall reimburse Contractor in accordance with Paragraph E of this Section for each Contractor employee and subcontractor employee for whom an approved provider performs full or updated BIs and DSs, unless Work is performed on a firm fixed price basis. Owner shall not be obligated to reimburse Contractor for any BI or DS expense for any Contractor employee or subcontractor employee who fails to meet the minimum acceptable qualifications. The BIs and DSs must be performed by service providers approved by Owner as acceptable to conduct BIs and DSs (the "Approved BI and DS Providers"). Paragraph E of this Section lists the Approved BI and DS Providers.

Contractor shall obtain a release from each of its employees and subcontractor employees that will perform Work under the terms of this Contract that allows Owner to access the BI and DS records from the Approved BI and DS Provider's web enabled access systems or through other methods agreeable to Owner. Owner will access these records only for the purpose of conducting periodic audits to ensure compliance with the conditions herein, and for the purpose of audit required by a governmental agency. In instances in which an employee or any subcontractor employee of Contractor is granted access to a facility or property that is covered within the scope of the North American Electric Reliability Corporation Critical Infrastructure Protection (NERC CIP) regulations, 18 CFR 39, or the Chemical Facility Antiterrorism Act (CFATS) regulations, 6 CFR 27, Contractor agrees to permit Owner to obtain and maintain a copy of the BI and DS of each Contractor employee or subcontractor employee in order for Owner to demonstrate access eligibility and compliance with the NERC CIP and CFATS regulations.

In the event Contractor uses a BI and/or DS provider or process that is not pre-approved by Owner, Contractor is required to submit its BI and DS program to Owner for review and approval. Contractor agrees to permit Owner to obtain copies of the BI result information when needed for regulatory reasons, and to audit the BI result information as necessary to establish Contract compliance.

Contractor agrees to maintain BI records for a minimum of seven (7) years after the Work is completed.

Contractor is solely responsible for ensuring that Contractor's employees and any subcontractor employees assigned to the Work meet or exceed the requirements of this Section. Contractor must have all BIs and DSs completed prior to the start of Work. In the case of emergencies, Contractor may be permitted to start Work while the BIs or DSs are being conducted. (If an emergent need requires delay in processing, Owner approval is required, and all BIs and DSs must be completed within 10 working days of the start date).

A. Responsibilities

Contractor shall be responsible to:

1. Comply with the legal requirements of the Immigration Reform and Control Act of 1986, including, but not limited to, verifying its employees' and ensuring its subcontractors verify their employees' eligibility for U.S. employment through the completion of an I-9 form for each employee or subcontractor employee. Documentation of I-9 form completion will be maintained by the Contractor and made available to Owner upon request. Contractor is the employer and makes decisions regarding assignments.

2. Initiate and ensure the completion of the appropriate BIs. Contractor's employees and Contractor's subcontractor employees should be required to complete a background questionnaire or employment application which includes additional names used by applicant, history of residences and criminal history. Contractor is the employer and makes decisions regarding assignments based on these guidelines.

3. Notify its employees and any subcontractor employees of the terms and conditions of the BI and DS and requirements of this Contract.

4. Furnish Owner with any Contractor employees and subcontractor employees who meet or exceed the requirements of the BI and DS and the terms and conditions of the Contract.

5. Obtain written permission for the release to Owner of its employees' and any subcontractor employees' personal history information and information contained in the BI report and DS.

6. Require its employees and subcontractors to report any arrest and evaluate under the Rejection Criteria to determine if Contractor's employee or any subcontractor employee meets Owner's criteria for rejection. (All Contractor employees and any of its subcontractor employees who meet the Rejection Criteria must be removed from Owner's Work immediately.)

7. Abide by the Fair Credit Reporting Act (FCRA) requirements and all other applicable state and federal laws regarding BIs and DSs, and consent to release information.

B. Types and Components of Background Investigation

1. Full Background Investigation

a. Social Security Number/Name/Address Validation

Contractor shall verify the Social Security Number (SSN), name, date of birth and/or addresses of its employees, and ensure its subcontractors verify the same of their employees, from sources such as an SSN trace report available through credit databases. Contractor agrees to perform, and ensure its subcontractors perform, additional criminal history checks for names and addresses that appear on the SSN report within the past seven (7) years and cannot be attributed to a spouse's surname or typographical error. Contractor, and its subcontractors, shall resolve any discrepancies discovered, including multiple SSNs that do not appear to be typographical in nature, fraud alerts, and any address associated with Correctional, Hospital or Clinical Institutions. Contractor shall verify its employees', and ensure its subcontractors verify its employees', SSNs through the Social Security Administration.

b. Criminal Record

Prior to Contractor's employee or subcontractor employee performing Work, Contractor shall conduct a criminal history record check covering the previous seven years, or to age 18, in each state/locality where Contractor's employee has resided, including addresses within the past seven years identified on the SSN Trace Report, or where Contractor's employee disclosed criminal history on the background questionnaire. Contractor shall take action to ensure its subcontractors conduct the same criminal history record check and comply with the requirements listed in this subsection for each of its employees.

Record checks should be conducted by contacting the appropriate agency of record such as state law enforcement agency, state criminal record repositories (normally statewide repositories should only be used for states such as New York and North Carolina, unless otherwise approved), local law enforcement agencies, state and local courts. Contractor shall ensure record repositories hold complete criminal history information (pending cases, misdemeanor records, and felony records, etc).

Reported criminal records should include specific offense information, court and jurisdiction and disposition of charge.

c. Terrorist Watch List Search (Patriot Act)

Contractor shall conduct a Terrorist Watch List search through the U. S Office of Foreign Asset Control on Contractor's employees and subcontractors employees intended to perform Work. The search shall include a check of whether the employee or subcontractor employee is a Designated National or Blocked Person, as defined by the U. S Office of Foreign Asset Control.

d. Drug Screen

Contractor shall conduct a DS as defined in this Section.

2. Updated Background Investigation

An updated BI is acceptable for Contractor's re-hired employees or subcontractors' employees if the employee or subcontractor employee previously had a full BI and DS completed that meets Owner's criteria described in this Section and it was completed by the current Contractor within the past three years of current effective Work start date. The following components shall be checked:

- Criminal history checks in the county or counties where Contractor's employee or subcontractor employee has resided, including addresses on the SSN Trace Report since the last seven year check was performed.
- Terrorist Watch List search
- DS

C. Rejection Criteria to Disqualify Candidates for Assignment

The decision by Contractor to disqualify an employee or subcontractor employee for assignment shall be based upon consideration of all relevant information, favorable and unfavorable, as to whether the assignment would be clearly consistent with the necessity to maintain an environment conducive to a safe work place.

To assist in making appropriate determinations, this matrix identifies several types of adverse information. These are not all-inclusive, but contain many of the factors, which may raise legitimate questions to a Contractor's employee's or subcontractor employee's eligibility for assignment. Contractor is the employer and makes decisions regarding assignments based on these general guidelines.

1. Criminal Charges

a. Criminal Charges Pending

"Pending" is defined as awaiting formal review by the court to determine the disposition of the arrest. All pending charges will be evaluated on a case by case basis; however pending charges which may meet Owner's criteria for disqualification if convicted will normally preclude an acceptable recommendation.

Charges which result in a disposition of adjudication withheld, nolle pross, pre-trial intervention, prayer for judgment continued or are otherwise unadjudicated shall be evaluated on a case by case basis. This evaluation shall focus on the status of the charge, and the behavior or incident which resulted in the charge being made, and the effect on an applicant's trustworthiness and reliability.

b. Felony Convictions

CRITERIA FOR REJECTION	ACTIONS TO BE CONSIDERED
Any felony conviction with in the last five years	Not eligible for assignment for five years from the date of conviction.
Persons currently on active probation/parole or a work furlough program for a felony conviction or participating in court diversion program for charges which would meet rejection criteria. (Ex. Pre-trial intervention and deferred prosecution).	Not eligible for assignment until completion of probation or parole or court diversion program. Eligibility must also comply with criteria above. (As if convicted)
Failure to fulfill a court order (i.e. failure to appear) for any felony conviction.	Not eligible for assignment until disposition of court order is completed.

c. Misdemeanor Convictions

CRITERIA FOR REJECTION	ACTIONS TO BE CONSIDERED
Any misdemeanor conviction within the last five years involving illegal drugs (includes individuals currently serving a court-ordered diversion program)	Not eligible for assignment for five years from date of last conviction.

Any misdemeanor conviction within the last year involving violence or theft.	Not eligible for assignment for one year from the date of conviction.
Three or more misdemeanor convictions involving alcohol, violence or theft within the last five years. For example, convictions in 11/2005, and 11/2006 and 6/2007 not eligible until 11/2010	Not eligible for assignment for five years from the date of earliest conviction.
Persons on active probation/parole or a work furlough program for a misdemeanor conviction or participating in court diversion program for charges which would meet rejection criteria. (Ex. Pre-trial intervention and deferred prosecution).	Not eligible for assignment until completion of probation or parole or court diversion program. Eligibility must also comply with criteria above. (As if convicted)
Multiple misdemeanor convictions; including, but not limited to acts of violence, alcohol, and theft that demonstrate a pattern of continued disregard for the laws of the land and adversely reflects on the person's reliability and trustworthiness.	Contractor shall exercise reasonable discretion to determine appropriate action on a case by case basis.
Failure to fulfill a court order (i.e. failure to appear) for any misdemeanor conviction	Assignment may not be recommended based on the severity of the court order.

d. Other

CRITERIA FOR REJECTION	ACTIONS TO BE CONSIDERED
One drug test failure	Not eligible for assignment for 5 years.
Evidence or admission of use, possession or sale of illegal substances	Not eligible for assignment for 5 years from the most recent occurrence.
The refusal to participate in drug testing	Not eligible for assignment.
Attempted to subvert the testing process, or has shown in anyway to have altered a specimen provided for testing	Not eligible for assignment for 5 years.
Any other information that would adversely reflect upon the reliability and trustworthiness of the person as it relates to their assignment to Owner	Not eligible for assignment – eligible to reapply determined on a case by case basis.
Prior termination due to a Progress Energy Code of Ethics Violation	Not eligible for assignment.
Information regarding denial at any of Owner's nuclear facilities.	Employment may not be recommended based on the reason for denial.
Social Security Number not verified by Social Security Administration	Not eligible for assignment until verification of Social Security Number is validated.

D. Drug Screen

All of Contractor's employees and subcontractors' employees who will require a BI will also be required to have a DS. Contractor must have all DSs completed prior to the start of Work. In the case of emergencies, Contractor may be permitted to start Work while the DSs are being conducted. (All DSs must be completed within 10 working days of starting work.)

A certified Health and Human Services Laboratory must perform all DSs. Only Contractor employees and subcontractor employees whose test result is determined to be negative are eligible to work on Owner controlled property. In addition, Contractor employees and subcontractor employees who refuse to participate in DSs, attempt to subvert the DS testing process, or are shown in any way to have altered a specimen provided for any DS are not eligible to work under this Contract.

Owner shall not be obligated to reimburse Contractor for any DS expense for Contractor employees or subcontractor employees who fail to meet the minimum acceptable qualifications.

The screening for the substances below and the testing levels generally follow the Department of Transportation Guidelines. Laboratories that use lower cut off levels for drugs or Metabolite than those listed below are acceptable by Owner.

1. Drug Screen Cut Off Concentrations for Screening and Confirmation Levels

Type of Drug or Metabolite	Initial Test	(f) *(e)* Confirmation Test
Marijuana Metabolites	50	15
Cocaine Metabolites (Benzoylecgonine)	300	150
Phencyclidine (PCP)	25	25
Amphetamines	1000	
Amphetamine		500
Methamphetamine		500 (specimen must also contain amphetamine at a concentration of greater than or equal to 200 ng/ml.)
Opiate metabolites	2000	
Codeine		2000
Morphine		2000
6-monacetylmorphine (6-MAM)		10 (Test for 6-MAM in the specimen. Conduct this test only when specimen contains morphine at a concentration greater than or equal to 2000 ng/ml.)

2. Specimen Collection

The specimen must be collected by trained and qualified collectors and collected under conditions that protect the integrity of the specimen. Laboratory patient service centers and Doctor's Urgent Care are suggested for collection purposes.

E. Approved Background Investigation and Drug Screening Providers

1. Sterling Testing Systems
   Attn: Lance Zacker
   Regional Director of Sales

   Phone: 212-812-1045

Fax: 646-435-2273
E-Mail: Lzacker@sterlingtesting.com
www.sterlingtesting.com

2. A-Check America, Inc.
   Attn: Alanna Flores

   Phone: 877-345-2021 ext. 3085
   Fax: 951-750-1667
   E-Mail: aflores@acheckamerica.com
   progressenergy@ acheckamerica.com
   www.acheckamerica.com

BI/DS Pricing:
The providers listed above have pre-established pricing with Owner for performing a BI/DS. Owner reimbursements will be at the pre-established rates. If Contractor chooses to use a provider not listed above, reimbursements will be capped by the rates charged by the above providers. The cost for performing a BI/DS is currently capped at $55.00. This amount is subject to increase only if the pre-established rates increase for the above providers. Criminal Searches within the 7 year time frame required outside of the United States will be reimbursed as pass-through expenses at reasonable and customary costs.

67.0 REGULATORY COMPLIANCE

The Contractor shall comply with the following regulatory compliance issues:

Contractor is to notify the Owner's Designated Representative or his designee on a weekly basis as to the number of employees per shift reporting to the Site.

Owner will be responsible for all written and telephone notifications and communications with all regulatory agencies, except for any such notifications which may be the sole responsibility of the Contractor as required by law.

68.0 LAWS AND PROJECT RULES

A. General

Contractor and its subcontractors, if any, shall observe and abide by all applicable laws, federal, state and local, and the rules and regulations of any lawful regulatory body acting thereunder in connection with the Work. Without limiting the foregoing, Contractor agrees to comply with applicable provisions of the Americans with Disabilities Act, Fair Labor Standards Act of 1938, Executive Order No. 11246, the Rehabilitation Act of 1973, the Vietnam Veterans Readjustment Act of 1974, as amended, and their respective implementing regulations, which are made a part hereof as if set out herein. Contractor warrants that it will meet the legal requirements of the Immigration Reform and Control Act of 1986, including, but not limited to, verifying workers' eligibility for U.S. employment through the completion of an I-9 form. Contractor and its subcontractors, if any, shall also comply with all applicable Owner health, safety and security rules, programs or procedures.

Contractor shall indemnify and hold Owner (including its parent, subsidiary and affiliate companies) and its plant co-owners harmless with respect to any claims, expenses (including attorney's fees), liability or damages arising out of Contractor's failure to comply with any applicable laws, rules, or regulations, or any Owner rules, programs, or procedures.

Work performed and materials and equipment provided by Contractor shall conform to and comply with all the applicable site safety programs and procedures, federal, state, and municipal laws, rules, and regulations concerning occupational health and safety, including, but not limited to, the Occupational Safety and Health act of 1970 and the regulations and standards issued thereunder (hereinafter "OSHA requirements"). Contractor warrants that any work performed in a location partially or entirely under Contractor's control shall be performed in accordance with "OSHA Requirements". Contractor further warrants that all materials and equipment furnished by Contractor shall conform to and comply all applicable provisions of "OSHA requirements" and the regulations and standards issued thereunder, specifically those (designed to accept a lockout device, machine guards in place, etc.) Contractor shall require these warranties of adherence to "OSHA requirements" from each subcontractor and Contractor it employs. Contractor shall indemnify and hold harmless Owner (including its parent, subsidiary and affiliate companies) from all damages suffered by Owner (including its parent, subsidiary and affiliate companies) (including damages to third parties) as a result if the failure of Contractor or any of its subcontractors or Contractors to comply with "OSHA requirements" and for the failure of any of the materials or equipment furnished to so comply.

B. Employment Taxes and Contributions

Contractor assumes exclusive liability for all contributions, taxes or payments required to be made under the applicable federal and state Unemployment Compensation Act, Social Security Acts and all amendments, and by all other current or future acts, federal or state, requiring payment by the Contractor on account of the person hired, employed or paid by Contractor for Work performed under this Contract. When Work is to be performed in South Carolina, Contractor shall submit to Owner, prior to commencement of Work, a properly completed State of South Carolina, Department of Revenue, Nonresident Taxpayer Registration Affidavit Income Tax Withholding form which will be included as an attachment.

C. Drawings and Specifications

It is the intent of Owner to have all drawings and specifications for the Work comply with all applicable statutes, regulations, and ordinances. If Contractor discovers any discrepancy or conflict between the drawings and specifications and applicable legal requirements, Contractor shall immediately report the discrepancy in writing to Owner's Designated Representative.

D. General Contractor's License Requirements

The Contractor shall comply with the applicable requirements of the governing state to regulate the practice of general, mechanical, and electrical contracting.

E. Environmental Provisions

1. Compliance with Environmental Laws

    a. In performing its obligations and other activities pursuant to this Agreement, Contractor shall comply with all Environmental Laws.

    b. If while performing Work Contractor encounters ACM and/or lead, Contractor immediately shall notify the Designated Representative. Contractor shall not Manage such ACM and/or lead without Owner's prior approval. Contractors shall perform any such work in accordance with the acceptable industry standards and practices.

c. Contractor may obtain from the Designated Representative any records and other information which the Designated Representative deems relevant to Contractor's compliance with Environmental Laws. Owner does not warrant the accuracy or completeness of such records and information, and Contractor shall determine independently how to conform its activities to the requirements of Environmental Laws.

2. Regulated Substances and Hazardous Chemicals

a. For purposes only of this Subsection 2., Owner Property means property Owner owns, leases and/or operates.

b. Prior to bringing any Regulated Substance onto Owner Property Contractor shall deliver to the Designated Representative: (1) notice of the Regulated Substance's identity and intended use, (2) notice of the length of time the Regulated Substance will be used on Owner Property and (3) a description of any wastes that will be generated as a result of using the Regulated Substance.

c. Prior to bringing onto Owner Property any Regulated Substance, Contractor shall deliver to Owner a description of the potential for Owner employee exposure to the hazardous chemical, the hazardous chemical's brand name (including generic name and chemical abstract number [CAS#]), container volume or weight, number of containers, container pressure and temperature, physical state, storage location, estimated annual usage, manufacturer and material safety data sheet.

d. Contractor shall deliver to Owner for Management any hazardous waste which Contractor generates on Owner Property. Contractor shall not remove such hazardous waste from Owner Property.

e. Upon completion of the Work, Contractor shall remove all of Contractor's unused chemicals from Owner Property.

3. Releases

a. Contractor shall not Release any Regulated Substance on Owner Property, or on any roadways leading to or from Owner Property.

b. In the event Contractor Releases any material or substance on Owner Property, Contractor immediately shall notify the Designated Representative and remediate the Release pursuant to all applicable Environmental Laws and to Owner's direction and reasonable satisfaction. Owner's costs in supervising, directing, inspecting and/or assisting Contractor to respond to the Release shall be subject to Indemnification under Subsection 4. hereof.

c. If following a Release Contractor fails to comply with the terms of Subsection 3.b., Owner may in its discretion remediate the Release and otherwise perform Contractor's obligations. Owner's costs in performing Contractor's remedial activities shall be subject to Indemnification under Subsection (4) hereof.

4. Environmental Indemnity

a. Contractor shall Indemnify Owner (including its parent, subsidiary and affiliate companies) from any Claim or loss in property value arising in any way from Contractor's Management of any Regulated Substance or Contractor's failure to comply with the terms of this Agreement.

5. Environmental Audits

Owner shall have the right to conduct an on-site environmental review of any of the Contractor's or its subcontractor's or Contractor's facilities at any time to verify compliance with federal, state and local statutes, regulations and ordinances. Contractor shall ensure that Owner shall have the right to conduct on-site environmental audits of any subcontractor's facilities to verify compliance with all federal, state and local statutes.

6. Definitions

The definitions below only are applicable to this Section.

a. ACM or Asbestos-Containing Material means (a) friable asbestos material, (b) Category I nonfriable ACM (as defined in 40 C.F.R. §61 (Subpart M)) that has become friable, (c) Category I nonfriable ACM that will be or has been subjected to sanding, grinding, cutting or abrading or (d) Category II nonfriable ACM (as defined in Subpart M) that has a high probability of becoming or has become crumbled, pulverized or reduced to powder by the forces expected to act on the material in the course of demolition or renovation operations.

69.0 <u>REPORTS</u>

Whenever requested by Owner, Contractor shall furnish within a reasonable period of time and in the manner directed, written reports about the authorized Work. Owner may require these reports to show the progress or status of the Work of any other matter pertaining to it.

70.0 <u>AMENDMENT OF CONTRACT</u>

The terms and conditions of this Contractor may be changed or modified only by execution of a written Contract Amendment executed by both parties. Oral Changes to this Contract or to any Amendment issued under it shall have no effect.

71.0 <u>GOVERNING LAW</u>

This Contract shall be governed by the laws of the State of North Carolina, except that the North Carolina conflict-of-law provisions shall not be invoked in order to apply the laws of any other state or jurisdiction. Owner and Contractor expressly waive their rights to a trial by jury in any action brought hereunder.

72.0 LIMITATION OF LIABILITY

Neither Owner, nor Contractor shall be liable to each other for any consequential damages arising out of any breach of Contract. Excluding any claims against Owner and Owner's officers, employees, agents (including Owner's parent, subsidiary and affiliate companies and their officers, employees, agents) that are covered by any indemnity obligation of Contractor, and excluding any claims against Owner and Owner's officers, employees, agents (including Owner's parent, subsidiary and affiliate companies and their officers, employees, agents) for infringement of intellectual property rights (including patents, copyrights, trade secrets, trademarks or other third party intellectual property rights), Contractor's total liability to Owner under this Contract shall not exceed the total value of the Work to be performed by Contractor under this Contract.

73.0 TRANSPORTATION WORKERS IDENTIFICATION CREDENTIAL

Owner's Bayboro, Bartow and Crystal River Complex are federally regulated facilities under 33 CFR 105 of the Maritime Transportation Security Act of 2002. Within these facilities there are secure areas that require any person entering the secure areas to be a Transportation Workers Identification Credential (TWIC) holder for unescorted access. The areas affected by this regulation include:

Bayboro: Fuel tank farm and fuel port terminal.
Bartow: North and South fuel port terminals, T1 and T2 fuel tank farm, # 2 fuel tank farm, and Gulfstream meter station.
Crystal River: South Coal Yard and South port terminal.

Contractor is required to supply personnel who have been processed through the TWIC and hold the credential prior to assignment or arrange for escort with Owner.

74.0 PASSPORT DATA LOADING

Contractor shall provide upon final as-built delivery the information as indicated in the PassPort Data Load Template for all drawings and Vendor manuals, see Attachment G.

The parties execute this Contract by their signature or the signature of their authorized agents.

PROGRESS ENERGY FLORIDA, INC.

BY: Mark A. Mueller

NAME (printed): Mark A. Muller

TITLE: **President – EvapTech Inc.**

DATE: 5-01-09

BY:

Tony Owen

Manager – NGG Major Projects
As agent for
Progress Energy Florida

DATE: 4/28/2009

Indicate your Social Security Number (SS#) OR your Employer Identification Number (EIN). This number shall correspond with the Consultant name indicated above and shall be the same TIN under which you report income. COMPLETE ONLY ONE.

EIN 20-2114254	SS# ___-__-___

The Internal Revenue Service (IRS) requires us to obtain certain information from you to meet IRS Form 1099 reporting and filing requirements.

If you do not provide your correct Taxpayer Identification Number (TIN), your payments may be subject to 20% backup withholding.

Under penalties of perjury, I certify that the TIN shown above is correct for the consultant named.

JOHN FOERSTER CONTROLLER
(Contractor to fill in name and title)

is appointed as the person to whom all official correspondence to Consultant concerning this Contract should be directed.

BACKGROUND INVESTIGATION/DRUG SCREEN COMPLIANCE PLAN

CONTRACT # 433059

Company Name: ____

Person providing this information: ____

Title: ____

Phone number: __________________ Email: ____

1. Which of the two preferred vendors will you use to perform your background investigations?
___ Sterling (Preferred Vendor) ___ A Check America Inc. (Preferred Vendor)

If leveraging another company, you will be required to submit your program to Owner for approval (see Preferred Vendor Exception sheet for required criteria and instructions).

___ Other: ___________________________________ **(Owner approval required)**

2. Who has overall responsibility for ensuring the completion of the background investigations and drug screens within your company?

Name: ____
Title: ____
Phone Number: _______________________ Email: ______________________________

3. Who within your company reviews findings of background investigation and drug screen results to confirm that a worker satisfies Owner's criteria, as defined in the Contract?
Name: ____
Title: ____
Phone Number: _______________________ Email: ______________________________

4. Describe the retention plan for the background investigation/analysis data and drug screen results.

Format Stored: ___ Hard Copy ___ Scanned PDF ___ Other (explain) ____________________
Location Stored: ____

5. Describe the review/audit process for this data when Owner requests to review.

Point of contact: ___________________________________ Phone Number: _______________

Email: ____

If using Sterling and/or A Check America, Inc. . . . Will you provide electronic access to Owner to through Sterling and/or A Check America, Inc.'s website when background/drug screen data is needed as defined in the Contract?

___ Yes ___No If no, or not using an Owner recommended vendor, will records be provided by:

___ Fax ___ Hardcopy via mail ___ Other (explain) ________________________________

BACKGROUND INVESTIGATION/DRUG SCREEN COMPLIANCE PLAN: PREFERRED VENDOR EXCEPTION

In order for Owner to approve the use of an alternate background/drug screen vendor, your company's Background Investigation/Drug Screen Plan must be submitted to Owner for review and approval, and must include ALL of the following criteria:

- A mechanism for obtaining information, including past criminal history from the employee (i.e.
  employment application)
- A process for verification of employee Social Security Numbers
- Program must address who is responsible for the review of documentation from the BI/DS to determine if requirements for access as described in the background and drug testing criteria are met
- Steps which the company takes if an arrest/conviction is discovered or reported after the BI is complete
- Mechanisms used to obtain permission from the employee for PE personnel to access their records for review and audit
- Record Retention Program
- I9 Verification Process
- Drug Screening Program shall include:
  - Number of drugs tested and type of drug
  - Confirmation Levels
  - Specimen Collection Process
  - Process used for evaluating Positive test results
- Please provide a Sample Background Investigation and Drug Screen result, received from the background vendor, with the following elements included:
  - SSN Trace
  - 7 Year Criminal Records Search
  - OFAC – Terrorist Watch List Search
  - Drug Screen Result

This information should be submitted to Owner with your signed Contract if an exception is taken to using the preferred background/drug screen vendors. Failure to submit your company's Background Investigation/Drug Screen Plan will result in a delay of the issuing of your Contract.

NOT USED

CODE OF ETHICS COMPLIANCE PLAN

CONTRACT # ______________

Company Name: ____

Person providing this information: ______________________________

Title: ____

Phone number: _________________ Email: ___________________________

1. Owner requires Contractor adherence to conduct/ethics compliance standards for its workers. Owner offers its own Code of Ethics standards for any company desiring to use them; however, if exception is taken, Contractor is required to demonstrate that their workers are covered by Contractor's equivalent program. Please indicate the program which applies to this Contract?

___ Owner's Code of Ethics
___ Contractor's internal program standards (Owner review and approval required. Please attach information about your Code of Conduct/Ethics, acknowledgment and documentation procedures.)

2. Who within your company has overall responsibility for worker acknowledgement forms related to the Code of Conduct/Ethics?
Name: ____

Title: ____

Phone Number: ____________________ Email: ___________________________

3. What is your process for ensuring each of your employees provides written acknowledgment of his/her awareness of code of Conduct/Ethics standards and expectations prior to performing work for Owner?

____

____

4. Describe the retention plan for the Code of Conduct/Ethics acknowledgement forms once signed by your employees.
Format Stored: ___ Hard Copy ___ Scanned PDF ___ Other (explain) __________________

Location Stored: ____

5. Describe the review/audit process for the signed acknowledgement forms when Owner requests to review.
Point of contact: __________________________ Phone Number: ___________________

Email: ____

Location where forms can be reviewed: ______________________________________

Notification interval required for review (how many hours/days): ______________________

Procedure for getting access: ____

Contract Employee
Code of Ethics Acknowledgment Form

Please go to the following website to review the Progress Energy Code of Ethics prior to signing this Acknowledgment Form. Hard copies are available upon request.

http://www.progress-energy.com/investors/corpgov/codeofethics.asp

I have read the Progress Energy Code of Ethics. I understand that the principles stated in the Code of Ethics represent those of Progress Energy as they relate to the work I perform as an independent contractor (or as an employee of an independent contractor of Progress Energy), and that violating those principles, or the legal and regulatory requirements applicable to my work may result in disciplinary action by my employer. I agree to abide by and support the legal and regulatory requirements applicable to my work. I understand that if I have questions concerning appropriate ethics or relevant legal and regulatory requirements, I should consult with my supervisor.

____
Signature of Contract Employee

____
Name of Contract Employee

____
Date

____
Social Security Number

____
Contractor Organization

SUPPLIER DIVERSITY & BUSINESS DEVELOPMENT SUBCONTRACTING REPORT

REPORTING METHOD AND DEFINITIONS

REPORTING METHOD

Please complete the attached form, Supplier Diversity & Business Development Subcontracting Report, to record your awards with small business concerns that are directly related to fulfilling a specific Progress Energy contract. Provide contract number, dollar amount and the per cent of award to small business concerns. Quarterly and cumulative annual period reporting is required.

REPORTING TIME SCHEDULE

Please provide the information requested for subcontracting quarterly report by the 15th of the month following the end of the quarter that you are reporting. The completed form may be faxed to Progress Energy Service Co., LLC, Manager-Supplier Diversity & Business Development, (919) 546-6750 or mailed to Progress Energy Service Co., LLC, Manager-Supplier Diversity & Business Development, P.O. Box 1551, Raleigh, NC 27602.

SMALL BUSINESS CONCERNS (SBC) DEFINITIONS*

- **Small Disadvantaged Business Concern** (SDB) - A business at least 51 percent of which is owned (or, in the case of publicly owned businesses, at least 51 percent of the stock of which is owned) by one or more minority individuals or other individuals found to be disadvantaged as established by the Small Business Administration and whose management and daily operations are controlled by individuals including the following minority classes (for clarification, refer to FAR 52.219-8).

Minority Type:

- African American Male	- Hispanic American Male	- Asian-Pacific American Male
- African American Female	- Hispanic American Female	- Asian –Pacific American Female
- Native American Male	- Asian-Indian American Male	
- Native American Female	- Asian-Indian American Female	

Native American	Includes American Indians, Eskimos, Aleuts and Native Hawaiians
Asian Pacific	Includes U.S. citizens where origins are from Japan, China, Philippines, Vietnam, Korea, Samoa, Guam, U.S. Territories of Pacific, Laos, Cambodia and Taiwan
Asian Indian	Includes U.S. citizens where origins are from India, Pakistan and Bangladesh

- **Women-Owned Business Concern** (WOSB) – A business that is at least 51 percent owned by a non-minority woman and who controls the daily management (for clarification, refer to FAR 52.219-8).

- **Hubzone Small Business Concern** (HBZ) – A business that appears on the list of qualified hubzone small business concerns maintained by the Small Business Administration.

- **Veteran-owned Small Business Concern** (VOSB)- A business at least 51 percent of which is owned (or, in the case of publicly owned businesses, at least 51 percent of the stock of which is owned) by one or more veterans and whose management and daily operations are controlled by one or more veterans.

- **Small Business Concern** (SB)- A business independently owned and operated that is not dominant in its field and that meets Small Business Administration standards as to the number of employees, generally under 500, and/or dollar volume of its business (for clarification, refer to 13 CFR Part 121 and FAR 19.102).

- **Handicapped/Sheltered Workshop** - this must be a charity organization or institution conducted not for profit, but for the purpose of carrying out a recognized rehabilitation program for handicapped workers and/or providing individuals with paid employment.

SUPPLIER DIVERSITY & BUSINESS DEVELOPMENT SUBCONTRACTING REPORT

Date ____________________
Contractor Name ____________________
Qtr. ____________________
Type of Business ____________________
Contract Number ____________________
Dollar Amount of Contract ____________________

CERTIFIED SMALL BUSINESS CONCERNS INFORMATION

List all small business concerns subcontractor(s) used on the project and subcontracted percent and amount

NAME	PRODUCTS/SERVICES TO BE PROVIDED	$ AMOUNT	YTD $ Amount	%	*SBC code

SOURCING EFFORT FOR CERTIFIED SMALL BUSINESS CONCERNS

List all small business concerns subcontractor(s) contacted on the project that will not be used

NAME	ADDRESS	PHONE NUMBER	CONTACT	*SBC code

LIST ANY ORGANIZATIONS, AGENCIES, OR GROUPS THAT YOU CONTACTED TO SOURCE CERTIFIED SMALL BUSINESS CONCERNS

NAME	ADDRESS	PHONE NUMBER	CONTACT

Attach sheet if additional space is needed.

Suggested Organizations:
Carolinas Minority Supplier Development Council 704-536-2884
South Carolina's Governor's Office of Small & Minority Business Assistance 803-734-0657
State of North Carolina Historically Underutilized Business Program 919-733-8965
Raleigh/Durham Minority Business Development Center 919-833-6122
The North Carolina Institute of Minority Economic Development 919-831-2467
National Association of Women Business Owners 703-506-326

NOT USED

FastPort Dataload Template

[redacted]

				PON codes will be shared at contract approval	PON codes will be shared at contract approval			PON codes will be shared at contract approval							PON codes will be shared at contract approval		PON codes will be shared at contract approval								

PEF-POD4-00195

090007 Hearing Exhibit - 00002721

PassPort Dataload Template
(Header Explanation)

[redacted]	Three character plant acronym as used in PassPort (e.g., Asheville = 'ASH', Roxboro="ROX")
[redacted]	The Unit No. that is to be used in the PassPort DID. For documents that apply to multiple units, this is the lowest common denominator unit number. This is procedurally refered to as the "Unit Base Rule". *Example:* If a drawing applies to Units 1, 2 and 3, the PassPort DID will contain reference to Unit 1. The additional units are entered into a Unit Table Array in PassPort (via the "Additional Unit Xrefs" data field below) to provide appropriate cross referencing of the document to the other units. For additional information on the "Unit Base Rule" please refer to procedure #EGR-POGX-00003 "POG Drawing Management & Control Program".
[redacted]	Any additional units that the drawing applies to (comma-separated, no spaces) for multiple unit references to a single drawing.
[redacted]	The original document number (e.g., vendor drawing number that appears in the drawing title block), as found on the document. In cases where more than one vendor drawing number resides on the drawing place both drawing numbers in the data field, separated by a coma followed by a space. For example, an old CP&L drawing number (X) that also has a B&W number on it (Y), would be entered as "X, Y"
[redacted]	The name of the primary vendor of the drawing. *Example:* If a drawing was developed by vendor "ABB" and is distributed by "Parsons Engineering" such that the document also displays a Parsons "DV" (vendor drawing) number, the drawing developer "ABB" is considered the "primary" vendor and Parsons is considered to be a "secondary" vendor. "Parsons" should be added to the "Additional Vendors" data field.
[redacted]	Add additional vendor names here (comma-separated, no spaces) to provide search capabilities for mulitple vendor references on a single drawing.
[redacted]	PassPort Document Type (i.e., Drawings = 'DRAW', Vendor Manuals = 'MAN', Specifications = 'SPEC'; Reports = 'RPT';
[redacted]	Subtype of Manual - Environmental = 'ENV'; Operating = 'OPM'; Vendor Technical Manual = 'VTM'; Program Users Manual = 'PUM'
[redacted]	Primary drawing discipline sub-type. Additional Sub-types can be added in this column in coma-delimited format. (i.e. E03, I03) Note: A/E or vendor drawing type matrix can be supplied and all translations (cross refernceing between the two codes) can be done by PGN
[redacted]	Vendor subtype applicable to Owner's Subtype

PassPort Dataload Template
(Header Explanation)

[redacted]	Type of Specification - EQUIP: Equipment; INSTL: Installation; MATRL: Material; SERVC: engr services (Inspection, test, engineering)
[redacted]	Specification Subtype - A: Architectural; C: Civil; E: Electrical; G: General; H: Chemical; I: Instr & Controls (Software); M: Mechanical; S: Structural
[redacted]	The drawing sheet number (as found on the document). If no sheet number, leave blank.
[redacted]	The document revision number (Alpha/Numeric), as found on the document. If no number, leave blank.
[redacted]	The document revision date, in format mm/dd/yy
[redacted]	PassPort document status (i.e., Active, Change, Superseded, History, Obsolete)
[redacted]	The actual title of the document (verbatum), as it appears in the drawing title block.

[redacted]	Additional information to be added parenthetically to the title (facilitate searching by keyword). **This information will need to be manually entered.** *Example:* If a vendor drawing has the title "Electrical Main One Line Diagram" it really doesn't provide much in the way of information to be used in narrowing a search in PassPort using the title data field. Therefore, one might want to add something like "(Roxboro Unit #4 SCR Project)" to further describe the title and make it more useful as search criteria. Refer to procedure #EGR-POGX-00003 "POG Drawing Management & Control Program" for more information on the "Title" data field requirements for the PassPort Metadata for drawings. **Note: It is prefered that the drawing be eventually revised to reflect the desired new title.**
[redacted]	The name of the electronic file, like a CADD file (e.g., "ROX001E0300002002004.dwg"), word document (e.g., "This Plan.doc"), etc.
	If populated, these System Code numbers will provide cross-referencing of the documents by System code. Multiple System Codes can be entered "comma-delimited" with no spaces between the codes.
[redacted]	If populated, these Equipment Type Code numbers will allow auto-linking of the documents to the Equipment. Multiple Equipment Codes can be entered "comma-delimited" with no spaces between the codes.
[redacted]	Attribute flag in PassPort denoting that the document requires perpetual Professional Engineering (PE) sealing upon future revisions ("Y" if applicable, leave blank if not)

NOT USED

PROGRESS PAYMENT RELEASE CERTIFICATE

KNOW ALL MEN BY THESE PRESENTS, THAT

WHEREAS, ("Contractor"), having its principal offices at , and (hereafter referred to as "Owner") have heretofore entered into a certain Contract, (the "Contract") dated relating to the furnishing of materials, labor and/or equipment for construction or services of (description of Contractor's Work in connection with a certain contract performed by Owner (the "Project") located at .

NOW, THEREFORE upon actual receipt by Contractor of payment from Owner in the sum of dollars ($) to Contractor, which sum represents the full amount due Contractor as of , . ("Release Date") less and except that retention in the amount of dollars ($) still being withheld by Owner all under and pursuant to the Contract, this document shall become effective to release pro tanto any mechanic's lien, stop notice or bond right that Contractor has on the project as of the Release Date. Contractor does hereby and thereby:

1. Certify to Owner that all persons, firms, associations, corporation, or other entities furnishing labor, materials, equipment, supplies or services to Contractor with respect to the Contract have been paid in full as of Release Date, including any and all applicable federal, state, and local sales, use, excise or similar taxes or import duties, licenses and royalties, except the following (none, unless noted): .
(attach additional page, if necessary, and so note)

and

2. Release and waive any and all manner of liens, whatsoever which Contractor, its successors or assigns may have upon any portion of the lands of Owner or the buildings thereon standing, or any personal or intangible property of Owner, for labor, material, equipment or services furnished under the Contract, as of Release Date, and

3. Further remise, release and forever discharge Owner, their successors and assigns of and from any and all manner of claims, demands, and causes of action whatsoever against Owner which Contractor, its successors or assigns may have for, upon or by reason of any matter, cause or thing whatsoever arising under or out of the Contract, as of Release Date, except the following (none, unless noted): .
(attach additional page, if necessary, and so note)

and

4. Agree to indemnify and hold harmless Owner, their successors or assigns, against all loss, cost, damage or expense by reason of any and all manner of liens, claims or demands which anyone may have for labor performed, or for materials, equipment or services furnished under the Contract as of Release Date, except as specifically noted.

IN WITNESS WHEREOF, Contractor has duly caused these presents to be signed and attested by its duly authorized owner, partner or officer (and, if a corporation, its corporate seal to be hereunto affixed) on the day of , 20XX.

CONTRACTOR

By ______________________________

Title ______________________________

Contract No. 433059: Part I: Attachment J

FINAL PAYMENT RELEASE CERTIFICATE

KNOW ALL MEN BY THESE PRESENTS, THAT

WHEREAS, ("Contractor"), having its principal offices at , and (hereafter referred to as "Owner") have heretofore entered into a certain Contract, (the "Contract") dated relating to the furnishing of materials, labor and/or equipment for construction or services of (description of Contractor's Work in connection with a certain contract performed by Owner (the "Project") located at .

NOW, THEREFORE upon actual receipt by Contractor of payment from Owner in the sum of Dollars ($), which sum shall represent payment in full and final payment due to Contractor under and pursuant to the above-referenced Contract resulting in a total Contract price of Dollars ($), Contractor does hereby:

1. Certify to Owner that all persons, firms, associations, corporation, or other entities furnishing labor, materials, equipment, supplies or services to Contractor with respect to the Contract have been paid in full as of Release Date, including any and all applicable federal, state, and local sales, use, excise or similar taxes or import duties, licenses and royalties, except the following (none, unless noted):

(attach additional page, if necessary, and so note)

and

2. Remise, release, waive, relinquish and forever quitclaim unto Owner, its affiliates, successors and assigns, any and all manner of liens, claims or demands whatsoever which against Owner, Contractor ever had, now has, or which it or its successors or assigns hereafter can, shall or may have upon any portion of the lands of Owner or the buildings thereon standing, for labor, material, equipment or services furnished under the Contract, and

3. Further remise, release and forever discharge Owner, their affiliates, successors and assigns of and from any and all manner of liens, claims, demands, and causes of action whatsoever against Owner which Contractor ever had, now has, or which it or its successors or assigns hereafter can, shall or may have for, upon or by reason of any matter, cause or thing whatsoever arising under or out of the Contract, and

4. Agree to indemnify and hold harmless Owner, their successors or assigns, against all loss, cost, damage or expense (including but not limited to attorneys' fees) by reason of any and all manner of liens, claims or demands which anyone may have for labor performed, for material, equipment or services furnished, or by reason of any matter, cause or thing whatsoever arising under or out of the Contract.

IN WITNESS WHEREOF, Contractor has duly caused these presents to be signed and attested by its duly authorized owner, partner or officer (and, if a corporation, its corporate seal to be hereunto affixed) on the day of , 20XX.

CONTRACTOR **NOTARY PUBLIC SEAL**

By

____

Title

____

NOTICE OF ACCEPTANCE

Project: ____________________ Location: ____________________

Contract: ____________________

Contractor: ____________________

Notice of Acceptance Number: ____________________ Date: ____________________

NOTICE is hereby given to the above named Contractor that the Work performed by Contractor pursuant to the above Contract for said Project is accepted as of the below stated date for and only for: (check applicable)

- ☐ Purposes of final payment under said Contract.
- ☐ Purposes of final acceptance of said Work under said Contract.
- ☐ Acceptance of this Work is contingent upon Contractor completing the following incompleted Work by . If such Work is not completed by this date, this acceptance shall be void and as if never given.

This notice shall not relieve Contractor of any responsibilities under the guarantee provisions of the Contract.

Dated: ____________________

Signed: ____________________ (Owner)

____

____

____

ATTACHMENT L
NOTICE OF COMPLETION

Project:	______________________	Location:	______________
Contract:	______________________		
Contractor:	______________________		
Notice of Completion Number:	______________	Date:	______________

NOTICE is hereby given by the above named Contractor that pursuant to Section 17.0 NOTICE OF COMPLETION AND FINAL ACCEPTANCE of Part I, of the above Contract for said Project all work for the above referenced Work Release is complete.

Date: ______________________________

Signed: ______________________________ (Contractor)

STANDARD WARRANTY TERM

Contractor warrants to Owner that the cooling tower will be free from defects in material, workmanship and design under normal use and service for a period of twenty-four (24) months after Mechanical Completion. In addition to the rules set forth in Part I Section 4.0 Warranty, the following shall apply when Contractor is required to perform Work under the provisions of Part I Section 4.0 Warranty:

1. Written notice of the defect is given to Contractor within thirty (30) calendar days of discovery thereof;
2. The equipment has been operated in accordance with the operating and maintenance instructions provided by Contractor; and no alterations or substitutions have been made in the equipment without the express written authorization of Contractor.

10-YEAR FRP PULTRUDED STRUCTURE WARRANTY

Contractor warrants the pultruded FRP structure against any defects in material and workmanship under normal use and service for a period of ten (10) years after Mechanical Completion. Contractor's obligation under this warranty is to supply, pursuant to the delivery terms of the proposal, replacement parts for those parts which are shown to have been defective as to material, workmanship or design, provided that:

1. Written notice of the defect is given to Contractor within thirty (30) calendar days of discovery thereof;
2. The equipment has been operated in accordance with the operating and maintenance instructions provided by Contractor; and no alterations or substitutions have been made in the equipment without the express written authorization of Contractor

ATTACHMENT N

Progress Energy

AFFIDAVIT OF EXEMPTION

Florida Power Corporation (dba Progress Energy Florida, Inc.) hereby states and affirms that it is acquiring machinery and equipment and other qualifying property; or labor and/or parts for the necessary repair, maintenance, or replacements of machinery and equipment and other qualifying property, for use at its generation facilities, from ________________________, which is necessary for the production of electrical or steam energy resulting from the burning of boiler fuels other than residual oil and is exempt from the tax imposed by Chapter 212, Florida Statutes, Sales and Use Tax Act, pursuant to Section 212.08(5)(c), Florida Statutes.

NOTE: The units at the Anclote, Bartow and Suwannee generation facilities which operate on residual oil (No.6 oil) are excluded from this exemption.

I understand any person furnishing a false affidavit to a vendor for the purpose of evading payment of any tax imposed under Chapter 212, Florida Statutes, shall be subject to the penalty set forth in section 212.085, Florida Statutes, and as otherwise provided by law.

IN WITNESS WHEREOF, the undersigned duly authorized agent of Florida Power Corporation, does hereby execute this Affidavit this 21st day of September, 2007.

Jocelyn Thornton — Jocelyn Thornton
Name of PGN Employee — Signature of PGN Employee

Chief Procurement Officer — Ophelia Mason Taylor
Title of PGN Employee — Notary

Notary Public
Wake County
State of North Carolina

PLEASE NOTE THAT FLORIDA POWER CORPORATION PURCHASES BOTH TAXABLE ITEMS, AND TAX EXEMPT ITEMS PURSUANT 212.08(5)(c), F.S., FROM YOUR COMPANY. A STATEMENT WILL BE INCLUDED WITH EACH TAX EXEMPT PURCHASE ORDER. THEREFORE, THE ATTACHED AFFIDAVIT OF EXEMPTION SHOULD ONLY BE USED WHEN PURCHASE ORDERS STATE THIS EXEMPTION APPLIES. THIS AFFIDAVIT IS VALID UNTIL REVOKED IN WRITING. AN EXPIRATION DATE DOES NOT APPLY.

Progress Energy Tax Department
410 S. Wilmington Street, Raleigh, NC 27602
(919) 546-2886

ATTACHMENT O

Progress Energy

POLLUTION CONTROL EQUIPMENT

Florida Power Corporation (dba Progress Energy Florida, Inc.) hereby states and affirms that it is acquiring machinery and equipment or other qualifying property, for use at its generation facilities, from ________________________, and will be primarily used for the control or abatement of pollution or contaminants in the manufacturing, processing, compounding, or production of tangible personal property for sale. Further, the undersigned declares that said items are required pursuant to a law implemented by the Florida Department of Environmental Protection (DEP), or required under the condition of a permit issued by DEP.

I understand any person furnishing a false affidavit to a vendor for the purpose of evading payment of any tax imposed under Chapter 212, Florida Statutes, shall be subject to the penalty set forth in section 212.051(1), Florida Statutes, and as otherwise provided by law.

This certification relieves the vendor from the responsibility of collecting tax on exempt amounts. The Department looks solely to the purchaser for recovery of tax if the purchaser was not entitled to the exemption.

IN WITNESS WHEREOF, the undersigned duly authorized agent of Florida Power Corporation, does hereby execute this Affidavit this 21st day of September, 2007.

Jocelyn Thornton
Name of PGN Employee

Jocelyn Thornton
Signature of PGN Employee

Chief Procurement Officer
Title of PGN Employee

Ophelia Macon-Taylor
Notary

[illegible]
Notary Public
Wake County
State of North Carolina
My Commission Expires Apr 22, 2011

Progress Energy Tax Department
410 S. Wilmington Street, Raleigh, NC 27602
(919) 546-2886

Crystal River Unit 3 Project
Project Organization

12/8/2008

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Project Manager

Quality Management
Joe Whalen
Vice President, Engineering & Operations

Engineering
* **John Ahern**
VP Engg/Engineering Manager

Ron Forest
Engineering Technician Supervisor

Procurement
* Randy Beery
Procurement Manager

On Site Construction
* **Mike Corbett**
EvapTech Site Manager

Raymond Oliver
General Foreman

Non-Union Labor
Craft Personnel

Pat Williams
Safety Coordinator

* Progress Energy shall participate in decisions related to selection and/or replacement of these personnel

Contract No. 433059

Part II

Statement of Work

Contractor's Scope of Work shall consist of the entirety Task 5a, Tasks 1, 2, 3, and 4 as relative to the performance of Task 5a, and all planning and interfaces as necessary to fully perform the Work.

STATEMENT OF WORK

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STATEMENT OF WORK

INTRODUCTION / BACKGROUND

Owner's Crystal River Nuclear Unit 3 (CR3) is part of the larger Crystal River Energy Complex (CREC) located in Citrus County, Florida. The CREC is comprised of 4,738 acres and includes a single nuclear unit (CR3) and four coal-fired units, CR 1, 2, 4, and 5. CR3 and the four coal-fired units lie in the developed area of the site.

Cooling water for CR 1, 2, and 3 is withdrawn from an intake canal which connects to Crystal Bay and the Gulf of Mexico and returned to the Gulf via a common Discharge Canal. The Florida Department of Environmental Protection (FDEP) Issued a National Pollution Discharge Elimination System (NPDES) permit (FL0000159) with limits on the combined condenser flow from CR I, 2, and 3 to 1,898 million gallons per day (MGD) during the period of May 1 through October 31, and 1,613.2 MGD during the remainder of the year.

The 14-mile-long intake canal is dredged to a depth of approximately 20 feet (ft) to also accommodate coal barges which unload and dock on the south side of the Intake Canal, just west of the intakes for CR 1 and 2. The Intake Canal is bermed by northern and southern dikes. The northern dike continues along the channel for another 5.3 miles. There are openings in the dikes at irregular intervals to allow north-south boat traffic in the area of CREC. Movement of water into the canal is tidally influenced. At the mouth of the canal, current velocities ranged from 0.6 to 2.6 feet per second (fps) when last measured in 1983-1984.

Studies have demonstrated that in order to reduce Owner's total fuel cost, increased efficiencies can be realized from technological advancements and system modifications to increase generation capacity from the company's lowest cost fuel source. Following Owner's request, the Florida Public Service Commission (PSC) has determined that a power uprate is an economical option to add capacity and power output to the existing nuclear unit, CR3. The CR3 Uprate Project will result in economic benefits to customers and the community by providing additional clean energy at lower cost to consumers. An increase in the plant's gross output from 900 MW to 1,080 MW can serve the equivalent of an additional 110,700 homes.

The CR3 Extended Power Uprate (EPU) Project will occur over two phases. The first phase (Phase I) will occur during a 2009 planned refueling outage and scheduled steam generator replacement. The improvement to the turbine center line components will increase the efficiency of power production resulting in decreasing consumer costs. The second phase will result in an additional 140 MW of power and will require a large number of smaller yet substantial modifications to assure long term reliability of all plant systems at the conditions necessary to support a higher licensed power level.

The work identified in this statement of work (SOW) is to obtain the services necessary to design, procure, and construct (as identified below) the necessary Discharge Canal cooling equipment to mitigate the increased thermal heat rejected into the Discharge Canal by CR3 and to replace the heat removal capacity of temporary cooling equipment.

DESCRIPTION OF WORK – GENERAL

Owner requires Contractor to design and develop, procure, and construct the New EPU Cooling Tower as defined below so as to provide a minimum of 2.33 B BTUs/Hr heat removal from the Discharge Canal water prior to the water's return back to the Gulf of Mexico as identified below. The heat removal is required in order keep the water temperature below the NPDES three hour rolling average limit of 96.5^{0}F. The Design Criteria Manual and associated specifications, calculations, modeling, studies, and drawings were generated during the Study Phase of this Project. Contractor shall update the Study Phase conceptual design documents such that they will become the final design documents to be used for the Project's procurement of materials and construction.

The Work is broken down into work tasks. For this Contract, Contractor shall perform Task 5a and the associated Work necessary therefore, including but not limited to Tasks 1, 2, 3, and 4. Tasks 6a, 7a, 8a, and 10a will be performed by a different vendor under a separate contract. However, these tasks are included in this Statement of Work to provide clarification and guidance relative to Contractor's necessary interfaces and the information Contractor will be required to provide to Owner and the vendor performing these other tasks.

The major tasks are stated below. Details of each work task are provided in Section 3 of this document, in the Design Criteria Manual, and in the appropriate specifications.

- <u>New EPU Cooling Tower</u> – This scope includes engineering, procurement, construction of the EPU cooling tower, & startup testing. Performance testing will be done by an independent third party under a separate contract. The cooling tower Contractor will support the performance testing. The cooling tower is defined as the support structures and associated equipment attached to and located above the cooling tower cold water basin. The cooling tower is further detailed in Section 3 of this document, the DCM, and Specification S2a, incorporated herein as Attachment B to Part IV of this Contract.

    - The boundary of the EPU cooling tower is at the cold water basin. The Contractor completing the cooling tower must:

        - provide the engineering detail for each interface point of the cooling tower with respect to the cooling tower basin,
        - complete the mechanical work up to and including the first flange off the cooling tower,
        - the first flange connection includes the flange, gaskets, and isolation valve and operator,
        - complete all the design, procurement and construction for low voltage electrical ($\leq$ 480 v circuits) components, including wiring terminations at the

first electrical panel off the cooling tower (including providing and installing the first electrical panel off the cooling tower),

    - complete all the design & procurement specifications for electrical work supporting high voltage (≥ 480 v circuits) components located on the cooling tower. The cables to the high voltage equipment will be pulled to the cooling tower and terminated at the equipment by the intake structure work scope.
    - complete the design, procurement and construction of all support systems located on the cooling tower (i.e. lighting, etc.).
  - Complete the design for monitoring and controls of cooling tower fans, pumps, and related equipment.

- **EPU Cooling Tower Basin & Foundations** – The scope of this work is to engineer & design the new EPU cooling tower cold water basin and foundations as defined below. Construction will be completed under a separate contract. The detailed requirements for this work are stated in Section 3 of this document and the DCM. The basin and foundations are defined as all concrete components and structures necessary to support the installed cooling tower and to facilitate proper hydraulic operation of the cooling tower system. The technical requirements for this work include:

  - Design of the basin and foundations subject to the following boundary conditions:
    - the Contractor that is awarded the basin and foundation design work will base his design on the cooling tower Contractor's loading diagram and mounting & support requirements. The design and engineering details of all interfaces between the cold water basin and the cooling tower structure will be developed by the cooling tower Contractor,
    - one physical boundary of this scope is up to and including the first flanged connection (with isolation valve & controls),
    - a second physical boundary of this scope is up to & including the first electrical box off the cooling tower maintenance area,
    - this scope includes the 40' maintenance area around the circumference of the cooling tower basin,
    - the cooling tower basin height will be adequate to allow gravity drain back to the Discharge Canal or to the Intake Canal (the intake canal connection will be blanked off).
  - the cooling tower and basin design will allow for easy access and cleaning of marine growth from the basin and cooling tower structural members.
  - maintenance area (approximately 40' perimeter around the cooling tower basin),
  - electrical and instrumentation panels, conduits, cable trays, supports and restraints, for components mounted on the cooling tower basin or maintenance area,

- o the design will include appropriate maintenance handling equipment and systems,
- o some geotechnical soil characterization has been done by Owner. The Contractor is responsible for reviewing this information and finalizing the characterization as necessary to complete the cooling tower design.

- **<u>Intake & Discharge Structures</u>** – The scope of this work is to engineer & design the intake and discharge structures. The scope of work for the intake and discharge structures are further detailed in Section 3 of this document, the DCM, and specifications for equipment within this scope of work (i.e., S-4 – Trash Racks & Traveling Screens, S-5 Concrete, S-6-1 Fiberglass Reinforced Piping, S-6-2 – HDEP Piping, and others). The boundary of this task is defined as follows:

    - o Design requirements and drawings of termination detail for high voltage cables on the cooling tower equipment,
    - o Design requirements and drawings of termination detail for low voltage wiring at the first panel off the cooling tower,
    - o Design of cable and wire ways to the cooling tower basin and to the cooling tower motors,
    - o Design requirements and design for electrical power from the substation to the distribution center in the intake structure,
    - o Design requirements and design detail of instrumentation and controls to the Unit 1 / 2 control room DCS.
    - o Piping to and from the cooling tower basin,
    - o The scope of this work also includes all geotechnical sampling required to complete the final design of the intake and discharge structures.

- **<u>Monitoring & Control Software & Hardware</u>** – The scope of this work is to design and develop the software and hardware for the equipment monitoring and control system for the new cooling tower equipment. The monitoring and control system must be compatible with the existing cooling tower Distributed Control System (DCS). The features of the monitoring and control system must be similar to the existing equipment. The Contractor will work closely with Owner personnel in completing this work.

The Contractor will provide the technical and engineering expertise to design and develop the procurement specifications for the cooling equipment and systems identified above and further described in section 3 of this document and in the Design Criteria manual.

The Contractor will develop & implement the associated calibration and test procedures to demonstrate proper equipment capabilities during equipment and component startup.

The Contractor will supply all management, supervision, labor, equipment, materials, tools, consumable supplies, and each and every item necessary to perform the Work describe in this Contract.

The Contractor will perform both on-site and off-site activities necessary to complete the stated design and develop procurement specifications.

On site activities require preapproved access. The Contractor will submit site access forms 48 hours before expected CREC access unless otherwise approved by the Designated Representative.

The result of this Contract will be the final design for the installation and operation of Discharge Canal cooling equipment that provides a minimum of 2.33 B BTU/Hr of Discharge Canal heat removal.

DESCRIPTION OF WORK – SPECIFIC

The design criteria for this section is contained in the Design Criteria Manual (DCM) included in this Contract as Attachment A to Part IV. The Contractor will maintain the DCM up to date as the final design is completed.

The Contractor will design the equipment and systems described below. The Contractor will also review and update the specifications for all the project materials. New specifications may be required to be generated by the Contractor to meet this requirement. The Contractor will also generate a list of potential vendors for each specification.

Task 1 Update and Maintain the Design Criteria Manual

The Design Basis of the DCM must be updated and maintained as the engineering design and procurement specification generation is completed. This task is a component of tasks 5 through 10.

The Design Basis was developed from information evaluated during the Study Phase of the Project. During the Project's Study Phase two important activities were completed. First, an Alternatives Analysis was completed. The Alternatives Analysis identified potential thermal mitigation technologies that could be used to reduce the thermal energy of the Discharge Canal water. The Alternatives list was then narrowed to the technologies that could be used at Crystal River. The technologies were then run through heat balance modeling to determine the optimal solutions and to provide a recommendation for further development in the second Study Phase task (conceptual design). The conceptual design further refined the alternatives analysis decision, defined the location of the cooling equipment, identified the equipment support utilities, stated the design standards for further design, developed design specifications for long lead items, and generated conceptual design drawings.

The Design Basis contains the Project's Design Requirements Section. The other DCM sections are developed based on the Design Requirements. As the final design evolves, the Contractor must revise the DCM Design Basis to maintain the design requirements in line with the current project directions.

Task 2 Update & Maintain Procurement Specifications

The Project Specifications of the DCM must be updated and maintained as the engineering design and procurement specification generation is completed. This task is a component of tasks 5 through 10.

The DCM also contains the Project's draft procurement specifications for long lead items. The procurement specifications for items identified as long lead were drafted during the study phase. The Contractor must update the long lead procurement specifications as soon as is feasible and identify potential vendors for each specification.

Task 3 Update & Maintain Project Design Drawings

The Project Drawings (contained in the DCM) must be updated and maintained as the engineering design and procurement specification generation is completed. This task is a component of tasks 5 through 10.

The Project drawings of the conceptual design are currently attached to the DCM. These drawings are to be revised and new drawings added during the final design effort.

Task 4 Provide Construction Guidelines & Test Procedures

The Construction Guidelines and Test Procedures (to be contained in the DCM) must be updated and maintained as the engineering design and procurement specification generation is completed. This task is a component of tasks 5 through 10.

All the construction guidelines, test procedures and special instructions generated for and implemented for the construction effort are to be maintained in the DCM. The construction guidelines and special instructions will be revised by the Contractor as the final design is completed.

Not Used

Task 5a Design & Construct the EPU Cooling Tower & Update Calculations (Clarifier Pond)

The Contractor must comply with specification (S2a) and the below requirements in designing and constructing the EPU cooling tower. The Contractor will update design calculations (C2 & C2a) in completing this work. The cooling tower specification incorporates the design requirements for the EPU cooling tower. The desired mechanical draft cooling tower design requirements are summarized as follows:

- complete tasks 1 through 4 as they relate to this task,
- revise specification S-3 – lift pumps, as an early task,
- the cooling tower will be a circular counterflow multi-fan design,
- the cooling tower will be located where the percolation clarified pond is now located,
- the cooling tower will provide a minimum heat rejection capability of 2.33 BBTU/Hr at an approach temperature of 11.0°F to an ambient wet bulb temperature of 79.0°F and a flow capacity of 320,000 gpm.
- the cooling tower fill is to be splash or trickle fill material that provides for easy maintenance and reliability,
- the cooling tower will have drift eliminators that limit drift to ≤.0005%,
- the construction material will be concrete with corrosion resistant coated rebar or pultruded composite FRP with high strength stainless steel fasteners or other material that withstand the harsh saltwater environment over a 30 year operating life,
- individual cooling tower fan cells must be capable of being taken out of service without shutting down the remainder of the cooling tower (isolation of air and water to individual cells)
- the cooling tower and maintenance area must fit within the area currently occupied by the clarifier pond and adjacent roads. The adjacent roads will become part of the maintenance pad around the new cooling tower.
- fans will be monitored and normally controlled from the control room,
- fan local operation will available for fan testing,
- local and remote control room monitoring instrumentation will provide operating status, fan current, fan vibration, bearing temperature, motor temperature,
- fan local instrumentation will have operating status motor & fan oil level,

- o local and remote control room instrumentation for equipment controls will provide operating functions for the cooling tower pumps, fans, and valves,
- o the cooling tower will be supplied with visual observation ports to observe the cooling tower fans,
- o the cooling tower and basin must be designed to provide easy access for cleaning of marine life from the basin and cooling tower structural members,
- o cooling tower riser isolation valves will have 480 volt motor operators. The valves will normally be remotely controlled but, will be capable of local and manual operation,
- o the cooling tower will have a walkway through the air inlet sector that allows personnel access to the cooling towers inter ring header area from grade level,
- o the cooling tower will have a permanent personnel walkway access to the spray nozzles for maintenance and inspection,
- o the cooling tower will have personnel access to one of the cooling tower cells for thermal performance monitoring,
- o the cooling tower will have an internal ring header to direct water to the cooling tower risers. The supply piping & ring header will be supplied by another contractor. Design details of the risers are provided as part of this task. The risers installation is part of this task.

Not Used

Task 6a Design the EPU Cooling Tower's Basin and Surrounding Laydown Area (Clarifier Pond Location)

The Contractor will complete the cooling tower basin scope as follows:

- o Complete tasks 1 through 4 for the affected sections, related to this task.
- o Subsurface Investigation - All soil investigation work shall be the responsibility of the Contractor
  - ▪ Borings in soil, recovery of samples, tests on samples, or other soil investigations and exploratory procedures shall be performed as necessary for the design and construction of the EPU cooling tower foundations.
  - ▪ The number and size of soil samples, the methods of obtaining samples, and the field and laboratory tests and records for determining and recording the soil data shall be those that are usual and customary in the field of foundation engineering and are necessary and appropriate for the safe design of the foundations. As a minimum, the soil parameters that affect the stiffness and lateral load capacity of the deep foundation components shall be determined and strength and settlement parameters shall be determined for the design of foundations on soil.
- o Cooling Tower Site Preparation

- Contractor shall prepare the cooling tower site, providing backfill, excavation, grading and compaction as required to stabilize the sites.

Basin Outlet Structure -

- o The cooling tower cold water basin shall be a watertight structure. The height of the cooling tower basin and outlet structure curb shall be sufficient to prevent splash-over during normal operation. Water stops shall be installed at all construction and expansion joints to prevent leaks. Contractor shall have a geotechnical survey performed to establish foundation requirements.
- o The cold water basin shall be designed for control of cracking. The average calculated crack width under service conditions shall not exceed 0.013 inch. The average crack width shall be computed from:

  - $W = 0.076\, R\, f_s \sqrt[3]{d_c A}$

  where:

  W = The average crack width in units of 0.0001 inch
  R = Ratio of distances to the neutral axis from the extreme tension fiber and from the centroid of the tension reinforcement
  f_s = Calculated stress in the reinforcement at service, ksi (including temperature and shrinkage loads)
  d_c = Thickness of concrete cover measured from the extreme tension fiber to the center of the bar located closest thereto which is perpendicular to the crack
  A = $2d_c$ times the spacing of the reinforcement

Basin Foundation –

- o The foundations for the EPU cooling tower shall be completely suitable for the structure, the loads, the subsurface conditions and the service.
- o Foundation settlements shall be investigated and their effects provided for in the structural design and in the construction details.
- o If piling is to be used for the basin, fill, and water distribution system foundations, at least one satisfactory load test shall be made for each size pile at each tower location.

Construction Guidance

- o Forms shall conform to the lines and dimensions called for on approved Contractor's drawings. They shall be substantially and properly braced and supported so as to maintain their position during thorough compaction of the concrete with internal vibrators and shall be sufficiently tight to prevent leakage of water.

- o No construction load shall be supported upon, nor any shoring removed from, any part of the structure under construction until that portion of the structure has attained sufficient strength to adequately support its weight and the loads placed thereon.
- o Forms shall be removed and reset in such a way as to avoid damage to the concrete and to avoid disturbing reinforcement projecting above any concrete section to such an extent as to break the bond between this reinforcement and the recently placed concrete.
- o Forms shall be designed to permit uniform spacing of horizontal and vertical joints where practical.

- o Forms for exposed surfaces shall be such as to provide a smooth plane concrete surface equivalent to rough or board form finish as specified in Section 10.2 of ACI 301.
- o gravity return of cooled water to the Discharge Canal,
- o cooling tower basin allows for easy access and maintenance for marine growth removal
- o relocate electric utility as necessary to provide for safe construction and maintenance, Owner will provide direction for new routing,
- o the maintenance area has a minimum of 40' width surrounding the cooling tower basin to the edge of the paved maintenance area,
- o the maintenance area will provide for traffic around the cooling tower when maintenance is not being performed,
- o a retention wall will be designed to maintain the necessary separation from the percolation pond and the cooling tower area however the wall will allow for the necessary over flow from the percolation pond,
- o the percolation over flow will be directed around the cooling tower basin to the Discharge Canal, Task 8a will direct the water from the cooling tower basin to the discharge structure,
- o the Contractor will include a storm water run-off design that maintains the existing storm water collection basin (east of the cooling tower) operational. The storm water will be collected and pumped to the percolation pond system,
- o the cooling tower basin will include pipe support saddles for a water supply ring header to be supplied and installed by the cooling tower Contractor, the support saddles will be constructed on a concreted pad within the cooling tower basin.

Not Used

Task 7a Design Intake Structure and Related Systems (Clarifier Pond Location)

The Contractor must use the conceptual design information in the DCM & complete the design of the intake structure and related equipment and systems for the cooling tower. The following is a summary of the intake structure design requirements:

- Complete tasks 1 through 4 for the affected sections, related to this task.
- The intake structure will be located on the discharge canal just north of the cooling tower,
- This task will develop procurement specifications (many draft specifications are drafted and need to be completed/updated) for all the material required to support this task.
- Defined as the intake structure on the Discharge Canal and the piping (with valves, expansion joints, restraints, and supports) between the intake structure and the cooling tower basin. This scope includes items listed below.
- The physical structures at the discharge canal,
- The maintenance and equipment handling equipment required off the cooling tower maintenance area (i.e. breaker handling removal, traveling screen removal, pump maintenance & isolation).
- The piping fill & priming system,
- The AC electrical system from the CREC substation to the electrical transformers, through the electrical distribution panels, and to the equipment or to the first electrical panel off the cooling tower maintenance area (including ETAP analysis),
- The DC electrical system,
- The instrumentation monitoring & controls system from the equipment or the first instrumentation panel off the cooling tower maintenance area, back to the local and remote control rooms,
- The local area lighting,
- Service water system,
- Compressed air system,
- the intake structure will have dual flow traveling screens to filter the water, one traveling screen for each lift pump, the traveling screen will have:
  - through screen velocity of < 0.5 feet per second flow at mean tide level,
  - Local and remote control room operation functions (primary operation will be from the remote operating console),

    - Control room instrumentation that indicates operating status, operating current, lift pump intake temperature, and differential screen pressure,
    - Local instrumentation that includes operating status, operating current, and differential screen pressure, and visual observation window to view the traveling screen surface. (see DCM for additional requirements),

- the intake structure will have a dual flow traveling screen wash system,
    - the screen wash system will be operated remotely with the capability of local operation,
    - the screen wash system will have appropriate wash material handling equipment, return piping, baskets and containers,
    - screen wash system instrumentation will include pump operation status & spray header pressure,
- the intake structure will have lift pumps (the number and size to be calculated by the cooling tower Contractor), the lift pumps will:
    - normally operate 3 to 4 pumps that have the capacity to provide the total amount of cooling tower flow,
    - have excess lift pump capability that can supply 100% backup capacity of normally operating lift pumps,
    - be normally operated from the control room but have remote operation capability for testing,
    - Configured with instrumentation to remotely monitor bearing temperatures, motor temperature, motor current, and pump flow.
- The Contractor's intake structure design will have a weather enclosed and climate controlled housing for transformers & electrical switchgear and distribution panels, the enclosure will have breaker handling equipment, adequate lighting and room to properly maintain the switchgear. The height of the electrical equipment will be above the storm surge level or otherwise protected.
- The design for this task will include all the electrical equipment procurement specifications, installation details, electrical single line drawings, schematics, and other design documents needed to power all the equipment installed for the cooling tower, intake structure equipment and related system systems.
- The Contractor's design will also include piping, pipe supports, and restraints between the cooling tower and the intake structure.
- The water supply to the cooling tower will terminate internal to the cooling tower basin with flanged connections designed to attach to the cooling tower ring header.

Not Used

Task 8a Design Discharge Structure and Related Systems (Clarifier Pond Location)

The Contractor must use the conceptual design information in the DCM & complete the design of the Discharge Structure for the cooling tower. The following is a summary of the Discharge Structure design tasks and requirements:

- Complete tasks 1 through 4 for the affected sections, related to this task.
- The design Contractor will develop a design and cost estimate for piping and supports from the cooling tower basin to the discharge canal structure located west of the Helper cooling tower intake structure.
- The Contractor's discharge structure design will return flow in such a manner that the water will not be entrained with the HCT intake water,
- this design will include the piping, valves, and supports for piping returning water to the discharge canal, the design will be such that the construction and final installation will not interfere with site traffic.
- The design must be to return the water such that the water will not erode the canal bank at the local point of discharge or further along the canal flow path.
- The design will include incorporation of flow from the percolation pond over flow from the cooling tower basin to the discharge structure.
- The design for this task includes development of a system to help predict the POD temperature as an operator aid.

Not Used

Not Used

Task 10a Design Software & Hardware to Interface with Existing DCS (Clarifier Pond Location)

The Contractor will develop software and hardware as necessary to allow local and remote monitoring and control of the new equipment installed by this Project.

- Complete tasks 1 through 4 for the affected sections, related to this task,
- To the extent possible the software and equipment should be off the shelf material,
- The monitoring and control display should look and have the same type of control feel as the existing equipment,
- The control system will be for all the newly installed equipment and systems

Not Used

Special Requirements

The Discharge Canal cooling equipment being designed and constructed for this effort will be in a harsh salty environment. The materials of construction must be corrosion resistant in this environment. For example; exposed metal will be monel or 316 stainless steel, & rebar will be coated steel. Other exposed material will be UV protected pultruded composite FRP or equivalent. Electrical distribution equipment should be protected by placing it in an environmentally controlled facility.

The Contractor will identify potential vendors for procurements. The Contractor will identify all the material handling equipment and equipment short term storage requirements.

Organizational Interfaces

The Contractor shall interface with various Owner organizations through the Owner Designated Representative (or designee) as identified in the organization chart and work process plan.

The Contractor will complete the engineering design and provide specific instruction to tie-in new equipment and systems to existing CREC systems. The Contractor will also develop test instructions for component functional testing, startup testing, and performance testing.

Owner Furnished Materials and Equipment

The following materials and equipment will be furnished by Owner at no cost to the Contractor:

Owner has obtained subsurface characterization and geotechnical testing of the proposed cooling tower location. This information will be provided to the Contractor.

The Contractor is responsible for verification that all procurement specifications are adequate and that they will obtain the correct equipment needed for the project. The Contractor's verification of procurement specifications will be completed during the first 4 months of the engineering phase.

Site Conditions and Known Hazards

The Crystal River Energy Complex (CREC) is an industrial facility with continuing operations other than this project. Potential Hazards associated with this Project are as follows:

- The work area is within a security area. Un-escorted access to the work area requires facility specific training and an authorization badge.
- There are several other projects and operations that will have activities continuing in parallel with this project. Due to the number of site activities the traffic on the CREC facility and nearby areas will make traffic to and from the work area a hazard.

TECHNICAL REQUIREMENTS AND ACCEPTANCE CRITERIA

The Work to be completed as a part of this Contract is defined in Section 3 of this document and in the Design Criteria Manual. The Design Criteria Manual (DCM) will contain the design requirements that are to be used as the project's final design documentation. The design documents will contain construction implementation requirements and standards. Equipment and component specific requirements have been rolled into the drafted procurement specifications attached to the DCM. The DCM will be expanded by the Contractor, during the final design work, to become the design basis document for the

Project. The documents generated for and contained within the DCM will become the Project's construction documents.

The scope of the DCM covers all the design elements of the project. The DCM will be expanded from the design basis requirements during the final design and will house all the procurement specifications, engineering calculations, and drawings for the project.

The design criteria manual is divided into 8 design sections and three major Attachment sections as described below:

- Section 1 – Introduction and Plant Description
- Section 2 – General Design Criteria
- Section 3 – Architectural, Civil, and Structural Design Criteria
- Section 4 – Electrical Design Criteria
- Section 5 – Instrumentation and Controls Design Criteria
- Section 6 – Mechanical Design Criteria
- Section 7 – Plant Design Criteria
- Section 8 – Environmental Design Criteria
- Attachment 1 – Procurement Specifications and design calculations
- Attachment 2 – Project Drawings
- Attachment 3 – Construction Guidelines and test procedures

Design Interfaces

The design will potentially interface with the following CREC site systems and additional Project personnel:

- Electrical substation
- Electrical building and switchgear at the HCTs.
- Unit 1 Control Room DCS and DCS remote consoles in CRS Main Control Room and existing HCT control room,
- Waste water piping from Unit 1, 2, & 3.
- Potable water system
- Electrical distribution (4.16 KV, 480 V, & 120V, etc.) local to the work facilities
- Telephone distribution system
- The design implementation will require obtaining CREC Operations personnel input.

The design requirements are well defined in the Design Criteria Manual with the exception of the following.

- Equipment monitoring, controls, and display functions. The Contractor will work with Owner's personnel in developing the hardware and software to communicate and interface with the existing Distributed Control System (DCS). The new indication and controls must look and operate similar to the existing control room equipment.

- o Additional electrical power will be distributed from the onsite electrical substation. The specific design of the modifications will require close work with the Progress Energy Florida (Owner) Transmission Group. The Owner Transmission Group will design and modify the substation equipment. The Contractor's designed equipment will tie into the substation provided disconnect. Owner Transmission will make the final tie-in at the CREC substation. The Contractor will re-do the ETAP analysis as part of the final design.
- o Another design and construction interface is with PMI Ash. PMI Ash loads ash from the southeast tank and transports the ash to another location. A transportation route will need to be maintained open by the Contractor during the construction of the cooling tower. The design for the cooling tower basin and cooling tower must make provisions to maintain PMI Ash transportation capabilities.
- o The access around the construction site will also be used by other CREC operations for;
    - Security Patrols,
    - Access to percolation ponds,
    - Access to maritime transportation security administration offices,
    - And others.

Codes and Standards

Unless specified otherwise, the current edition or revision of the code in effect on the date of award shall be used. Applicable codes and standards have been identified in the DCM and draft specifications.

Specifications

Specifications for several of the long lead items were drafted during the conceptual design phase of the project. The Contractor is responsible for validation of the specifications as an early part of this work (within 4 months of NTP). The long lead items will then be procured in parallel with completing the final design.

The draft specifications are located in the DCM. New and revised specifications are to be maintained as part of the DCM by the Contractor.

Drawings

The drawings included in the DCM are hereby incorporated into, and made a part of this Contract. The drawings will be revised as necessary to reflect the final design. New drawings shall be made part of the DCM by the Contractor. Site drawing will be updated by the Contractor to indicate the new installations and equipment modifications.

A. Bidder shall submit with his bid general arrangement drawings; descriptive information covering the design and site layout of the EPU cooling tower, inlet header piping, cold water outlet connections, and ancillary equipment; and an equipment list including manufacturer and model numbers.

B. After Contract award, Contractor shall submit five copies of each drawing and associated installation and removal instructions to Owner. Drawings and installation / removal instructions submitted to Owner shall be of a quality such that they will be capable of yielding hard copy reproductions with every line, character, and letter clearly legible and useable for further reproduction. Copies of the electronic files for all CAD drawings shall be submitted in AutoCAD Version 2006. Electronic copies of all project drawings shall be submitted to Owner.

C. All submittals of drawings and installation instructions shall include identifying information such as the Specific Plant Name, Specification number, drawing subject, and drawing number / revision, and the intended use, i.e. "For Construction" or "For Comments", or "For Reference", etc. The intended use shall also be specified on the transmittal letter.

D. All design drawings and data shall be submitted to Owner for review. Drawings and data submitted for review shall be complete in all respects and thoroughly checked by the Contractor. Drawings that are reviewed by Owner will be returned, properly noted with respect to their status for fabrication / construction; comments shall be incorporated and drawings and data shall be resubmitted to Owner.

E. All design drawings shall be stamped by a Professional Engineer registered in the State of Florida or by a Structural Engineer licensed in the State of Florida as appropriate.

F. All drawings prepared by the Contractor for this project shall become the property of Owner.

G. All drawings shall follow Owner's numbering scheme.

H. All equipment, pipes, valves, junction boxes shown on the drawings shall be labeled on the drawings with identification numbers supplied by Owner.

I. Drawings shall depict information appropriate to its division:

   1. Mechanical (including general arrangement, schematic, and physical drawings)

   2. Electrical / Instrumentation / Controls (including schematics, logic diagrams and physical drawings, P & ID)

   3. Civil / Structural

J. An original copy of all calculations needed for completion of the design shall be submitted to Owner for review. Any comments from Owner shall be resolved by the Contractor prior to final acceptance by Owner.

K. Vendor manuals for all supplied equipment shall be submitted to Owner "For Record". Five copies shall be submitted. Vendor manuals shall include a list of recommended preventive maintenance practices and a list of spare parts for the EPU cooling tower.

Exhibits

The Project's Phase 1 Alternatives analysis and related information will be made available to the Contractor as requested.

The Project's Phase 2 Conceptual Design Report and related information are available with this Contract.

Electrical Safety Requirements

1. All electrical equipment and industrial control panels delivered or brought onto the site in performance of this contract must be labeled by an OSHA approved nationally recognized testing laboratory (NRTL).
2. All electrical equipment installed as part of this contract must comply with the National Electric Code (NEC), NFPA 70 and where applicable ANSI C2 (NESC). The Buyer reserves the right to inspect electrical equipment and installations. Contractor is responsible for notifying Owner when installations are available for inspection.
3. Electric motors shall be labeled to be in accordance with NEMA MG-1 or listed by an OSHA approved NRTL.
4. Electrical equipment and devices for which there is a NRTL listing category must be Listed or Labeled by UL or another OSHA approved NRTL.
    a. The Canadian Standard Association (CSA) is not a recognized OSHA approved NRTL marking unless the label includes "US" or "NRTL".
    b. The European Union CE Markings Directive 93/68EEC is not a recognized OSHA approved NRTL marking.
    c. The International Electrotechnical Commission (IEC), IEC Standard 60529 for enclosures (IPxx), is not recognized as an acceptable OSHA approved NRTL label.

    Electrical equipment for which there is no listing category must be evaluated or tested using a method submitted to and approved by Owner prior to delivery of the equipment.

    Electrical equipment is also subject to the "Counterfeit Suspect Item Program."

Hoisting and Rigging Requirements

The Contractor will identify any special hoist or rigging requirements associated with the designed equipment.

Fire Prevention Requirements

No fire prevention system is expected to be required however; the final design will determine the need for fire prevention systems.

Acceptance Criteria

The DCM identifies the engineering and design functions that will need to be completed as a part of the work for this Contract. In addition, the final design, as required by the DCM, will conclude with providing a statement of Construction instructions. The final design documents (including: procurement specifications, Project drawings, and construction instructions) will be used by the Contractor to install the necessary Discharge Canal cooling equipment and support systems.

1.1.1 Acceptance Criteria for Task 1 - Update & Maintain the DCM as the engineering design & procurement specification generation is completed.

- The Contractor will provide a Design Construction Manual that contains a design basis section that:
    - A. Identifies the systems to be installed by the project,
    - B. Identifies the major components and equipment to be installed by this Project,
    - C. Provides the system requirements for each of the systems installed for the project,
    - D. Clearly identify the component design requirements for all the components installed for this Project.
    - E. The DCM will reflect the final design & as built conditions of the modified & newly constructed equipment & systems.

1.1.2 Acceptance Criteria for Task 2 – Procurement Specifications & Design Calculations

The Contractor will update the cooling tower specifications and update the other specifications as necessary. The specification will then be provided to Owner with proposed vendors as part of this effort. The acceptance criterion for this work is the development of specifications and support calculations that contain the correct design requirements for the equipment and systems.

1.1.3 Acceptance Criteria for Task 3 – Project Drawings

The Contractor will update the cooling tower drawings and generate new drawings as necessary to support the installation of the Project's equipment and systems. The drawings must be in enough detail to complete the construction as detailed in other sections of this document.

1.1.4 Acceptance Criteria for Task 4 – Construction Guidelines & Test Procedures

The Contractor will provide support information to clarify construction requirements. The Contractor will develop startup, functional testing, and performance test procedures to safely place the constructed equipment & systems into service. The Performance testing is to be completed by a third party.

1.1.5 Acceptance Criteria for Task 5a - The Contractor must use the conceptual design information in the DCM & related specification to complete the design and construction of a cooling tower that meets the design requirements provided in the DCM & section 3 of this document. The cooling tower must meet the performance requirements identified in Specification S2a as appropriate.

1.1.6 Not Used

1.1.7 Acceptance Criteria for Task 6a – The Contractor must use the conceptual design information in the DCM & Related specification to complete the design and related procurement specifications for the cooling tower basin on which the cooling tower is built and laydown/maintenance area around the cooling tower that meets all the requirements of section 3.0 of this document

- The cooling tower basin adequately supports and matches up with the cooling tower structure,
- The cooling tower basin has the capability to direct both cooling tower basin and percolation pond over flow to the Discharge Canal,
- The cooling tower basin & percolation pond over flow gravity drain into the Discharge Canal,
- The cooling tower basin allows for easy access and maintenance for marine growth removal,
- The maintenance area surrounding the cooling tower is 40' wide,
- The maintenance area will provide for traffic around the cooling tower when maintenance is not being performed.
- The design incorporates collection and handling of the storm water run-off from the area during construction and operation.

1.1.8 Acceptance Criteria for Task 7a - The acceptance criteria for this task is to design an intake structure that meets all the requirements of section 4.0, the DCM procurement specification, and:

- the intake structure will be located on the discharge canal just north of the cooling tower,
- the intake structure will have dual flow traveling screens to filter the water, one traveling screen for each lift pump, the traveling screen will have:
  - through screen velocity of < .5 feet per second flow at mean tide level,
  - Local and remote control room operation functions (primary operation will be from the remote operating console), in the CRS Main Control Room,

- Control room instrumentation that indicates operating status and differential screen pressure,
- Local instrumentation that includes operating status, operating current, and differential screen pressure, and visual observation window to view the traveling screen surface. (see DCM for additional requirements),

o the intake structure will have a dual flow traveling screen wash system,

- the screen wash system will be operated remotely with the capability of local operation,
- the screen wash system will have appropriate wash material handling equipment, and an appropriate wash water return configuration,
- screen wash system instrumentation will include pump operation status & spray header pressure,

o the intake structure will have 3 lift pumps, the lift pumps will:

- normally operate two pumps that have the capacity to provide the total amount of cooling towers flow,
- have one lift pump that can supply 100% backup capacity of one lift pump,
- one pump will have the capacity to recirculate the maximum amount of cooling water, 150,000 gpm,
- be normally operated from the control room but have remote operation capability for testing,
- Configured with instrumentation to remotely monitor bearing temperatures, motor temperature, motor current, and pump flow.

o the intake structure will have a weather enclosed and climate controlled housing for transformers & electrical switchgear and distribution panels, the enclosure will have breaker handling equipment, adequate lighting and room to properly maintain the switchgear.

1.1.9 Acceptance Criteria for Task 8a - The acceptance criteria for this task is to design a discharge structure that meet all the requirements of section 4.0, the DCM procurement specification, and:

o the discharge structure will be on the south side of the Discharge Canal

- return flow is to be directed such that the water will not be entrained with the HCT intake water

o The structure must be designed to return the water such that the water will not erode the canal at the point of discharge

Not Used

1.1.10 Acceptance Criteria for Task 10 - The acceptance criteria for this task is to provide procurement specifications for all the required material and develop a delivery schedule that coordinates the material deliveries such that there is no impact on the construction schedule or other CREC activities.

Not Used

PERSONNEL REQUIREMENTS

Training and Qualification

1.1.11 Contractor shall ensure that the Contractor's personnel meet and maintain the appropriate training, qualification and certification requirements. CREC site-specific training requirements to safely perform this work are identified below.

1.1.12 The following training is required:

- CREC general access training,
- Project specific indoctrination for safety and Project Management,
- Contractor job specific training (to be identified with the specialized tasks to be performed),
- Occupational Safety and Health Administration (OSHA) Training.

1.1.13 CREC required site training will be coordinated through the Designated Representative (DR). Advanced notice (48 hours) must be given the DR to arrange this training. Required OSHA, and Job Specific Training shall be provided by the Contractor.

1.1.14 The required training shall be completed prior to work.

1.1.15 The Contractor must meet the following minimum qualifications:

1. A professionally licensed engineer in the State of Florida is required to approve all of the final design documents to be used for construction.
2. Experience in the areas of general and cooling tower construction. The Contractor will have > 15 years experience with work on similar type, size, and scope projects.
3. The Contractor's Key personnel must be dedicated to this project and cannot be transferred without Owner's DR approval. The following are considered Key Contractor personnel.
   - The Contractor's Project Manager must have > 10 years experience managing work on similar type, size, and scope of projects.
   - The Contractor's Engineering Manager must have > 7 years experience managing work on similar type, size, and scope of projects.

Security and Badging Requirements

A. The Contractor shall obtain at the Contractor's expense, facility clearance and security badges for employees prior to obtaining access to the job site.

B. Contractor employees will be required to: submit to vehicle searches, obtain tool and equipment permits prior to entering and leaving restricted areas, and to maintain hard hat markings.

C. A minimum of 2 days advance notice is needed for visitor badging. CREC badges will be processed for those needing continuous access to the site. Processing for the site access badge is approximately 2 weeks.

Site Access and CREC Work Hours

A. Work will be done on an 8-9's schedule. The standard work day shall consist of nine (9) hours of work between 7:00 AM and 4:30 PM, with one-half hour designated as an unpaid period for lunch, which may be taken between the hours of 11:00 AM and 1:30 PM, but not to exceed five (5) hours from the start of the shift. An eight (8) hour work day is substituted on alternate working Fridays, and no work occurs on the alternate non-working Friday.

B. The Contractor will have access to the job site from notice to proceed through August 30, 2009.

ENVIRONMENTAL, SAFETY, HEALTH, AND QUALITY REQUIREMENTS

The Contractor shall perform work safely, in a manner that ensures adequate protection for employees, the public, and the environment, and shall be accountable for the safe performance of work. The Contractor shall comply with, and assist the Buyer in complying with Environmental, Safety, Health, and Quality (ESH&Q) requirements of all applicable laws, regulations and directives.

The Contractor shall flow down ESH&Q requirements to the lowest tier subcontractor performing work on the CREC site commensurate with the risk and complexity of the work.

The Contractor shall evaluate Subcontractors in accordance with Owner procedure SAF-SUBS-00041 or similar process approved by Owner

Integrated Environment, Safety and Health Management System (ISMS)

The Contractor shall exercise a degree of care commensurate with the work and the associated hazards. The Contractor shall ensure that management of ES&H functions and activities is an integral and visible part of the Contractor's work planning and execution processes. As a minimum, the Contractor shall:

- Thoroughly review the defined scope of work;
- Identify hazards and ES&H requirements;
- Analyze hazards and implement controls;
- Perform work within controls; and

- Provide feedback on adequacy of controls and continue to improve safety management.
- Continue pre-job safety evaluations and implement adequate controls for new hazards as they are identified.

The Contractor shall address how the five bulleted items above will be implemented in the Contractor's Project Specific Health & Safety Plan (PHASP).

Environmental Requirements

1.1.16 Environmental responsibility is a core value of Owner. We are committed to excellence in our environmental practices and performance. The company acknowledges 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.

1.1.17 In accordance with this policy the Contractor shall prepare an Environmental Execution Plan which describes how the Contractor will comply with Owner's core value of environmental responsibility. The plan must identify the organizational structure responsible for implementation of the plan; how the plan is to be administered; how environmental information and reporting to Owner will be handled; how worker awareness and environmental training will be implemented; and what additional documents and/or plans will be attached to or referenced by the plan. Examples of these additional documents include but are not limited to: Spill Prevention Control and Countermeasures (SPCC) Plan, Storm Water Pollution Prevention Plan (SWPPP), Waste Management Plan (for hazardous, industrial, and special wastes), and a chemical and petroleum product storage and inventory plan.

1.1.18 Contractor is strongly encouraged to incorporate Pollution Prevention practices in the selection of all chemical products required for the project. The contractor must obtain pre-approval for all chemicals brought on site in accordance with the Nuclear Generation procedure CHE-NGGC-0045, Chemical Control Program. The chemical approval process must start as soon as possible and the Contractor should keep in mind that a week approval process may be needed for typical evaluations.

1.1.19 Any RCRA hazardous waste created as the result of project activity become the responsibility of the site. The contractor will be responsible for properly containerizing, identifying, and labeling such waste in accordance with RCRA regulatory requirements. Through proper adherence to pollution prevention practices and chemical control procedures the generation of hazardous waste should be greatly minimized or eliminated. It is Owner's expectation that the Contractor will identify and estimate the quantity of hazardous waste anticipated to be generated during the duration of the Project. Records of all hazardous and special waste (e.g., used oil) activities shall be maintained and provided to Owner at least monthly, and/or as requested.

1.1.20 Owner is responsible for obtaining all environmental regulatory permits necessary for construction of the project including: PSD Construction permit, Environmental Resource Permit, Florida NPDES storm water permit for construction activity, and Florida Industrial Wastewater NPDES discharge permit. The Contractor is responsible to provide the necessary engineering to support submittal of the permits in a timely manner that supports the Project's schedule.

1.1.21 The Contractor must incorporate the requirements of the Crystal River Site Manatee Protection Plan into any "in-water" work conducted in the site discharge canal. The protection is for work completed during the period November 15 through March 31.

Safety Requirements

A. The Contractor is required to submit a Project Specific Health & Safety Plan that identifies the potential hazards that may be encountered in completing this work scope. The PHASP procedures and processes will address the Owner procedures were applicable. For example the Contractor's Lock Out/ Tag Out process must be consistent with Owner requirements. The Contractor will revise the PHASP as necessary to include new hazards when they are identified. As applicable, the following topics will be covered in the PSHASP and comply with applicable OSHA standards.

a. INTRODUCTION AND TABLE OF CONTENTS
b. GLOSSARY
c. PROGRAM GENERAL REQUIREMENTS
d. RESPONSIBILITY, AUTHORITY, AND ACCOUNTABILITY
e. SAFETY RELATED DISCIPLINE
f. TRAVEL SAFETY
g. OFFICE SAFETY
h. EMERGENCY PREPAREDNESS
i. SAFETY AND HEALTH COMPLIANCE INSPECTION AND MANAGEMENT WALKTHROUGHS
j. ACCIDENT PREVENTION TRAINING AND EDUCATION
k. PREJOB SAFETY PLANNING
l. DRUG-FREE WORKPLACE/FITNESS-FOR-DUTY PROGRAM
m. EVENT INVESTIGATING AND REPORTING
n. CLASSIFYING AND RECORDING INJURY/ILLNESS
o. WORK HOUR CONTROL/WORKING ALONE
p. WORK RELEASE CONTROL
q. PERSONAL PROTECTIVE EQUIPMENT
r. FALL PROTECTION
s. HAZARDOUS MATERIALS AND FLAMMABLE / COMBUSTIBLE LIQUIDS
t. FIRE PREVENTION AND PROTECTION
u. HOUSEKEEPING
v. MOTORIZED EQUIPMENT PREOPERATIONAL AND PERIODIC INSPECTION
w. HOISTING AND RIGGING
x. ELEVATING WORK PLATFORMS AND AERIAL LIFTS

y. SIGNS, SIGNALS, AND BARRIERS

z. SAFETY SHOWERS AND EYEWASHES

aa. PORTABLE LADDERS

bb. SCAFFOLDS

cc. COMPRESSED GAS OPERATIONS

dd. MATERIAL HANDLING AND STORAGE

ee. MACHINERY AND MACHINE GUARDING

ff. HAND AND PORTABLE POWER TOOLS

gg. WELDING SAFETY

hh. CONTROLLING HOT WORK

ii. ELECTRICAL WORK SAFETY

jj. ELECTRICAL INSTALLATION SAFETY

kk. EXCAVATION, TRENCHING, AND SHORING

ll. CONCRETE AND MASONRY CONSTRUCTION

mm. DEMOLITION

nn. SAFETY COLOR CODING FOR MARKING PHYSICAL HAZARDS

oo. LOCKOUT/TAGOUT PROGRAM

pp. CONTROLLING ORGANIZATION'S CONTROL OF HAZARDOUS ENERGY

qq. STEEL ERECTION

rr. CONSTRUCTION AND MAINTENANCE EATING AND SANITARY FACILITIES

ss. WORKSITE FIRST AID

tt. FLUSHING AND PRESSURE TESTING

uu. INDUSTRIAL HYGIENE PROGRAM REQUIREMENTS

vv. HEARING PROTECTION

ww. HEAT STRESS PROGRAM

xx. LEAD CONTROL

yy. OCCUPATIONAL MEDICAL PROGRAM

zz. HAZARD COMMUNICATION

aaa. RESPIRATORY PROTECTION

bbb. INFECTIOUS DISEASE (BLOODBORNE PATHOGENS)

ccc. CONFINED SPACE ENTRY

ddd. OCCUPATIONAL ERGONOMICS

B. The Contractor's PSHASP must be approved by Owner prior to starting the work covered by that practice.

C. Chemical Management. If hazardous materials and/or chemicals (such as cements, grouts, lubricants, glues, adhesives, explosives, paints, solvents, cleaners and temporary fuel storage containers) will be brought on-site by the contractor in the performance of the work, these items will need to be tracked through the Owner Chemical Management Program using Attachment 2 of CHE-NGGC-0045, NGG – Chemical Control Program.

D. If the Contractor has more than one employee working on site in performance of this contract, the Contractor will identify a member of its staff as its "Designated Safety Representative." This individual must have the authority, responsibility and knowledge to identify and correct any unforeseen hazardous or unsafe conditions, acts or instances of noncompliance.

Quality Assurance and Control

A. Contractor shall be responsible for performing quality workmanship and shall conduct the quality control measures necessary to ensure work conforms to drawings and specifications.

B. Plans, procedures, and engineering documentation shall be controlled in accordance with the Contractor's and Lower-tier Subcontractor's Quality Assurance Program which may be reviewed by Owner.

C. Third party as referred in this document shall be a lower-tier subcontractor qualified per ASTM E-329, Agencies Engaged in the Testing and / or Inspection of Materials Used in Construction.

D. Owner reserves the right to make inspections at any time at the source of supply of materials.

E. All items and processes are subject to review, inspection or surveillance by Owner at the contractor's facility, or any lower-tier subcontractor's facility.

F. Equipment requiring calibration shall be periodically calibrated to assure reliable results.

G. Contractor shall be responsible for the performance of all inspection and testing activities as specified in the Contractor's submittal "Quality Assurance Inspection Plan," provided to Owner for approval within 30 days of contract award.

Quality Assurance/Inspection Requirements

A. Quality Assurance Program Submittal and Pre-Award Survey

The Contractor shall submit the quality assurance program requirements that are applicable to the implementation of the designed work. These requirements shall be in a format that can be included in the construction contract for this work.If the Contractor's manual has been previously approved by the Buyer, the manual shall be updated to make it current and resubmitted to Owner with the proposal. If the manual has not changed since its previous approval by Owner, a statement to this effect shall be submitted with the proposal. Owner shall evaluate the Contractor's Quality Assurance program prior to contract award. This evaluation may include a survey of quality program implementation at the Contractor's facilities. If a program change is required, it will be identified to the Contractor prior to contract award. A deficient or inadequate program may be used as the basis to deny award of this contract.

The selected Engineering Contractor will identify the necessary level of quality control during the engineering design process and state QA/QC requirements on the applicable design and procurement documents. The following requirements will apply as identified during the engineering design process.

B. Supplier Quality Program Evaluation

When subcontracting any portion of this Purchase Order/Contract Order, the Supplier is required to invoke the applicable quality assurance program requirements on the subcontractor.

Owner reserves the right to verify the quality of work at the Supplier's facility, including any subcontractor's facility. Access to a subcontractor's facility shall be requested through the Supplier and verification may be performed jointly with the Supplier.

The Supplier shall, during the performance of this Purchase Order/Contract Order, submit proposed changes to the quality assurance program to the Contractor & Owner for review prior to implementation.

C. Nonconformance Documentation and Reporting

All nonconformances identified at the Supplier's facility with a proposed disposition of "Accept" or "Repair" shall be approved by the Buyer before any corrective action is taken by the Supplier on the nonconformance.

Accept: A disposition that a nonconforming item will satisfactorily perform its intended function without repair or rework.

Repair: A disposition requiring the processing of a nonconforming item so that its characteristics meet the requirements listed in the disposition statement of the nonconformance report.

Nonconformance shall be documented by the Supplier on the Supplier's nonconformance form or on an Engineering Procurement Waiver, which is provided by the Buyer. After documenting the nonconformance, disposition and technical justification, the form/waiver shall be forwarded to the Buyer.

After the recommended disposition has been evaluated by the Contractor & Owner, the form/waiver shall be returned to the Supplier with a disposition of approval or rejection. The Supplier may take corrective action on the nonconformance only after the form/waiver is approved.

The approved Engineering Procurement Waiver or Supplier's nonconformance form shall be shipped with the affected item.

D. Certified Welds & Inspectors

The Contractor is required to identify the weld and weld inspection requirements for this design. The weld requirements will be included on the appropriate drawings and in the construction guidelines.

E. Identification of items with Part number/Model Number

The Contractor is required to provide procurement and construction requirements to verify material by part number. The requirements will be in the procurement specifications and construction guidelines. For example - All items shall be identified with the part number/model number. Identification shall be on the item or the package containing the item. When the identification is on the item, such marking shall not impair the service of the item or violate dimensional, chemical, or physical requirements.

F. Identification of Items with Product Data Sheet

The Contractor is required to provide procurement and construction requirements for the supplier to submit a legible copy of the product data sheet (e.g., drawing, catalog page, brochure) that provides adequate information to enable the Buyer to verify the form and function of the article procured. One copy of the documentation, unless otherwise specified, shall accompany the applicable item(s) shipped. The requirements will be in the procurement specifications and construction guidelines.

G. Identification of Items

The Contractor is required to provide procurement and construction requirements for the items to be identified with the part number/model number. Identification shall be on the item or the package containing the item. When the identification is on the item, such marking shall not impair the service of the item or violate dimensional, chemical, or physical requirements. The requirements will be in the procurement specifications and construction guidelines.

The Supplier shall submit a legible copy of the product data sheet (e.g., drawing, catalog page, brochure) that provides adequate information to enable the Buyer to verify the form and function of the articles procured.

One copy of the documentation, unless otherwise specified, shall accompany the applicable item(s) shipped.

H. Identification and Traceability of Items

Where necessary the requirements for material traceability will be incorporated into the procurement specifications and construction guidelines. For example: All items shall be identified with the part, heat, batch, or serial number and the Purchase Order and line item number. Identification shall be on the item or the package containing the item. Where identification is on the item, such markings shall not impair the service of the item or violate dimensional, chemical, or physical requirements.

I. Identification of Age Control Items

The requirements for identification of age control will be in the procurement specifications and construction guidelines. For example: The Supplier shall identify each item, assembly, package, container, or material, having limited shelf life, with the cure date or date of manufacture and the expiration date. The Supplier shall specify any storage temperatures, humidity and environmental conditions which should be maintained. Material shall NOT be furnished having less than 75 percent of total shelf life available at time of shipment.

J. Liquid Penetrant Material Certification

The requirements for liquid penetrant material certification will be in the procurement specifications and construction guidelines. For example: A certification of contaminant content shall be furnished for each batch number of penetrant, cleaner, developer, and emulsifier provided. The certification shall include the test results which meet the requirements of ASME Section V, Article 6, and the latest mandatory addenda or Purchase Order/Contract Order specified addenda. All materials and reports are subject to review and acceptance by the Buyer.

K. Certified Material Test Report

The requirements for certified material test reports will be in the procurement specifications and construction guidelines. For example: The Certified Material Test Report (CMTR) shall include actual results of all chemical analysis, tests, examinations, and treatments required by the material specification and this Purchase Order/Contract order. The CMTR shall be legible, reference applicable specification number and year of edition, and be traceable to the material furnished by heat or lot number. All reports are subject to review and acceptance by the Buyer.

The report(s) shall contain the Purchase Order/Contract Order number and a description of the item to which the report applies. The report shall be signed by an authorized representative of the Company.

One copy of the documentation, unless otherwise specified, shall accompany the applicable item(s) shipped.

L. Inspection and Test Report

The requirements for inspection and test reports will be in the procurement specifications and construction guidelines. For example: The Supplier shall submit legible, reproducible copies of Inspection/Test Reports.

The report(s) shall include the following:

1. Identification of the applicable inspection and/or test procedure utilized.
2. Resulting data for all characteristics evaluated, as required by the governing inspection/test procedure.
3. Traceability to the item inspected/tested, (i.e., serial number, part number, lot number, etc.).

4. Signature of the Supplier's authorized representative or agency which performed the inspections/tests.

One copy of the documentation, unless otherwise specified, shall accompany the applicable item(s) shipped.

M. Flame Test Report

The requirements for flame test reports will be in the applicable procurement specifications and construction guidelines. For example: A flame test report shall be submitted. The report shall include the following:

1. Test procedure identification.
2. Resulting data as required by IEEE-383.
3. Traceability to the material tested (i.e., batch number, heat number, lot number).
4. Signature of the authorized representative or agency performing the tests. Reports shall also reference the Purchase Order/Contract Order number.

One copy of the documentation, unless otherwise specified, shall accompany the applicable item(s) shipped.

N. Calibration Report

The requirements for calibration reports will be in the procurement specifications and construction guidelines. For example: Certification stating the equipment furnished to the Purchase Order/Contract Order requirements has been calibrated utilizing standards whose calibration is traceable to the National Institute of Standards and Technology or other documented evidence must be submitted stating the basis of the calibration. In addition, the Supplier shall submit a report of actual calibration results. The report shall be identifiable to the acceptance criteria of the items submitted and shall meet Purchase Order/Contract Order requirements. The report shall contain the signature of the authorized representative of the agency verifying compliance.

One copy of the documentation, unless otherwise specified, shall accompany the applicable item(s) shipped.

O. Certification of Calibration

The requirements for certification of calibration records will be in the procurement specifications and construction guidelines. For example: The Supplier shall submit legible, reproducible copies of Certificates of Calibration, which are traceable to the National Institute of Standards and Technology, for each article ordered. Each certificate shall be identified with:

1. The Buyer's Purchase Order/Contract Order number.
2. Identification of the article to which the certificate applies.
3. The standards used for calibration. Each calibration certificate shall be signed by the Supplier's representative that is responsible for the calibration to attest to its authenticity.

One copy of the documentation, unless otherwise specified, shall accompany the applicable item(s) shipped.

P. Repair and Calibration Services

The requirements for calibration and repair will be in the procurement specifications and construction guidelines. For example: When repair and calibration services are required, the Supplier shall perform the repairs in accordance with the manufacturer's instructions. The report of calibration shall include:

1. Actual calibration or test data
2. The as-found data or condition
3. As-left data (after repair and calibration, before leaving the Lab) if different than the as-found data
4. The scope and description of repairs completed or attempted, if applicable.
5. The instrument identification or serial number

The report shall be signed by the Supplier's authorized representative.

One copy of the documentation, unless otherwise specified, shall accompany the applicable item(s) shipped.

Q. Supplier Furnished Items

Suppliers shall obtain the items on this Purchase Order/Contract Order directly from the original manufacturer. The supplier shall provide legible and reproducible documentation, with the delivery, that provides objective evidence that the items were provided by the original manufacturer. These may include the Purchase Order/Contract Order to the original manufacturer, shipping documentation, or manufacturer invoice; each of which identifies the items obtained from the original manufacturer.

One copy of the documentation, unless otherwise specified, shall accompany the applicable item(s) shipped.

R. Control of Graded Fasteners

The requirements for control of graded fasteners will be in the procurement specifications and construction guidelines. For example: The provisions stated below are the minimum requirements for high strength graded fasteners produced in compliance with national consensus standards (e.g., SAE, ASTM, ASME).

1. Fasteners shall exhibit grade marks and manufacturer's identification symbols (headmarks) as required in the specifications referenced in the Purchase Order/Contract Order.

2. Any fasteners supplied with headmarks matching those displayed on the attached Suspect/Counterfeit Fastener Headmark list, or facsimiles thereof, shall be deemed to be unacceptable under the terms of this Purchase Order/Contract Order.

3. When requested by the Buyer, the Supplier shall provide a legible and reproducible copy of the manufacturer's Certified Material Test Reports (CMTR). These CMTRs shall report the values of the actual chemical and physical tests performed on the represented fastener lot/material heat. Fastener packaging/labeling shall be traceable by lot number or other positive means to the CMTRs.

4. Fasteners shall be inspected to verify compliance with the Purchase Order/Contract Order requirements. Additionally, fasteners may also be subjected to destructive testing.
5. When requested by the Buyer, the Supplier shall provide a Certificate of Conformance which must certify conformance and traceability of supplied materials to the subject Purchase Order/Contract Order. The document must be legible and reproducible.

S. Procurement of Potentially Suspect or Counterfeit Items

The requirements for procurement of suspect or counterfeit items will be in the procurement specifications and construction guidelines. For example: Supplier shall warrant that "all items furnished under this Purchase Order/Contract Order are genuine (i.e., not counterfeit) and match the quality, test reports, markings and/or fitness for use required by the Purchase Order/Contract Order".

The statement shall be on supplier letterhead and signed by an authorized agent of the supplier.

T. Certificate of Conformance

The requirements for certificate of conformance will be in the applicable procurement specifications and construction guidelines. For example: The Supplier/Manufacturer shall provide a legible/reproducible Certification of Conformance. Supplier's/Manufacturer's authorized representative responsible for quality shall sign the Certification of Conformance.

This Certification of Conformance shall, as a minimum:

1. Identify the appropriate Purchase Order/Contract Order number under which the material, equipment, item or service is being supplied.
2. Supplier/Manufacturer shall warrant that all items furnished meet the requirements of the Purchase Order/Contract Order.

One copy of the documentation, unless otherwise specified, shall accompany the applicable item shipped. For subsequent shipments on this Purchase Order/Contract order, reference may be made to documentation provided with earlier shipments, instead of duplicating such documentation.

U. Recommended Spare Parts Listing

The Contractor will require that the vendors submit, with or prior to item shipment, a recommended spare parts list. The list shall provide the name and address of the original supplier of the replacement part, and the part's drawings, specification, or catalog identity including applicable change or revision information.

Software Products and/or Services Where Software is Used

A. Design/Development of Custom Software

The Contractor will provide monitoring and controls as identified in this document. If new software is developed by the Contractor the following requirements apply:

1. Based on requirements provided to the Contractor, the Contractor shall submit the following information for Owner review for software development:
   - Description of the major components of the software design as they relate to the software requirements.
   - Technical description of the software with respect to the theoretical basis, mathematical model, control flow, data flow, control logic, and data structure.
   - Description of allowable or prescribed ranges for inputs and outputs
   - List of integration points (interfaces)
   - Data model
   - Hardware/Software configuration
   - Design described in a manner that can be translated into code
   - Computer program listing(s)
2. The Contractor shall develop and submit to Owner a Software Management Plan and procedures that describe their computer software development, test, and configuration management process. The plan shall, as a minimum, contain the following:
   - Identify the software products covered by the Software Management Plan.
   - Describe Contractor organizations responsible for performing the work and achieving software quality and their tasks and responsibilities. Clearly identify any Owner interfaces, and requirements.
   - Describe the configuration management methodology.
   - Describe the types of documentation to be prepared, reviewed, and maintained during software design, development, implementation, test and use.
   - Describe the process for reporting and documenting software problems/errors, evaluating the impacts of problems on previous measurements and uses, and determining the appropriate corrective action(s).

- Identify standards, conventions, techniques, or methodologies that guide the software development, as well as the methods used to ensure implementation of requirements.
- Provide procedure(s) for establishing and maintaining the integrity of data, embodied mathematical models, and output files.
- Specify methods to verify and validate developed, acquired, or modified software.

3. A copy of the original program code shall be maintained and submitted to Owner as a Submittal.
4. Configuration management during the development and/or modification of computer software shall be identified and documented.
    - Uniquely identify each configuration item (e.g., screens, reports, tables, documents, etc.)
    - Configuration status accounting information shall be documented and identify the approved configuration, status of proposed changes to the configuration, status of approved changes, and information to support the functions of the configuration identification, and configuration control.
    - Identify changes to configuration items by revisions. Change control processes shall provide objective evidence of evaluation, coordination, and approval of changes prior to implementation of the change.
    - Provide the ability to uniquely identify each configuration of the revised software available for use.
5. Verification and Validation activities shall be performed to ensure software requirements are correctly specified and implemented in the design criteria, test documentation, and completed code. Such verification shall ensure traceability of test results to specified functional requirement.
    - Software testing shall include development testing, validation reviews, verification testing when appropriate.
    - Software shall be acceptance tested when installed, after changes, and periodically during use, as appropriate during the contract.
    - Design verification shall be completed and design outputs released for use, before relying on structures, systems, components, or computer programs to perform their function and before installation become irreversible.
    - The monitoring and control functions will be tested without impacting equipment operation as part of the verification process and prior to equipment operation.
6. The Contractor will supply standard support documents for software products. Standard product deliverables for custom software include: Requirements Document, System Design Description, Test Documents (plan, test cases, and test

results), Installation/Operations manual, Installation Plan/Checkout, Acceptance Test Report, and User Documentation.

7. The Contractor will provide for installation assistance, checkout, and training of operators and users.

8. Acceptance of the computer software and hardware is based on the Contractor providing a functioning monitoring and control system that is integrated into the existing Owner system.

B. Design of Hardware with Software Instrumentation and Controls (e.g., PLCs)

1. Based on requirements provided to the Contractor, the Contractor shall submit the following information for Owner review for system development:

   - Description of the major components of the software design as they relate to the system requirements.
   - Technical description of the hardware/software with respect to the theoretical basis, mathematical model, control flow, data flow, control logic, and data structure.
   - Description of allowable or prescribed ranges for inputs and outputs
   - List of integration points (interfaces)
   - Data model, associated drawings, diagrams, equipments lists, etc.
   - Hardware/Software configuration
   - Design described in a manner that can be translated into code
   - Computer program listing(s)

2. The Contractor shall develop and submit to Owner a System Management Plan and procedures that describe their computer software development, test, and configuration management process. The plan shall, as a minimum, contain the following:

   - Identify the software products covered by the System Management Plan.
   - Describe Contractor organizations responsible for performing the work and achieving software quality and their tasks and responsibilities. Clearly identify any Owner interfaces, and requirements.
   - Describe the configuration management methodology.
   - Describe the types of documentation to be prepared, reviewed, and maintained during system design, development, implementation, test and use.
   - Describe the process for reporting and documenting software problems/errors, evaluating the impacts of problems on previous measurements and uses, and determining the appropriate corrective action(s).

- Identify standards, conventions, techniques, or methodologies that guide the software development, as well as the methods used to ensure implementation of requirements.
- Provide procedure(s) for establishing and maintaining the integrity of data, embodied mathematical models, and output files.
- Specify methods to verify and validate developed, acquired or modified software.

3. A copy of the original program code shall be maintained and submitted to Owner as a Submittal.
4. Configuration management during the development and/or modification of computer software shall be identified and documented.
    - Uniquely identify each configuration item (e.g., screens, reports, tables, documents, etc.)
    - Configuration status accounting information shall be documented and identify the approved configuration, status of proposed changes to the configuration, status of approved changes, and information to support the functions of the configuration identification, and configuration control.
    - Identify changes to configuration items by revisions. Change control processes shall provide objective evidence of evaluation, coordination, and approval of changes prior to implementation of the change.
    - Provide the ability to uniquely identify each configuration of the revised software available for use.
5. Verification and Validation activities shall be performed to ensure software requirements are correctly specified and implemented in the design criteria, test documentation, and completed code. Such verification shall ensure traceability of test results to specified functional requirement.
    - Software testing shall include development testing, validation reviews, verification testing when appropriate.
    - Software shall be acceptance tested when installed, after changes, and periodically during use, as appropriate during the contract.
    - Design verification shall be completed and design outputs released for use, before relying on structures, systems, components, or computer programs to perform their function and before installation become irreversible.
    - List expected validation tests, hardware integration tests, and in-use tests to be conducted and the controls to be applied. A validation and verification report shall be submitted to Owner for approval. It will be used in conjunction with Owner acceptance testing/criteria to document successful completion of the contract.
6. Standard support documents are required for hardware/software products. It must be determined as to which Owner or the Contractor will provide. Standard product

deliverables for hardware/software systems include: Requirements Document, System Design Description, Test Documents (plan, test cases, and test results), Installation/Operations manual, Installation Plan/Checkout, Acceptance Test Report, and User Documentation.

7. Contractor must provide installation assistance, checkout, and training of operators and users.

8. Acceptance of the computer software and hardware is based on the Contractor providing a functioning monitoring and control system that is integrated into the existing Owner system.

MEETINGS, SUBMITTALS, WORK & PROJECT CONTROL REQUIREMENTS

Meetings

A. After contract award, the contractor shall participate in a Project Kickoff Meeting to be held at CREC. The time, date, and agenda for the meeting will be provided to the Contractor upon contract award. The kick-off meeting will be within 10 days of contract award.

B. The person or persons designated by the Contractor to attend all meetings shall have all required authority to make decisions and commit Contractor to technical decisions made during meetings.

C. Weekly Progress Meetings

   1. At the weekly progress meeting, Contractor shall submit a written report showing actual man-hours expended versus planned and scheduled progress versus actual progress giving details of Work completed in relation to the approved schedule, together with a two (2) week "look ahead" which provides details of how the Work will be completed.

   2. Contractor shall attend a weekly coordination meeting together with various contractors at the jobsite. Attendance can be by telecommunication if approved by PEF Designated Representative.

H. Pre-job / Weekly Safety Meeting

   1. All Contractor employees shall attend indoctrination and orientation prior to commencing work at the jobsite. This pre-job meeting will be held at CREC as set up by the Contractor.

   2. Additional weekly safety meetings for all craft employees shall be held during active work.

I. Other Meetings

   1. Contractor participation in certain additional activities shall also be required. These activities shall include, but are not limited to:

      a. Indoctrination and orientation of all Contractor's employees prior to commencing work at the jobsite (This includes the entire labor force and all new hires). The meeting will last approximately 3 hours.

2. Weekly gang box safety meetings organized and conducted by Contractor and attended by all of Contractor's employees involved in the field work. Contractor shall be responsible for arranging and conducting these meetings with its craft employees. The meetings should last approximately 1 hour.

Additional Detail

1. The Contractor is responsible to coordinate and conduct all the Project interface meetings discussed in this section. The Contractor will:

   - Consult with the Project's Designated Representative in developing the meeting agendas. The Contractor will provide an agenda to the meeting attendees for each meeting a minimum of 24 hours in advance to the meeting.
   - Start each meeting with a safety topic discussion. This discussion is not meant to last more than 5-10 minutes.
   - The Contractor will take meeting minutes and distribute the meeting minutes for review within 2 days of the meeting. After allowing 1 day for comments the meeting minutes will be issued as final within 1 week of the meeting.
   - The Contractor will maintain a list of Owner and associated Project personnel for meeting minute distribution. The list is to be approved by the Project's Designated Representative.

a. The Contractor will participate in a Kick off meeting within 10 days of the Notice to Proceed is issued by Owner's Contract Administrator.

b. The Kick-off Meeting will be at CREC and include:

   - Safety & human performance topics
   - Introductions
   - Owner presentation -- ~ 2 hour
     - Project & CREC Site Safety Expectations
     - Contract overview and deliverables
     - Contractor communications and progress reporting
     - Site access and training
   - Contractor's overview of the Project organization including a discussion of how the Contractor will interface with Owner Personnel.
   - Contractor's safety culture
   - Contractor's Project Organization & Key personnel
   - Contractor's on site work
   - Contractor's approach to contracted work, including engineering & procurement specifications,
   - Contractor's use of design criteria manual

- Contracted deliverables and milestones
- Project schedule – Level III
- Contractor's cost control & earned value system

2. Weekly Status Meetings will be approx. 1 hour, set up and conducted by the Contractor. The meeting will be setup at the same time and location every week. The meeting will consist of:
   - Safety & human performance topics
   - Earned value status (cost vs. schedule)
   - Projected estimate at completion cost (EAC)
   - Accomplishments/Milestones
   - Issues/Request for Information forms and status of open requests
   - Scheduled accomplishments for next week
   - Number of personnel working on the project (last week and next week)
   - 4-week look ahead activities and support requirements
   - General discussion – Q&A
3. Monthly cost accounting status meetings will consist of weekly meeting content plus end of month accruals.
4. The Contractor will conduct daily pre-job safety briefings. The briefing will at a minimum include:
   - Review of yesterday's activities
   - Overview of planned activities for the day and required PPE
   - Required materials
   - Potential safety issues & concerns
   - Activities being completed by others in nearby areas
   - Support requirements
   - Expected work site conditions
   - Q&A
5. Periodically during management oversight observations.
   - The Contractor will have periodic reviews and audits. These reviews will require the Contractor's support.

Request for Information

The Request for Information Form (RFI) will be used to document all formal requests for information or direction. The form is structured to ensure that if the required direction or the request is acted on in a timely manner. In addition, the RFI will ensure that potential impact on the project's cost, schedule, or scope is properly identified and managed.

The Contractor will set up and maintain the RFI log. The Contractor is responsible for the distribution of the RFIs.

Submittals

A. The Contractor's submittals shall be submitted to Owner in accordance with the instructions contained in the Attachment A, Submittal Register.

B. The Contractor submittals identified in this Contract and summarized on the Submittal Register shall be submitted by the Contractor using the supplied document submittal form.

Work Control Requirements

A. Contractor Work Control Processes

The Contractor shall submit its proposed Work Control Processes for approval within 30 days of contract notice to proceed (NTP). The work control process must cover all field activities including engineering walkdowns. The work process should identify:

- The organization that will be established to control the work,
- State the organizational responsibilities,
- Identify the measures that will be implemented to maintain a safe work environment,
- Housekeeping,
- Traffic control,
- Establishing and removing work boundaries,
- Interface with Owner support and coordination of work (Owner notification of work activities),
- Personal Protection Equipment identification and enforcement,
- Work document development, control, and approval,
- Conduct of pre-job and safety meetings,
- Control of chemicals,
- Work coordination,
- And, incorporation of environmental permit information into the work process.

DELIVERABLES, MILESTONES AND PERFORMANCE SCHEDULE

Deliverables

The Contractor deliverables are as follows:

- Project Quality Assurance/Control Plan
- Project Safety and Health Plan

- o Environmental Compliance Plan
- o Engineering 30% design package
- o Engineering 70% design package
- o Final design package (Design Criteria Manual), including:
  - o Completed Procurement Specifications
  - Engineering calculations
  - Engineered drawings
  - Construction instructions
  - Testing requirements and test procedures
- o Work control process plan
- o Construction Estimate
- o Final design Criteria Manual, (ready for construction).

Milestones

The Project Milestones will be identified after contract award. However the Project engineering will be complete on or before August 30, 2009.

Performance Schedule

The Contractor shall submit a draft performance schedule for this work with the Contractor's bid package. The schedule will be in enough detail to demonstrate the Contractor understands the scope of work as detailed in this SOW. The schedule will identify major milestones and complete all the work on or before August 30, 2009.

The schedule should start from NTP and is expected to include such items as:

- o Mobilization (engineering and construction),
- o Identification of specific engineering work packages development, review, and approval,
- o Procurement specification review, modification, and issue,
- o Equipment and material delivery schedule,
- o Equipment manufacture durations and shop fabrication,
- o Start and completion of different segments of work,
- o Pre-construction work,

Contractor shall submit a detailed performance schedule for this work within 15 days of award. The schedule shall be in Primavera or compatible format.

Contractor shall provide a two-week "look ahead" schedule, updated weekly, one day prior to each Weekly Progress Meeting.

The contractor will update the estimated Project schedule at the end of the design work. This updated schedule will estimate the remaining Project's duration.

ATTACHMENT A

SUBMITTAL REGISTER

Submittal Register Definitions

1. Numerical submittal sequence number: Example: 1, 2, 3, 4, ... (or organized by topics and project assigned coding structure)

2. Number and Type of Copies (No / Type Copies): Example: E (Electronic only), 6 (Six Hard Copies), 1, E (One Hard Copy, and Electronic)

3. Submittal Type:

APP =	For Approval (the submittal is provided with the intent that Owner will review and approve the submittal prior to the contractor proceeding with work).
ACC =	For Acceptance (the submittal is provided for information with the intent that Owner will accept the submittal)
AFW =	Approval for Work (the submittal is provided with the intent that Owner authorizes work to be performed to the submittal)

4. Format: this describes the type of submittal required:

DWG	An AutoCAD drawing using the CREC standard formatting
MFC	Microsoft Format Compatible application (Word, Excel, Access, PowerPoint)
P3	A Primavera Project Planner schedule
GEN	General or Open Format/Media
PDF	Adobe Acrobat (Portable Document Format)

5. Document Family:

CON	Construction
ENG	Engineering
FAB	Fabrication
H&S	Health and Safety
PRO	Procurement
QAC	Quality
PROJ	Project
VI	Vendor Information
OTHER	Other

6. Description / Document Title: Title or general description of the document.

7. Submittal Date: Actual date or number of Calendar Days before or after a milestone that a submittal is due from the Contractor: Example: June 1, 2005 or CD + 60 [60 days after Conceptual Design Complete]

CD	Conceptual Design Complete
PD	Preliminary Design Complete
FD	Final Design Complete
M	Mobilization
SC	Start of Construction
EC	End of Construction
A	Date of Award

8. Buyer Review Time (Work Days): Example: 3 Days

9. Contract Reference: Cross reference to the Contract requirement that defines this submittal: Example: SOW 3.1.2.

Submittal Register:

The Contractor shall meet the required schedule and provide the documents specified in accordance with the following submittals.

Contract Number and Name						Revision		
1 Submittal No.	2 Revision Number	3 Submittal Type	4 Format & Type	5 Document Family(ies)	6 Description/ Document Title	7 Submittal Date (Calendar Days)	8 Owner Review Time (Work Days)	9 Contract Reference
1	1	APP	PDF	OTHER	Site Access Forms	Prior to access	48 hrs.	2.4
2	1	ACC	GEN	PRO	Earned Value Information	Weekly	2	4.6 4
3	1	ACC	PDF	H&S	Corporate Health & Safety Plan	With Bid	7	4.7
4	1	APP	MFC	H&S	Project specific HASP	After Award	7	4.7, 6.2
5	1	APP	MFC	QAC	Quality Assurance Inspection (Control) Plan	30 days after award	7	6.3 G
6	1	ACC	PDF	QAC	Quality Assurance Program Manual	With Bid	7	6.4 A
7	1	APP	MFC	QAC	Software Management Plan		7	6.4 E
8	1	ACC	MFC	ENG	Work Control Process	30 after NTP	7	6.4 O
9	1	ACC	P3	ENG	Draft Performance Schedule	With Bid	7	6.5 A
10	1	APP	P3	ENG	Detailed Performance Schedule	15 days after Contract Award	7	7.1 C

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Contract Number and Name:							Revision:	
1 Submittal No.	2 No. of Copies	3 Submittal Type	4 Format	5 Document Type(s)	6 Description / Document Title	7 Submittal Date (Calendar Days)	8 Buyer Review Time (Work Days)	9 Contract Reference
11	1	APP	GEN	OTHER	Proposed temporary Facilities	Prior to Mob.	5	A 3.0 C
12	5	APP	MFC	ENG	30% Design Review	CD	7	8.1
13	5	APP	MFC	ENG	70% Design Review	CD	7	8.1
14	10	APP	MFC	ENG	Completed Design	FD	7	8.1
	5	APP	MFC	ENG	Environmental Compliance Plan	FD	7	8.1
16	5	APP	GEN	ENG	Estimate for Construction	FD	3	8.1

ATTACHMENT B

SITE COORDINATION REQUIREMENTS, FACILITIES AND UTILITIES

- **General**

A. CREC Survey bench marks are available for setting out the Work. The Contractor is responsible to complete the necessary surveys from the CREC benchmarks to support the Work. The Project drawings will use the CREC site coordinates and elevation.

B. The Contractor must establish location and extent of service lines in area of Work and notify Owner of findings. The Contractor will identify the utilities and service lines (including abandoned lines) in the design package. The Contractor will take all precautions to ensure that there are no unknown services in the work area.

C. Where unknown services are encountered, immediately advise Owner and confirm findings in writing. Identify the lines in the construction guidelines.

D. Record locations, including elevations, of maintained, rerouted and abandoned service(s). Provide these locations to Owner. Owner will provide direction on relocating the service line. Several lines have been identified to be relocated by the Contractor with this Contract. This section is referring to newly identified utility or service lines.

E. Limited medical services on a "Good Samaritan" basis: Initial first aid shall be provided by the Contractor. Additional support can be obtained by calling the emergency phone number and identifying the emergency, (on site number 311, the off-site call in number is (352) 563-2943 x2120 for CR 1&2 Main Control Room).

- **Site Coordination Requirements**

A. Another Owner Contractor, PMI Ash, has ongoing operations near the work location. The Contractor must continue to provide access and egress from the PMI work location. The Contractor must provide a design to allow for continued operation by PMI.

B. Prior to bringing any chemical or hazardous material onto CREC property the Contractor must obtain Owner approval.

C. Owner will obtain all environmental permits in support of this work. The Contractor is responsible to comply with the environmental permits.

D. The Construction Contractor will work with Owner personnel and shall obtain local construction permits.

E. Parking facilities. Owner is not financially responsible for any damage or unlawful acts to any Contractor equipment or private vehicles parked in designated parking areas.

- **Temporary Facilities and Utilities**

A. Contractor shall provide, operate, maintain and dispose of all temporary buildings, including change rooms, port-a-potty, & office trailers.

B. Construction water and hydrostatic test water will be identified at points on the job site as designated by Owner's Designated Representative (DR). Connections to and disconnections from water supply shall be by Contractor and coordinated through Owner personnel.

C. The Contractor will be given access, without charge, to limited electrical, and water services in the vicinity of their work site. The quantities and characteristics of these utilities will be limited to that which is available from existing outlets near the work location. The following services will be discussed at the Pre-bid meeting.

1. No electrical power will be provided until the modifications at the CREC substation are complete and the Contractor has brought electrical power to the work location.
2. Non-Potable Water is available within ~¼ mile of the work location.
3. Owner will provide 2 telephone lines and a facsimile line to the Contractors office trailer. This service includes two telephones and local telephone service.
4. The Contractor shall be required to furnish all drinking water.
5. The Contractor may bring limited temporary field offices, tool trailers, etc., on-site for use during performance of the Contract, although there is very limited space. Owner will be provided Office area in a nearby location if desired at no cost to the Contractor. The Owner proposed office location will be identified during the pre-bid conference. The Contractor shall submit the number, type, size, and a sketch of the proposed location of each facility for approval by Owner prior to mobilization.

- **Job Site Perimeter Security Fencing and Access Gates**

The Contractor shall provide temporary fencing to secure work areas, temporary facilities areas materials and equipment storage areas as agreed with and approved by Owner.

- **Telephone Lines**

Telephone line(s) will be provided at the Owner identified office location. Contractor shall be responsible for any use charges or periodic charges associated with the lines assigned to Contractor.

- **Break and Smoking Areas.**

  Smoking is not allowed within any buildings at CREC. Break areas will be approved by Owner.

- **Fire Protection.**

  The Contractor is responsible to identify the need for and provide fire protection of any temporary facilities.

- **Waste Management.**

  The Contractor is responsible to remove any construction generated debris. Office waste will be collected and transported to existing dumpsters west of CR2. No hazardous waste is allowed to be removed by the Contractor.

- **Emergency Eyewash and Showers.**

  The Contractor must provide eyewash and emergency showers at the required locations.

- **Trash Disposal.**

  The Contractor will accumulate and stage trash with and in the Owner trash containers.

- **Temporary Facilities**

  A. Except as otherwise identified, the supply, installation, provision, maintenance, repair, and final removal of all temporary facilities and utilities, necessary for full and complete performance of the Work, is the sole responsibility of the Contractor.

  B. Such items shall include, but not necessarily be limited to, those listed below. The type of facilities, move-in and move-out dates, and locations on the job site shall be subject to and in accordance with the review and approval of Owner.

  C. Asset management program of Contractor's workers, tools, materials, and equipment shall be provided by the Contractor.

  D. Construction Contractor is responsible for landscaping, erosion, dust control; mud, and sand removal are the responsibility of the Contractor. The Contractor shall perform fugitive dust control and submit a Fugitive Dust Control Plan to Owner for review and concurrence.

- **Temporary Facility and Lay-down Area**

  A. Limited roughly graded space near the metrology tower will be provided for Construction material & equipment lay-down.

  B. Upon demobilization, the land previously occupied by Contractor's Temporary Facilities and Lay-down area shall be returned to its pre-construction condition or better. This requirement shall also apply to all Temporary Roads, and Parking, Lay-down areas and Temporary Utilities.

  C. The provision, operation and maintenance of sanitary systems, industrial systems, storm drainage and utility sewage systems for Contractor's Temporary Facilities is the responsibility of the Contractor including collection, holding, processing and disposal.

- **Storage Compounds**

  A. Adequate weather tight storage, for storage of materials, tools and equipment which are subject to damage by weather. The location of storage compounds must be agreed with Owner before materials are brought on site. Such compounds shall be maintained for the storage of the approved materials and for no other purpose.

- **Construction Power Guidelines**

  A. Includes connections to and disconnections from Owner or Owner provided construction power supply, transforming to lower voltage and distribution.

  B. Construction power is for the joint use of all contractors engaged at the job site.

  C. Onsite generation of power is allowed providing that such power is obtained through the use of properly installed, acoustically insulated diesel electric generating units.

  D. Contractor's distribution system, lighting systems and wiring shall be installed in a proper manner and maintained in a satisfactory condition.

  E. No weight shall be imposed upon any electric cable nor staging, ladder or similar equipment shall rest against or be attached to it. Temporary power cables in use by Contractor must be positioned so that they do not cause a tripping hazard (Run 8 ft/2.5 meters overhead or laid neatly out of walkways).

  F. Electrical inspection and oversight will be provided by Contractor.

  G. The Contractor must use of GFI at source for portable tools and equipment / extension cord use.

- **Temporary Facility Area Power, Lighting and Heating Supply**

  A. All electrical installations within temporary buildings shall be in accordance with the NFPA National Electric Code. Inspection and oversight will be provided by a Contractor.

  B. For all equipment the power supply system(s) and components shall meet all National Electric Code (NEC) / National Electric Safety Code (NESC) requirements, and shall be listed by an independent testing laboratory such as Underwriter's Laboratory (UL) or Factory Mutual, suitable for outdoor use when to be used outdoors.

  C. Includes connections to and disconnections from Owner or Owner provided construction power supply, transforming to lower voltage and distribution.

  D. Before Contractor plugs in any electrical appliance to any plug socket belonging to Owner it shall ensure that the appliance is in good condition and is fitted with a suitable cable including fully rated and insulated neutral conductor and protective ground conductor.

  E. Electrical inspection and oversight will be provided by a third party inspector.

  F. Job site excavation rework, and weather repair is the responsibility of the Contractor. Dewatering activities require the prior approval of Owner and a Surface water discharge permit, unless waived by Owner.

- **Construction Water**

  A. Contractor shall provide all temporary water distribution supply lines and water storage facilities. Contractor shall distribute and convey water in an efficient and orderly way. Leaks and waste shall be minimized and care shall be exercised to eliminate the buildup and dispersal of mud resulting from leaks, spills and truck loading operations.

  B. Contractor is also responsible for the safe and proper disposal of water into either local drainage systems or, where these are either not available or water has become contaminated, to off-job-site disposal locations approved by Owner.

- **Potable Water**

  The Contractor shall supply potable water, including ice. The Construction Contractor shall coordinate distribution to points of consumption in appropriate receptacles accompanied by suitable drinking vessels.

- **Testing Water**

  A. Construction Contractor shall provide all distribution, supply lines and water storage facilities. Contractor shall distribute and convey water in an efficient and orderly way. Leaks and waste shall be minimized and care shall be exercised to eliminate the buildup and dispersal of mud resulting from leaks, spills and truck loading operations. Contractor shall provide all requisite corrosion inhibitors, antifreeze and other additives required to perform testing in accordance with specification.

  B. Construction Contractor is also responsible for the safe and proper disposal of water into either local drainage systems or, where these are either not available or water has become contaminated, to off construction-site disposal locations approved by Owner.

- **Water Disposal and De-watering**

  Construction Contractor shall perform all necessary de-watering and permitted disposal of ground water. Storm drainage, surface drainage and discharge of construction wastes shall be managed to prevent pooling of water on the job site and to prevent interference with the operations of other Contractors and organizations on or adjacent to the discharge areas.

- **Sanitary Facilities**

  A. Contractor shall provide and operate his sewage facilities in a manner that eliminates health risks, and obnoxious odors.

  B. Contractor shall be responsible for all temporary sanitary facilities, including janitorial services, storage and removal of sewage. All temporary toilets shall be kept in a constant sanitary condition and shall be in compliance with all applicable health or other regulations. Portable enclosed toilets may be used in construction and fabrication areas provided they are regularly attended and maintained. Before completion all toilet facilities shall be removed and their areas disinfected and filled.

- **Fuels and Lubricants**

  A. Oils, greases and similar materials must be stored in fire proof bins or buildings or in a fenced compound remote from other combustible materials as approved by Owner.

  B. "No smoking" signs shall be provided by Contractor and prominently displayed in areas where flammable materials are stored. Additionally, Contractor shall provide and maintain suitable fire extinguisher in such areas.

  C. Contractor shall provide all fuel for heating, ventilation and air conditioning of Temporary Facilities (unless these are run using free issue power).

  D. The Contractor must use appropriate fire control containments for vessels storing fuels and lubricants.

- **Communication Facilities**

  A. Contractor shall provide and operate all means of communication, including but not limited to telephones, facsimiles, and radios which shall be approved by Owner. Owner shall provide telephone lines in accordance with the provisions of 9.3.

  B. Compressed Air, Steam, and Gases

  These services will be provided by the Contractor's design and approved by Owner.

- **Temporary Roads, Parking, and Traffic Control**

  A. The Design Contractor shall design for temporary roads and traffic control.

    a. The Construction Contractor shall be responsible for providing and maintaining all roads and parking areas deemed necessary by Contractor for access, and parking in Temporary Facilities areas, construction areas, and between areas. Contractor provided roads and parking areas shall be constructed so as to provide for adequate safe movement of light and heavy vehicles, and equipment. Contractor's temporary roads shall be constructed in a manner ensuring the avoidance of damage to all permanent roads, facilities, and underground structures.

    b. Contractor shall maintain his temporary roads and parking areas regularly, and shall water all his roads as a dust abatement measure.

    c. Contractor shall remove and restore areas occupied by Temporary roads and parking areas upon completion of the Work.

    d. Temporary construction steel, decommissioning and miscellaneous equipment supports, platforms, and ladders around equipment are the responsibility of the Contractor.

    e. Project signs for traffic control, and direction, and for identifying project areas. Signage shall be based where possible on International signage standards and conventions

    f. Transportation facilities on and off job site. Only Contractor vehicles, as approved by Owner, will be allowed on the job site. Limited personal vehicles will be allowed on site. The Contractor's personnel may be required to use

Owner provided shuttle transportation, during specific periods of high activity (i.e. 2009 outage – September through December).

g. Equipment delivery slippages in schedule are the responsibility of the Contractor.

- **Material Handling, Rigging, and Scaffolding**

A. The design Contractor will provide for the following in their design documents:

1. Contractor shall provide and operate all cranes and other necessary equipment for handling; hauling, unloading and receiving Contractor supplied materials, tools and equipment.
2. Containers and services for hauling, removal and disposal of construction waste and debris. Contractor shall advise Owner in writing of any need for disposal of hazardous waste prior to generation of the waste. The Contractor is responsible to properly package, label, and turn the waste over to Owner. Owner will dispose of all hazardous waste generated at CREC.
3. Supply, erection, maintenance and dismantling of scaffolding and other means of access to the Work

- **Weather Protection**

Weather Protection of the Work and any methods required to allow continuation of the Work during periods of inclement weather.

The Contractor is responsible for the proper storage of all equipment and material. There is no protected storage currently available for use by the Contractor.

- **Equipment**

A. Small tools

The Contractor will provide all small tools.

B. All standard expendable or consumable construction items and supplies.

The Contractor is responsible for expendable or consumable construction items and supplies.

C. Temporary lighting. Provision and operation to allow the Work to be performed in a safe manner regardless of ambient lighting conditions.

The Contractor is responsible for temporary lighting.

- **Personnel Protective Equipment**

The Contractor is responsible for identifying and providing all personnel protective clothing.

- **Permits**

Owner is responsible for obtaining environmental permits, licenses and government approvals for the Contractor. The Contractor will obtain all local construction permits, (coordinated through Owner). It is the Contractor's sole responsibility to ensure compliance with permits in accordance with all laws and regulations.

- **First Aid Facilities**

  CREC has first aid responders and there is a hospital near the site. The Contractor is responsible to provide immediate medical attention and CREC notifications if an emergency condition is identified.

- **Calibration**

  The Contractor will identify the instruments to be calibrated. Construction guidelines should contain the requirement that equipment provided and installed by the Contractor shall be calibrated, and maintained by the Contractor until contract completion or system turn-over.

- **Spare Parts**

  A. Spare parts lists will be proved by the Contractor. The Contractor shall:

     1. Provide a list of recommended spare parts to Owner for approval. Include pricing, delivery time, description, etc.
     2. Coordinate delivery of spare parts to the Owner approved location.
     3. Label spare parts, as directed by Owner.

- **Documentation and Turn-over**

  A. The design Contractor will provide for the following in their design documents:

     1. The contractor will be required to participate in the project turnover process by assisting Owner in developing and completing the project punch list. The contractor shall notify Owner no later than one (1) day after completing the punch list item(s).
     2. The following construction documentation will be maintained through the construction and turned over during the testing and acceptance period prior to declaring facilities as mechanically or substantially complete:

        a. Operating manuals,

        b. Maintenance manuals,

        c. Spare parts lists,

        d. Equipment specifications and manufacturers information,

        e. MSDS library,

        f. As-built/as-installed verified construction/assembly drawings, and

        g. Supporting shop-drawings, isometric drawings, weld maps, and inspection and testing records.

        h. The Contractor must provide input for and assist in development of post construction operating procedures with Owner personnel.

- **Construction debris**

  The design Contractor will provide for the following in their design documents:

ATTACHMENT C

NOT USED

ATTACHMENT D

PHASE 2 CONCEPTUAL DESIGN REPORT

ATTACHMENT E

REQUEST FOR INFORMATION FORM

RFI Number:										
POINT OF DISCHARGE (POD) PROJECT REQUEST FOR INFORMATION (RFI) FORM										
Date:						Contractor's Project Manager Approval:				
Initiator:										
Suggested resolution:										
Date that response is needed by to prevent Project Impact:										
Potential Impact										
Scope			Schedule			Cost			Safety	
Description of Impact:										
Progress Energy Direction, Resolution, Clarification										
Contract Change Required (Yes or No)										
Owner Project Manager Receipt Acknowledgement:										
								Date:		
Project Manager Disposition Approval:										
								Date:		
EPC Project Manager Disposition Approval:										
								Date:		
Contract Change Complete (Yes or No)										
Owner Procurement Specialist Contract Change Complete Acknowledgement:										
								Date:		

PART III

CONTRACT PRICING

1.0 CONTRACT PRICE

Owner will pay the Contractor as full compensation for the completion of Work described above and performed and accepted by Owner under this Contract, the firm, fixed price of thirteen million seven hundred fifty eight thousand dollars ($13,758,000).

Payments shall be invoiced in accordance with the following Milestone Schedule. The following table, Table 1 – Project Milestones Payment Schedule, lists the Payment Milestones and the amount to be paid upon acceptance of each deliverable item by Owner. Owner will accept a deliverable item for payment when sufficient tests or documentation reviews have been made to support a determination that the item meets the requirements of this Contract issued for its delivery, and will not be unduly delayed beyond a reasonable time for completion of the tests and documentation reviews. Acceptance of the deliverable, and approval that the deliverable has been met, will be confirmed in writing by Owner's Designated Representative. Acceptance of any deliverable or final acceptance by Owner shall not be deemed a waiver of any other right or remedy available under this Contract or at law nor shall it release Contractor from its obligations with respect to any defective deliverable.

Milestone	Description	Estimated Date	Payment Amount
Submittal Drawings/ Data	Drawings, foundation loads and interface details sufficient for Engineering Contractor to complete their work received by Owner	March 23, 2009	5%
Safety Plan	Site Specific Safety Plan accepted by Owner	July 1, 2009	5%
Completion of Detailed Engineering	All detailed Engineering documents accepted by Owner. Completion of this phase allows for release of all bills of material to fabricate FRP pultruded framing members, tower hardware, and remaining cooling tower components	August 30, 2009	20%
Mobilization at Site	Begin receipt of materials and secure equipment rental, safety plan, complete in-processing of all Contractor employees	September 1, 2010	30%
Begin Construction	Begin site construction activities, framing, piping, fill, eliminators, mechanical equipment, etc.	October 1, 2010	10%
Substantial Completion	Tower completed, punch-list developed, ready for commissioning.	April 30, 2011	30%
Mechanical Completion	Tower has successfully completed all commissioning protocols, all punch-list items complete, all components functionally tested received final acceptance, and is ready to be put into service by Owner.	May 31, 2011	50% of Retention
Final Acceptance	Tower has successfully passed 3rd party CTI performance testing, Contractor's personnel demobilized, clean-up performed	August 31, 2011	50% of Retention

These milestones must be achieved by Contractor and verified as complete by Owner prior to release of scheduled payments. Each of the deliverables for the Milestones will have a cover sheet attached, requiring Owner's approval of the deliverable. The cover sheet will be signed by Owner and electronically transmitted to Contractor as a condition of payment.

Owner and Contractor shall develop the acceptance test criteria in order to comply with the intent of this Section.

Plant Access Training and Radiation Worker Training are included in the Contract Lump sum price. Owner will not pay for any re-training required as a result of Contractor Employees' failure to satisfactorily complete the initial training.

2.0 NOT USED

3.0 PRICING BASIS

The Contract Price set forth herein is firm for the duration of the Work and includes all Contractor's costs, expenses, overhead and profit for complete performance of the Work including the following indirect costs.

3.1 MOBILIZATION

The lump sum price set forth in Section 1, PART III, shall include, but not be limited to all costs, direct and indirect, for the following Work Site activities:

- Recruitment and transportation of labor and supervision from the point of origin to the Work Site.
- Supply, transport and installation as required, of all temporary facilities/offices, associated equipment and tools required in performance of the Work. This includes any further alterations of Contractor's temporary facility area or for any alterations to the area status after acceptance by Contractor.
- The submittal to Owner of Contractor's approved safety program including modifications as requested by Owner.
- This submittal to Owner of Contractor's approved security program including modifications as requested by Owner.
- The submittal to Owner of Contractor's approved quality assurance and quality control program including modifications requested by Owner.
- The submittal to Owner of Contractor's Contract Schedule and other detailed schedules.
- The submittal to Owner of Contractor's Project Plan.
- The submittal to Owner of Contractor's Environmental and Safety Plan.
- The submittal to Owner of Contractor's Quality Control Plan.

3.2 DEMOBILIZATION

The lump sum price for demobilization set forth in Section 1, PART III shall include but not be limited to all costs, direct and indirect for the removal of labor and supervision from the work site, removal of all temporary facilities and equipment from the work site, submittal of all data including as-built drawings, clean up and final clearance of the work site and reinstatement of the area(s) to the condition originally received from Owner.

3.3 SITE ESTABLISHMENT

The lump sum price set forth in Section 1.1, Part III shall include but not be limited to the Contractor's overhead costs and other general expenses to maintain the site establishment (i.e. Contractor's presence) on the work site for performance of the Work and shall include, but not necessarily be limited, to the following:

- All supervision/management staff above the level of General Foreman.
- All field and home office overheads including field administration, field transportation and temporary facilities.
- The effective control and conduct of Contractor's Environmental and Safety Program, Quality Control Plan, and Project Plan.
- The maintenance and issue of Contractor's schedules.
- The effective control of quality through Contractor's quality assurance and control program.
- Material control and maintenance of records, including offloading, temporary storage, any necessary re-handling of materials and weather protection for materials.
- Maintenance and cleanliness of the work site infrastructure areas, temporary facilities area and temporary buildings.
- Specifically excluded from this item are all direct costs associated with the performance of the Work and Contractor's profit, which are to be included in other line items of the lump sum/unit price portion of the Work.

3.4 ADDITIONAL SITE ESTABLISHMENT

In the event that an additional and/or reduced number of indirect resources are required to perform the Work, and Owner agrees that these are due to effects other than those within the responsibility of the Contractor, the lump sum price may, with prior Owner approval, be modified using the rates set forth herein.

In any event the indirect lump sum price for Site Establishment shall not be subject to any change should the direct lump sum/unit price portions of the work vary by up to and including +/- twenty-five percent (25%) of the original contract value.

The lump sum for site establishment shall not be subject to re-measurement, except as stated herein.

The rates set forth in Schedule A herein shall be used only for the purposes of evaluation of such an agreed change.

4.0 PRICING FOR CHANGES (CHANGE ORDERS) AND ADDITIONAL WORK

Adjustments to the Contract Price for any Change in the Scope of Work shall be in accordance with the provisions of the Section entitled CHANGES set forth in Section 18 of PART I.

Owner may request, and Contractor shall provide, proposals for Scope of Work Changes (additions and deletions) which are priced, at Owner's option, by one or a combination of the following methods:

a. Negotiated Lump Sums based upon a mutually agreed Scope of Work.

b. Applicable unit prices set forth below, if the Work is possible to be fairly classified under the Unit Price items.

c. Negotiated Unit Prices not established in the Contract.

d. On a "cost-plus" basis or at the labor and equipment T&M rates as set forth in the attachment Commercial Schedules.

The payments provided shall be full payment for all work associated with a change. The calculated payment shall cover all expenses of every nature, kind, and description and any others incurred on the work being paid for under the Change Order.

4.1 Unit Pricing (Not Used)

4.2 Subcontracts

4.2.1 All subcontracts and services provided by others for performance of Changes or extra work requested by Owner, which have been approved by Owner shall be at actual cost to Contractor of such subcontracts or services provided by others (not to exceed such subcontract price) plus a mark-up as noted below.

When Changed Work is expected to be performed by one or more approved subcontractors, or by lower-tier subcontractors or suppliers, the subcontractor shall furnish its cost breakdown in accordance with Section 4. Contractor will be allowed an additional markup of 10% (ten percent) as indicated below, applied to the costs computed for work done by each subcontractor, to compensate for all administrative costs, including project, overhead, general company overhead, profit, bonding, insurance, Business & Occupation tax, and any other costs incurred. See Schedule E.

4.2.2 Specialized Services

Compensation for specialized third party services necessary to perform the changed work shall be estimated on the basis of a proposal from the providing entity. A "specialized service" shall be one that is typically billed through invoice in standard industry practice. Owner may require Contractor to obtain multiple quotations for the service to be utilized and select the provider with prices and terms most advantageous to the Owner.

Owner will pay Contractor an additional ten percent (10%) of the sum of the costs for specialized services to cover project overhead, general company overhead, profit, bonding, insurance, Business & Occupation tax, and any other costs incurred.

4.3 Materials

4.3.1 In the event of Changes (additions or deletion) to the Scope of Work, and additional material are received, Contractor will supply materials at pricing provided in Schedule B

Compensation to Contractor for materials supplied by Contractor that do not appear in Schedule B, required for incorporation into the permanent facility (excluding consumable, expendable, and small tools) which cost Contractor less than *One Thousand Dollars* ($1000.00) per item shall be at actual invoiced cost to Contractor, including transportation to site, as substantiated by invoices certified paid or by such documentation as may be required by Owner, plus a mark-up, for all profit and overhead expense of Contractor thereon, not to exceed ten percent (10%). Contractor's providing materials for the Work, shall be listed in Schedule F.

4.3.2 Owner reserves the right to provide, at no cost to Contractor, materials, equipment, services, supplies or incidentals required to perform the Work. All refunds, trade discounts, rebates on materials, supplies and services, and all monies obtained from the disposal of surplus materials or supplies shall accrue to Owner.

4.3.3 If quotes are not available for materials, material prices may be based on commonly accepted buyer's guides or other, best-available data.

4.4 Labor

Compensation to Contractor for construction labor, related costs and profit authorized at Time and Material rates shall be in accordance with the rates set forth in Commercial Schedule C entitled ALL INCLUSIVE LABOR RATES attached and incorporated herein.

Labor reimbursement calculations shall be based on a "Project Labor Rate Sheet" (Labor Rate) prepared and submitted by the Contractor and by any subcontractor before that firm commences changed or added work. The project labor rate sheet is intended to reflect Contractor's actual cost incurred without any mark-up for overheads or profit. Once a Labor Rate is approved by the Owner, it shall be used to calculate the labor cost for any change until a new List is submitted and approved. The

Owner may compare the Labor Rate to payrolls, prevailing wage determinations, union agreements and other documents and may, at any time, require the Contractor to submit a new Labor Rate. The Contractor may submit a new Labor Rate at any time without such a requirement that will be reviewed and accepted or rejected as Owner deems reasonable. Prior payment calculations shall not be adjusted as a result of a new Labor Rate.

To be approved, the Labor Rate must be accurate, auditable and meet the requirements of this Section. It shall include regular time and overtime rates for all employees (or work classifications) expected to participate in changed work. The rates shall include and separately list the basic wage and fringe benefits, the current rates for all withholding or taxes required by Law, the company's present rates for Industrial Insurance premiums and the planned payments for travel and per diem compensation. The rates if applicable shall also include an allocation of costs of small tools and consumable supplies, as well as safety and health testing. This allocation shall assure that the amount included for Changed Work is reasonably proportional to the total costs applied to all Work.

In the event that an acceptable initial Labor Rate or requested revised Labor Rate is not received by the time that a Change Order estimate is begun, Owner may, at its sole discretion, develop a Labor Rate unilaterally, utilizing the best data available, that will be used until a Contractor's Labor Rate is received and approved.

Estimated man-hours for the Changed Work shall be determined using the standard estimating book rates noted below to establish the maximum allowable man-hours for each anticipated task. For work types other than mechanical and electrical, Contractor may propose the use of other standard estimating books and shall include with his detailed proposal copies of the applicable pages justifying the selected factor. Included in the estimated man-hours for labor shall be sufficient man-hours to recover any anticipated lost time, inefficiency or other impact on the Work directly or indirectly related to the Changed Work. Contractor is to provide a detailed breakdown of the Work along with the associated hours and not just a lump sum of hours. Where the Contractor includes a composite rate for labor, he shall provide a breakdown detailing how each such composite rate was determined.

4.5 Equipment Rental

4.5.1 Equipment rental rates as set forth in Schedule D herein shall apply for equipment used for extra Change Work requested by Owner.

4.5.2 For equipment which is specifically mobilized to the jobsite for extra Change Work, Contractor shall separately identify such transportation costs (including: loading, off-loading, assembly and disassembly) when submitting proposals to Owner for performing extra work. Transportation costs shall not be applicable to equipment already mobilized on the site.

4.5.3 When Contractor's equipment does not resemble the equipment having rental rates listed in Schedule D for extra Change Work, the rental rate shall be negotiated and agreed upon in writing by Owner.

4.5.4 Compensation to Contractor for equipment used for extra Change Work which is rented from third parties and does not resemble the equipment having rental rates listed in Schedule D, must be approved by Owner in writing prior to rental and shall be at actual cost to Contractor, including transportation to site, as substantiated by invoices certified paid or by such documentation as may be required by Owner plus a mark-up, for all profit and overhead expense of Contractor thereon, of 10 %.

4.5.5 The equipment provided by the Contractor shall be of modern design and in good working condition. For the purpose of this provision, "provided" shall mean that the equipment is owned (either through outright ownership or through a long-term lease) and operated by Contractor or his subcontractor or that the equipment is rented and operated by Contractor or his subcontractor. Equipment that is rented with operator shall not be included here, but shall be considered a service and addressed according to Section 4.2.2 above.

The amount of payment for any Contractor-owned equipment is expected to be no greater than the rates that could be obtained from third party companies in the area. Rates may be determined according to the equipment rate sheet provided by Contractor provided the same are deemed to effect at the time the estimate is prepared, or 70% of the rates listed in the Rental Rate Blue Book, whichever is less. The selected rate shall be full compensation for all fuel, oil, lubrication, ordinary repairs, maintenance, and all other costs incidental to furnishing and operating the equipment except labor for operation. Payment for rented equipment will be made on the basis of a valid quotation or rental invoices for similar equipment covering the time period of the work. Owner may survey the open market in the vicinity and require Contractor to fully justify the use of any higher rate.

In addition to the payments for Contractor-owned and rented equipment, Owner will pay Contractor ten percent (10%) of the equipment costs to cover project overhead, general company overhead, profit, bonding, insurance, Business & Occupation tax, and any other costs incurred.

Equipment utilized by Contractor with an original acquisition value of $1,000 or less is considered small tools and will not be billed under this section.

4.6 Time Sheets

For all work performed on a cost-plus T&M basis, Contractor shall submit daily time sheets for approval by Owner. An approved copy of the time sheets, which shall detail all hours worked, materials installed and equipment used, must be submitted in support of Contractor's monthly billing.

5.0 <u>CHANGE (CHANGE ORDER) PROCESS</u>

Each Party may make written requests for Changes. All Changes shall be identified in, and performed pursuant to, a Change Order. No Changes shall be performed by Contractor prior to the submission to, and execution by Owner and Contractor of a Change Order (except as provided in 18.4, Part I) that describes in detail all of the following that are applicable and necessary: (A) the Scope of the Change, (B) any amendment of or adjustment to the Contract Amount and applicable Schedule of

Values, (C) any adjustment of the Schedule or the Guaranteed Completion Date, and (D) the effect on Contractor's ability to comply with its obligations under this Contract including (without limitation) the Performance Guarantees. All Change Order information as noted above shall be documented and approved on the RFI Form provided herein as Part II Attachment F.

Upon receipt by Contractor of a written request for a Change from Owner or upon submission by Contractor to Owner of a written request for a Change, Contractor shall furnish to Owner within Seven (7) days, a statement setting forth in detail, with a breakdown by trades satisfactory to Owner, Contractor's estimate of the adjustments in the Contract Amount and the applicable Schedule of Values attributable to the Change, together with Contractor's estimate of changes in the Schedule. If both Parties approve in writing such estimate by Contractor, and the written request for the Change meets the requirements of the change process, it shall constitute a Change Order and (A) Contractor shall perform the Work as described therein and (B) the Scope of Work, the Specifications, the Contract Amount, Schedule of Values and the Schedule shall be accordingly revised, amended or adjusted pursuant to such Change Order and documented on the RFI Form.

Except to the extent a Change Order specifically amends one or more provisions hereof, all provisions of this Contract shall apply to all Changes, and no Change shall be implied as a result of any other Change.

6.0 CONTRACT AMENDMENTS

One or more Change Orders may constitute a Contract Amendment. When a single Change Order or an aggregate of Change Orders, exceed(s) the value of $100,000, then the Change Order(s) must be incorporated into a Contract Amendment.

The Contract amendment is the only document by which the Contract may be changed.

6.1 Owner will prepare all Contract Amendments.

6.2 Changes covered by an Amendment may include:

- Added or deleted Work as detailed by the Change Order(s).
- Revised drawings or specifications
- Modified conditions for performance of work or unforeseen field conditions
- Authorization of overtime
- Revised requirements for Owner or Contractor furnished materials, equipment or services
- Schedule revisions
- Alteration or removal of completed Work

6.3 Both Owner and Contractor's authorized representatives shall execute all Contract Amendments.

7.0 FIXED PRICE / COMPENSATION

All costs and expenses of all items expressly stated in PART III to this Contract or elsewhere in this Contract to be at the cost or expense of or for the account of Contractor, or to be performed by Contractor at no additional cost to Owner, and all costs and expenses of Contractor to perform the Work, shall not be reimbursable costs under the provision of this Section 7.0 and shall be deemed included within the mark-ups for overhead or profit set forth in this Section 7.0.

8.0 TIME AND MATERIALS

In addition to the Fixed Price portion of this Contract, Owner may authorize Contractor to perform supplemental Work on a time and material basis. Contractor will be compensated for authorized time and materials Work performed under this Contract based on the attached Pricing Schedules A, B, C and D attached.

These rates shall remain in effect without revision for a minimum period of twenty (20) months from the effective date of this agreement. Should either party desire to revise such rates after that time, such party shall provide the other with a minimum sixty (60) days written notice of such desire. Revisions may be made only by a written Contract Amendment executed by both parties. Oral modifications to the Schedules have no effect. New rates requested by Contractor shall be no less favorable than those charged by Contractor to other parties for similar work.

When Contractor and Owner cannot agree on the scope and lump sum value of a Change Order, or as otherwise determined by the needs of the Project, Owner may call for work or material to be paid for on a T&M basis. If so, then the objective of this procedure is to reimburse the Contractor for all costs actually incurred in performing the Changed or additional Work, including costs of labor, small tools, supplies, equipment, specialized services, materials, applicable taxes and overhead and to include a profit commensurate with those costs. The amount to be paid shall be determined in accordance with the general categories of costs described above, but labor costs will be based upon time sheets (time sheets to be submitted for Owner verification on a daily basis) showing actual hours spent, and material and other third party costs will be based upon actual invoiced amounts. The payments provided above shall be full payment for all work done on a T&M basis. The calculated payment shall cover all expenses of every nature, kind, and description, including those listed above and any others incurred on the Work being paid through T&M. Nothing in this provision shall preclude the Contractor from seeking an extension of time or time-related damages to unchanged work arising as a result of the T&M work. The amount and costs of any work to be paid by T&M shall be computed by the Contractor based on the criteria described above, and the result shall be submitted with complete back-up documentation for audit and approval by Owner before Contractor submits an invoice for payment.

9.0 INVOICES AND PAYMENTS

When authorized Work is performed under this Contract, payment of the agreed upon compensation will be made by Owner. All payments, including the final payment, are subject to set off and/or adjustment during performance of the Work, after completion of the Work, or after termination of Work on the basis of any final accounting which may be made by Owner. Owner may withhold from any payment, including the final payment: (1) any amount incorrectly invoiced; (2) any amount in dispute; (3) or an amount sufficient to completely protect Owner from any loss, damage or expense arising out of assertions by other parties of any claim or lien arising out of or in connection with the Work, (4) any amount due under the indemnity provisions of this agreement; (5)

defective Work not remedied; (6) reasonable evidence that the Work will not be completed within the Contract time, and that the unpaid balance would not be adequate to cover actual or liquidated damages for the anticipated delay. The undisputed portion of any invoice shall be paid by Owner as hereinafter provided.

Invoices for Work performed under this Contract shall be sent to:

Crystal River Nuclear Plant 3
15760 West Powerline Street
Crystal River, FL 34428-6708
Attn: Accounting Representative

Each invoice and all supporting documents shall show the Owner Contract number. Invoice items must be identifiable to the pricing schedule in order to be accepted for payment.

If requested by Owner, Contractor shall supply a general release of all claims or liens related to the authorized Work, or affidavits that all bills for materials and labor have been paid and receipts showing the payment of these bills. Failure or refusal by Contractor to comply with such request shall excuse Owner from making any further payments to Contractor until Contractor does comply. Owner reserves the right to pay any outstanding obligations of Contractor for labor and materials used in the authorized Work by a check made payable jointly to Contractor and Contractor's Contractors, subcontractors or employees. Any payment made in this manner shall apply as a payment to Contractor under this Contract. Owner may deduct from any payment any amounts owed to Owner by Contractor.

Each invoice shall show the Contract number. If the Work is being performed on a time-and-materials basis, the invoice shall include a statement or be accompanied by time sheets showing each employee's name, classification, hours worked, and the applicable rate of compensation to Contractor. On-site labor, off-site labor, material and equipment costs must appear separately on the invoice. If any equipment has been used for which a charge applies, the invoice must also specify the equipment used, hours of usage and rate of reimbursement for use. Any tax paid on material or equipment must be shown separately from the sale or rental price of those items. In no instance shall the price invoiced for Contractor's material drawn from Contractor's stock exceed the prevailing price that Owner could obtain for comparable quantities and types of material from commercial Contractors.

Unless otherwise specified in the Contract, Contractor is responsible for paying the lowest allowable sales or use tax rate under applicable law for materials supplied under this Contract. Invoices submitted which include payment of tax at higher than the statutorily allowed rate shall be reduced to reflect only the amount Contractor was legally required to pay. Any excess amount paid by Contractor will not be reimbursed to Contractor.

Subject to the above conditions, payments will be made not later than thirty (30) days after receipt of a correct invoice covering the Work has been presented to Owner.

Subject to the above conditions final payment will be made not later than thirty (30) days after all of the following have been completed:

(1) All Work has been completed and accepted, including outstanding punch list items, final cleanup, testing, demobilization, and receipt of all required documentation by Owner.

(2) A correct invoice covering the Work has been presented to Owner.

(3) A properly executed Release from Contractor included as Part I, Attachment C to this Contract, together with any other requested general release, affidavits or receipts have been provided to Owner.

In addition to any amounts withheld due to any of the four (4) conditions set forth in the first paragraph of this subsection, Owner shall have the right to withhold a maximum retention of ten percent (10%) of each invoice written to cover mobilization and all Work thereafter including extra Change Work until the final payment is made.

The Final and/or Retention Invoice shall be submitted for final payment after completion and acceptance of Work by Owner and compliance by Contractor with all terms of this Contract. This invoice shall contain a complete itemized listing of Progress and Additional Work Invoices by number, date, gross amount, retention amount, and the total amount of sums retained and due. It shall also contain, or be supported by a written acceptance of the Work signed by Owner and a Certification and Release in accordance with this Section. Unless otherwise required by applicable law, final payment shall be made within 30 calendar days after completion and acceptance of all Work or 30 calendar days after receipt of a proper invoice and supporting documents satisfactory to Owner whichever occurs later. Final payment shall not relieve Contractor of any obligation under this Contract.

So long as Owner has paid all undisputed portions of each invoice due to Contractor, Contractor shall continue to diligently pursue its Work without interruption, suspension or stoppage.

9.1 OVERTIME AND PORTAL-TO-PORTAL PAY

Unless otherwise specified in the rate schedule, no payment will be made for time and expense in traveling to or from the job site. As far as possible, Work will be scheduled for five (5) consecutive eight (8) hour week days. Payments for work over a specified number of hours or on certain days at rates higher than a specified straight-time rate will only be made if both the hours for which the overtime rate is applicable and the rate itself are clearly specified in an agreed upon rate schedule. Absent such agreement all time shall be invoiced at the same rate, regardless of the days or hours worked. In calculating any overtime payable to Contractor, only hours worked for Owner will be considered.

Unless expressly stated elsewhere in this Contract, Work at the jobsites shall be compatible with Owner's starting and quitting times or other times approved by Owner. Scheduled overtime work by Contractor must be approved in advance and in writing by Owner. Contractor shall notify Owner in advance of any incidental spot overtime which Contractor elects to work due to such operations as concrete placement, nondisruptable work activities and emergencies to protect life and/or property. Overtime work, whether scheduled or incidental, shall be to Contractor's account unless the compensation therefore is specifically authorized in writing by Owner. In the event Owner approves compensation of Contractor's overtime in advance, such compensation as separately authorized shall be limited to the actual cost to Contractor of the premium portion only of all applicable wages, craft fringe benefits, and payroll burdens imposed by any governmental authority and measured by the compensation payable to employees. To establish the amount of payment, Contractor shall submit supporting documents satisfactory in form and content to Owner for its verification and approval.

9.2 OVERBILLINGS/OFFSETS/CREDITS/REFUNDS

Owner may charge and collect interest from the Contractor on any overbillings, offsets, credits or refunds that may become due to Owner under this Contract. Interest shall be paid at the rate of the average prime rate of interest as listed in the Wall Street Journal Money Rates Section plus two percent (2%). Interest shall cover the period of time from the date the overpayment, error or basis for refund or offset occurred to the date the amount is paid. The Contractor may be notified of the overbilling by credit memorandum or by invoice. Payment of the total overbilling, offset, credit or refund plus interest shall become due to Owner immediately upon Contractor's receipt.

9.3 NOT USED

9.4 SAFETY INCENTIVE

Contractor is expected to perform the Work in a safe manner. The Owner and Contractor have agreed to provide certain revenue at risk if the following safe working standards are maintained. The standards and the revenue at risk are outlined in Schedule E.

10.0 BACKCHARGES

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

12.0 HNP CT REFILL CREDITS

Harris Nuclear Plant (HNP) will be performing a repack of the fill in the natural draft hyperbolic Cooling Tower in the near future. The work for this repack will be competitively bid. In order to promote fleet-wide efficiencies, if Contractor is awarded the repack work within a competitive bid process, then Contractor shall provide an additional one hundred fifteen thousand dollar ($115,000) credit on the repack work once their opportunity to prove their "Best and Final" has been exercised.

13.0 MOTOR OPERATED VALVE OPERATORS

Contractor shall provide the labor and installation to install Limitorque brand Motor Operated Valve Operators in the Ring Header for the Tower. These operators will be procured either by Owner and provided to Contractor or will be procured by Contractor under an amendment to this Contract. However, the cost for the cabling, installation, wiring, cable supports, and other items necessary to install and operate these valves, apart from the motorized valve operators themselves, is included in the price of this Contract.

The Contract also includes the installation of sixteen (16) platforms providing access to the actuators for these valve operators. The price of these platforms is seventy six thousand dollars ($76,000) and is already included in the Contract Price. If the Ring Header is installed at or below grade, then these platforms will not be needed and the Contract will be amended to remove this seventy six thousand dollars from the overall Contract Price.

14.0 COMMERCIAL SCHEDULES

SCHEDULE A - PRICING FOR INDIRECTS

SCHEDULE B - UNIT PRICES AND METHODS OF MEASUREMENT

SCHEDULE C - ALL INCLUSIVE LABOR RATES

SCHEDULE D - NOT USED

SCHEDULE E - SAFETY INCENTIVES/REVENUE AT RISK

SCHEDULE F - LIST OF MATERIAL CONTRACTORS

SCHEDULE G - NOT USED

SCHEDULE H - SCHEDULE OF VALUES

SCHEDULE I - CONTRACT AMENDMENT

SCHEDULE J - CONTRACTOR'S TIME SHEET

SCHEDULE K - BACK CHARGE AGREEMENT

PRICING FOR INDIRECTS

Indirect RateCategory	Daily Rate	Straight-Time Hourly Rate	Overtime Hourly Rate	Total
Total				

(Add or delete category items as appropriate)

MOBILIZATION

Mobilization with respect to changed Work is defined as the preparatory work performed by the Contractor including procurement, loading and transportation of tools and equipment, and personal travel time (when such travel time is a contractual obligation of the Contractor or a customary payment for the Contractor to all employees), and will be included for reimbursement only if the cost is expected to be incurred solely as a result of the changed Work. Mobilization also includes the costs incurred during demobilization. Owner will pay for mobilization for off-site preparatory work for changed at cost without additional markup to the extent deemed necessary by Owner.

END OF COMMERCIAL SCHEDULE – A

SCHEDULE B

MATERIAL PRICING

	Unit Prices		
Item	Unit	Price	Installation

[redacted]

[redacted]

NOT USED

[redacted]

LIST OF MATERIAL CONTRACTORS

The following is a detailed list of Contractor's material Contractors proposed for the Work, together with the brand name and the country of origin of the materials supplied.

Once approved, the material Contractors listed below shall not be changed except with Owner's prior written approval.

Material Contractor	Materials	Brand Name	Country of Origin	Value of Purchase Order

NOT USED

[redacted]

[redacted]

[redacted]

CONTRACT AMENDMENT

CONTRACTOR		DATE
CONTRACT NUMBER	CONTRACT MODIFICATION	ATTENTION

EXCEPT AS OTHERWISE EXPRESSLY PROVIDED HEREIN, CONTRACTOR HEREBY AGREES TO PERFORM THE BELOW-DESCRIBED WORK IN ACCORDANCE WITH ALL OF THE TERMS AND CONDITIONS OF THE CONTRACT REFERENCED ABOVE. CONTRACTOR'S INVOICES MUST

DESCRIPTION	PRICING

PERFORMANCE OF THIS WORK ________ AND MUST BE COMPLETED NO ________

ORIGINAL CONTRACT ________

PREVIOUS CONTRACT ________ THRU ________ ________

AMOUNT THIS ☐ ☐ ☐ ☐ FIRM ________

CURRENT CONTRACT VALUE (EXCLUDING BONDING COSTS) ________

CURRENT BONDING COST ________

EFFECT ON CONTRACT SCHEDULE

THIS CONTRACT MODIFICATION REPRESENTS FINAL ADJUSTMENT FOR ANY AND ALL AMOUNTS DUE OR TO BECOME DUE CONTRACTOR FOR CHANGES REFERRED TO HEREIN. CONTRACTOR FURTHER RELEASES ALL OTHER CLAIMS, IF ANY (EXCEPT THOSE CLAIMS PREVIOUSLY SUBMITTED IN WRITING IN STRICT ACCORDANCE WITH THE CONTRACT), FOR ADDITIONAL COMPENSATION UNDER THIS CONTRACT, INCLUDING WITHOUT LIMITATION

SIGNATURE

CONTRACTOR	TITLE	DATE
OWNER	TITLE	DATE

CONTRACTOR'S DAILY TIME SHEET

NAME	TR	HOURS	RATE	TOTAL	NAME	TR	HOURS	RATE	TOTAL
			TOTAL					TOTAL	

EQUIPMENT	HOURS	RATE	TOTAL	EQUIPMENT	HOURS	RATE	TOTAL
		TOTAL				TOTAL	

MATL	NO.	COST	%	TOTAL	MATL	NO.	COST	%	TOTAL
			TOTAL					TOTAL	

Contract No. 433059: Part III: Schedule K

CONTRACT BACKCHARGE AGREEMENT

DATE	CONTRACT NO.	BACKCHARGE NO.	CONTRACTOR
CONTRACT TITLE			

I. DESCRIPTION OF BACKCHARGE WORK (If additional space is required, attach a separate sheet.)

II. PRICING BASIS (Check applicable basis.)

☐ Agreed lump sum price of ____________________

Or

☐ Actual incurred costs plus mark-up in accordance with the TERMS AND CONDITIONS in Section III, below.

III TERMS AND CONDITIONS Unless otherwise provided in Part II – Scope of Work of the Contract,

1. Labor shall be charged at actual cost, including all applicable Taxes, Insurance, Travel and Subsistence, and other applicable Fringe Benefits plus %
2. Equipment shall be charged at established rates for Owner equipment or at actual rates paid for hired units plus %
3. Materials shall be charged at actual cost, plus %
4. Subcontracts shall be charged at actual cost plus %

IV CONTRACTOR AUTHORIZATION TO PROCEED

We____
require and request, or understand and agree, that Owner is able to perform, or cause to be performed, the work described in the DESCRIPTION OF BACKCHARGE WORK section above and that we shall compensate Owner in accordance with the rates, prices, terms and conditions set forth herein.

CONTRACTOR (Signature)	TITLE	DATE

V. FINAL BACKCHARGE VALUE

Owner has performed, or caused to be performed; the work described herein and, in doing so, has incurred costs in the total amount of __ (as detailed in the supporting documentation) which shall be backcharged to the above named Contractor.

CONTRACTOR (Signature)	TITLE	DATE
OWNER (Signature)	TITLE	DATE

PART IV

SPECIFICATIONS

Part IV

Attachment A

Design Criteria Manual

Progress Energy

ENGINEERING SERVICES
CRYSTAL RIVER DISCHARGE CANAL COOLING STUDY
MASTER PROJ. NO. 200578849 / REQUEST NO. DH07-003

DESIGN CRITERIA MANUAL

FINAL ISSUE

S&L EVALUATION NO. 2008-11406, REV. 0

S&L PROJECT NUMBER 11550-028

JULY 31, 2008

SUBMITTED BY

Sargent & Lundy

PEF-POD4-00303

090007 Hearing Exhibit - 00002828

Part IV

Attachment B

Specification S2-A

Williamson, Judith

From: Grier III, Joseph J
Sent: Thursday, September 24, 2009 8:01 AM
To: Williamson, Judith
Cc: James, Philip
Subject: RE: T&M contracts

These are not T&M contracts. They are FIX contracts and NTE.
Thanks
Jody

From: Williamson, Judith
Sent: Thursday, September 24, 2009 6:51 AM
To: Grier III, Joseph J
Subject: T&M contracts

Good Morning, Jody,

Purchase Obligation reporting is due again early October. (For T&M contracts and purchase orders.)

Are Enercon, Transnuclear, and Morris Material Handling the only T&M contractors you have on SDF? Or have others been added since July reporting?

Thank you,
Judith

PEF-POD4-00306

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PEF's Responses to Staff's Fifth Request for Production of Documents (Nos. 16-17)

BEFORE THE PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause	Docket No. 090007-EI
	Dated: October 12, 2009

PROGRESS ENERGY FLORIDA'S RESPONSES TO STAFF'S FIFTH REQUEST FOR PRODUCTION OF DOCUMENTS (NOS. 16-17)

PROGRESS ENERGY FLORIDA, INC. ("PEF"), pursuant to Rule 28-106.206, Florida Administrative Code, Rule 1.350, Florida Rules of Civil Procedure, and the Order Establishing Procedure in this matter, hereby responds to Staff's Fifth Request for Production of Documents (Nos. 16-17):

RESPONSES

16. **Please provide revised Form 42-1P, Form 42-3P, Form 42-4P, and Capital Program Detail that are calculated based on the last Commission authorized Equity Component, Debt Component, and Depreciation rates.**

Response:

Please see attachment POD 16.1 – Revised Forms.

Projections Discovery - January 2010 through December 2010

17. **Please refer to the testimony and exhibits of Thomas G. Foster dated August 28, 2009. Please provide a schedule that shows the capital structure, components, and cost rates relied upon for calculating the revenue requirement rate of return. Please include in this schedule the derivation of debt and equity components used in the Return on Average Net Investment, lines 7 (a) and (b), on Form 42-4P. Please cite all sources and include the rationale for using the particular capital structure and cost rates.**

Response:

Please see attached POD 17.1 – Capital Structure, and Schedule D1-a, as filed in Docket 090079. This represents PEF's best estimate of the weighted average cost of capital (WACC) in 2010 at this time.

SERVED this 12th day of October, 2009.

HOPPING GREEN & SAMS, P.A.

By: Gary V. Perko

Gary V. Perko, Esquire
Florida Bar No. 855898
P.O. Box 6526
Tallahassee, FL 32301
(850) 222-7500

Attorneys for Progress Energy Florida, Inc.

Witness: T.G. Foster
POD 16.1

PROGRESS ENERGY FLORIDA, INC.
ENVIRONMENTAL COST RECOVERY
COMMISSION FORMS 42-1P, 42-3P & 42-4P

JANUARY 2010 - DECEMBER 2010
Calculation of the Projected Period Amount
January through December 2010
DOCKET NO. 090007-EI

PEF-POD5-00001

Form 42-1P

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to be Recovered
For the Projected Period
JANUARY 2010 - DECEMBER 2010
(in Dollars)

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)	$31,802,841	$725,908	$9,858,303	$4,532,180	$46,919,232
b	Projected Capital Projects (Form 42-3P, Lines 7 through 9)	181,450,067	0	7,189	2,327,033	183,784,289
c	Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b)	$213,252,908	$725,908	$9,865,492	$6,859,213	$230,703,521
2	True-up for Estimated Over/(Under) Recovery for the current period January 2009 - December 2009 (Form 42-2E, Line 5 + 6 + 10)	18,198,931	579,224	3,425,915	1,871,512	$24,075,581
3	Final True-up for the period January 2008 - December 2008 (Form 42-1A, Line 3)	(1,372,802)	(187,999)	(2,347,539)	(412,265)	($4,320,606)
4	Total Jurisdictional Amount to Be Recovered/(Refunded) in the Projection period January 2009 - December 2009 (Line 1 - Line 2 - Line 3)	$196,426,780	$334,683	$8,787,116	$5,399,967	$210,948,546
5	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier of 1.00072)	$196,568,207	$334,924	$8,793,443	$5,403,855	$211,100,429

Form 42-3P

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
Capital Investment Projects-Recoverable Costs
(in Dollars)

Line	Description	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	End of Period Total
1	Description of Investment Projects (A)													
3.1	Pipeline Integrity Management - Bartow/Anclote Pipeline-Intermediate	$47,949	$47,814	$47,682	$47,548	$47,413	$47,279	$47,144	$47,010	$46,876	$46,742	$46,607	$45,472	$566,536
4.1	Above Ground Tank Secondary Containment - Peaking	125,753	127,814	133,267	136,535	136,273	136,005	135,736	135,470	135,205	134,940	134,673	134,405	1,606,076
4.2	Above Ground Tank Secondary Containment - Base	28,702	28,646	28,593	28,539	28,485	28,432	28,377	28,323	28,268	28,214	28,161	28,107	340,847
4.3	Above Ground Tank Secondary Containment - Intermediate	3,924	3,916	3,906	3,898	3,889	3,880	3,871	3,862	3,853	3,845	3,835	3,827	46,506
5	SO2/NOX Emissions Allowances - Energy	361,837	352,664	345,676	338,992	328,652	315,311	303,075	290,963	279,186	270,013	263,580	257,921	3,707,870
7.1	CAIR Anclote- Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0
7.2	CAIR CT's - Peaking	25,301	25,259	25,219	25,179	25,140	25,098	25,059	25,020	24,978	24,936	24,900	24,856	300,945
7.3	CAIR Crystal River - Base	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	38,160
7.4	CAIR Crystal River AFUDC - Base	14,076,908	13,910,888	13,926,114	13,924,551	15,786,708	17,446,147	17,469,049	17,464,321	17,439,277	17,412,498	17,365,598	17,358,679	193[illegible]36
7.4	CAIR Crystal River AFUDC - Energy	8,150	8,291	8,291	8,291	8,291	8,291	8,291	8,291	8,291	8,291	8,291	8,291	[illegible]18
9	Sea Turtle - Coastal Street Lighting -Distribution	470	487	517	544	561	590	617	633	664	689	706	737	7,215
10.1	Underground Storage Tanks-Base	2,310	2,304	2,299	2,295	2,289	2,284	2,279	2,274	2,269	2,264	2,259	2,253	27,379
10.2	Underground Storage Tanks-Intermediate	1,016	1,014	1,011	1,010	1,007	1,005	1,003	1,000	998	995	993	992	12,045
11	Modular Cooling Towers - Base	13,893	13,771	13,649	13,528	13,406	13,284	13,162	13,040	12,918	12,796	12,674	12,552	158,673
11.1	Crystal River Thermal Discharge Compliance Project - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Total Investment Projects - Recoverable Costs	14,699,393	14,526,046	14,539,404	14,534,090	16,365,294	18,032,789	18,040,843	18,023,387	17,985,983	17,949,404	17,915,455	17,882,272	200,514,336
3	Recoverable Costs Allocated to Energy	369,987	360,955	353,967	347,283	336,943	323,602	311,366	299,254	287,477	278,304	271,871	266,212	3,807,218
	Recoverable Costs Allocated to Demand - Distribution	470	487	517	544	561	590	617	633	664	689	706	737	7,215
4	Recoverable Costs Allocated to Demand - Production - Base	14,124,993	13,958,789	13,973,835	13,972,093	15,834,068	17,495,327	17,516,047	17,511,138	17,485,912	17,458,952	17,431,870	17,404,771	194,167,795
	Recoverable Costs Allocated to Demand - Production - Intermediate	52,889	52,744	52,599	52,456	52,309	52,164	52,018	51,872	51,727	51,583	51,435	51,291	625,087
	Recoverable Costs Allocated to Demand - Production - Peaking	151,054	153,073	158,486	161,714	161,413	161,103	160,795	160,490	160,183	159,876	159,573	159,261	1,907,021
5	Retail Energy Jurisdictional Factor	0.96780	0.96220	0.96630	0.96650	0.96760	0.96960	0.96030	0.95790	0.95750	0.95620	0.95590	0.95990	
	Retail Distribution Demand Jurisdictional Factor	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	
6	Retail Demand Jurisdictional Factor - Production - Base	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	
	Retail Demand Jurisdictional Factor - Production - Intermediate	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	
	Retail Demand Jurisdictional Factor - Production - Peaking	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	
7	Jurisdictional Energy Recoverable Costs (B)	358,074	347,311	342,038	335,649	326,093	313,764	299,005	286,655	275,259	266,114	259,881	255,537	3,665,379
	Jurisdictional Demand Recoverable Costs - Distribution (B)	468	485	515	542	559	588	615	631	662	686	703	734	7,189
8	Jurisdictional Demand Recoverable Costs - Production - Base (C)	12,948,240	12,795,882	12,809,675	12,808,078	14,514,932	16,037,791	16,056,785	16,052,285	16,029,161	16,004,447	15,979,621	15,954,780	177,[illegible]6
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	31,391	31,305	31,219	31,134	31,046	30,960	30,874	30,787	30,701	30,616	30,528	30,442	[illegible]2
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	138,541	140,392	145,357	148,318	148,042	147,757	147,475	147,195	146,913	146,632	146,354	146,066	1,749,043
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$13,476,713	$13,315,375	$13,328,604	$13,323,720	$15,020,672	$16,530,861	$16,534,763	$16,517,553	$16,482,696	$16,448,495	$16,417,087	$16,387,561	$183,764,289

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

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
Return on Capital Investments, Depreciation and Taxes
For Project: PIPELINE INTEGRITY MANAGEMENT - Bartow/Anclote Pipeline (Project 3.1)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	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		$3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	
3	Less: Accumulated Depreciation		(565,408)	(577,610)	(589,812)	(602,014)	(614,216)	(626,418)	(638,620)	(650,822)	(663,024)	(675,226)	(687,428)	(699,630)	(711,832)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$3,014,328	3,002,126	2,989,924	2,977,722	2,965,520	2,953,318	2,941,116	2,928,914	2,916,712	2,904,510	2,892,308	2,880,106	2,867,904	
6	Average Net Investment			3,008,227	2,996,025	2,983,823	2,971,621	2,959,419	2,947,217	2,935,015	2,922,813	2,910,611	2,898,409	2,886,207	2,874,005	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		27,976	27,862	27,750	27,637	27,523	27,409	27,295	27,183	27,069	26,955	26,841	26,727	328,227
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		5,114	5,093	5,073	5,052	5,031	5,011	4,990	4,969	4,948	4,928	4,907	4,886	60,001
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			12,202	12,202	12,202	12,202	12,202	12,202	12,202	12,202	12,202	12,202	12,202	12,202	146,424
	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)			2,657	2,657	2,657	2,657	2,657	2,657	2,657	2,657	2,657	2,657	2,657	2,657	31,884
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			47,949	47,814	47,682	47,548	47,413	47,279	47,144	47,010	46,876	46,742	46,607	46,472	566,536
	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			47,949	47,814	47,682	47,548	47,413	47,279	47,144	47,010	46,876	46,742	46,607	46,472	566,536
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)			0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352
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)			28,459	28,379	28,300	28,221	28,141	28,061	27,981	27,901	27,822	27,742	27,662	27,582	336,250
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$28,459	$28,379	$28,300	$28,221	$28,141	$28,061	$27,981	$27,901	$27,822	$27,742	$27,662	$27,582	$336,250

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) Depreciation calculated in Pipeline Integrity Management section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI
(D) Lines 2 x 89% @ .009130 x 1/12 + 11% @ .007100 x 1/12. Ratio from Property Tax Administration Department, based on plant allocation reported and 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

090007 Hearing Exhibit - 00002838

PEF-POD5-00004

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - PEAKING (Project 4.1)
(in Dollars)

Form 42-4P

Line	Description		Beginning of Period Amount	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$155,000	$260,000	$223,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$638,000
	b. Clearings to Plant			0	0	1,513,040	0	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		$8,575,395	$8,575,395	$8,575,395	$10,088,435	$10,088,435	$10,088,435	$10,088,435	$10,088,435	$10,088,435	$10,088,435	$10,088,435	$10,088,435	$10,088,435	
3	Less: Accumulated Depreciation		(484,182)	(504,240)	(524,298)	(546,230)	(570,461)	(594,692)	(618,923)	(643,154)	(667,385)	(691,616)	(715,847)	(740,078)	(764,309)	
4	CWIP - Non-Interest Bearing		875,039	1,030,040	1,290,040	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$8,966,252	$9,101,195	$9,341,137	$9,542,204	$9,517,973	$9,493,742	$9,469,511	$9,446,280	$9,421,049	$9,396,818	$9,372,587	$9,348,356	$9,324,125	
6	Average Net Investment			$9,033,724	$9,221,166	$9,441,670	$9,530,089	$9,505,858	$9,481,627	$9,457,396	$9,433,166	$9,408,934	$9,384,703	$9,360,472	$9,336,241	0
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		84,014	85,756	87,808	88,629	88,405	88,180	87,954	87,727	87,502	87,279	87,054	86,828	1,047,136
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		15,357	15,676	16,051	16,200	16,162	16,119	16,076	16,037	15,997	15,955	15,913	15,871	191,414
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			20,058	20,058	21,933	24,231	24,231	24,231	24,231	24,231	24,231	24,231	24,231	24,231	280,126
	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)			6,324	6,324	7,475	7,475	7,475	7,475	7,475	7,476	7,475	7,475	7,475	7,475	87,368
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			125,753	127,814	133,267	136,535	136,273	136,005	135,736	135,470	135,205	134,940	134,673	134,405	1,606,076
	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			125,753	127,814	133,267	136,535	136,273	136,005	135,736	135,470	135,205	134,940	134,673	134,405	1,606,076
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)			0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	
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)			115,336	117,226	122,227	125,224	124,984	124,738	124,492	124,248	124,005	123,762	123,517	123,271	1,473,029
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$115,336	$117,226	$122,227	$125,224	$124,984	$124,738	$124,492	$124,248	$124,005	$123,762	$123,517	$123,271	$1,473,029

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) Depreciation calculated in Pipeline Integrity Management section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

090007 Hearing Exhibit - 00002839

PEF-POD5-00005

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
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 - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	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		$2,068,790	$2,068,790	$2,068,790	$2,068,790	$2,068,790	$2,068,790	$2,068,790	$2,068,790	$2,068,790	$2,068,790	$2,068,790	$2,068,790	$2,068,790	
3	Less: Accumulated Depreciation		(67,969)	(72,881)	(77,793)	(82,705)	(87,617)	(92,529)	(97,441)	(102,353)	(107,265)	(112,177)	(117,089)	(122,001)	(126,913)	
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)		2,000,821	1,995,909	1,990,997	1,986,085	1,981,173	1,976,261	1,971,349	1,966,437	1,961,525	1,956,613	1,951,701	1,946,789	1,941,877	
6	Average Net Investment			$1,998,365	$1,993,453	$1,988,541	$1,983,629	$1,978,717	$1,973,805	$1,968,893	$1,963,981	$1,959,069	$1,954,157	$1,949,245	$1,944,333	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		$18,585	$18,539	$18,494	$18,448	$18,402	$18,357	$18,311	$18,266	$18,219	$18,173	$18,128	$18,082	$220,004
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		$3,398	$3,388	$3,380	$3,372	$3,364	$3,356	$3,347	$3,338	$3,330	$3,322	$3,314	$3,306	$40,215
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			$4,912	$4,912	$4,912	$4,912	$4,912	$4,912	$4,912	$4,912	$4,912	$4,912	$4,912	$4,912	$58,944
	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)			1,807	1,807	1,807	1,807	1,807	1,807	1,807	1,807	1,807	1,807	1,807	1,807	21,684
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			28,702	28,646	28,593	28,539	28,485	28,432	28,377	28,323	28,268	28,214	28,161	28,107	340,847
	a. Recoverable Costs Allocated to Energy			-	-	-	-	-	-	-	-	-	-	-	-	-
	b. Recoverable Costs Allocated to Demand			28,702	28,646	28,593	28,539	28,485	28,432	28,377	28,323	28,268	28,214	28,161	28,107	340,847
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)			0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	
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)			26,311	26,260	26,211	26,161	26,112	26,063	26,013	25,963	25,913	25,863	25,815	25,765	312,451
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$26,311	$26,260	$26,211	$26,161	$26,112	$26,063	$26,013	$25,963	$25,913	$25,863	$25,815	$25,765	$312,451

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) Depreciation calculated in Pipeline Integrity Management section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
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 - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	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		$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	
3	Less: Accumulated Depreciation		(22,218)	(23,026)	(23,834)	(24,642)	(25,450)	(26,258)	(27,066)	(27,874)	(28,682)	(29,490)	(30,298)	(31,106)	(31,914)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$268,080	267,272	266,464	265,656	264,848	264,040	263,232	262,424	261,616	260,808	260,000	259,192	258,384	
6	Average Net Investment			267,676	266,868	266,060	265,252	264,444	263,636	262,828	262,020	261,212	260,404	259,596	258,788	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		2,489	2,482	2,474	2,467	2,459	2,452	2,444	2,437	2,429	2,422	2,414	2,407	29,376
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		455	454	452	451	450	448	447	445	444	443	441	440	5,370
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			808	808	808	808	808	808	808	808	808	808	808	808	9,696
	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)			172	172	172	172	172	172	172	172	172	172	172	172	2,064
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			3,924	3,916	3,906	3,898	3,889	3,880	3,871	3,862	3,853	3,845	3,835	3,827	46,506
	a. Recoverable Costs Allocated to Energy			-	-	-	-	-	-	-	-	-	-	-	-	-
	b. Recoverable Costs Allocated to Demand			3,924	3,916	3,906	3,898	3,889	3,880	3,871	3,862	3,853	3,845	3,835	3,827	46,506
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)			0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	
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	2,318	2,314	2,308	2,303	2,298	2,292	2,287	2,282	2,276	2,271	27,602
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$2,329	$2,324	$2,318	$2,314	$2,308	$2,303	$2,298	$2,292	$2,287	$2,282	$2,276	$2,271	$27,602

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 6.86%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2005 rate case settlement in Dkt. 050078-EI.
(C) Depreciation calculated in Pipeline Integrity Management section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
Schedule of Amortization and Return
Deferred Gain on Sales of Emissions Allowances (Project 8)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	Period Total
1	Working Capital Dr (Cr)															
	a. 1581001 SO_2 Emission Allowance Inventory		$6,902,143	$6,745,933	$6,636,274	$6,533,551	$6,426,299	$6,218,410	$6,078,016	$5,936,225	$5,770,051	$5,618,183	$5,504,402	$5,419,997	$5,333,889	$5,333,889
	b. 25401FL Auctioned SO_2 Allowance		(1,921,713)	(1,909,321)	(1,896,928)	(1,884,535)	(1,872,142)	(1,832,888)	(1,815,124)	(1,797,359)	(1,779,594)	(1,761,829)	(1,744,064)	(1,726,299)	(1,708,534)	(1,708,534)
	c. 1581002 NOX Emission Allowance Inventory		28,412,468	27,559,022	26,985,669	26,476,134	25,955,456	24,859,622	23,821,302	22,881,491	21,891,508	21,022,672	20,453,877	20,015,758	19,559,912	19,559,912
2	Total Working Capital		$33,392,897	32,395,634	31,725,015	31,125,149	30,509,612	29,245,143	28,084,194	27,020,358	25,881,966	24,879,026	24,214,216	23,709,457	23,185,267	23,185,267
3	Average Net Investment			32,894,266	32,060,325	31,425,082	30,817,381	29,877,378	28,664,669	27,552,276	26,451,162	25,380,496	24,546,621	23,961,836	23,447,362	
4	Return on Average Net Working Capital Balance															
	a. Equity Component Grossed Up For Taxes (A)	11.16%		305,917	298,181	292,253	286,602	277,880	266,581	256,236	245,996	236,039	228,284	222,845	218,060	$3,134,834
	b. Debt Component (Line 3 x 2.04% x 1/12)	2.04%		55,920	54,503	53,423	52,390	50,792	48,730	46,839	44,967	43,147	41,729	40,735	39,861	573,036
5	Total Return Component (B)			361,837	352,684	345,676	338,992	328,652	315,311	303,075	290,963	279,186	270,013	263,580	257,921	3,707,870
6	Expense Dr (Cr)															
	a. 5090001 SO_2 allowance expense			$156,210	$109,658	$102,724	$107,252	$207,869	$140,394	$141,791	$166,174	$151,869	$113,780	$84,405	$86,108	1,568,253
	b. 4074004 Amortization Expense			(12,393)	(12,393)	(12,393)	(12,393)	(39,254)	(17,765)	(17,765)	(17,765)	(17,765)	(17,765)	(17,765)	(17,765)	($213,180)
	c. 5090003 Nox allowance expense			853,446	573,354	509,535	520,678	1,095,834	1,038,320	959,811	989,983	868,836	568,796	438,119	455,846	$8,852,556
7	Net Expense (C)			997,263	670,619	599,866	615,537	1,264,469	1,160,949	1,083,837	1,138,392	1,002,939	664,810	504,759	524,189	10,207,630
8	Total System Recoverable Expenses (Lines 5 + 7)			1,359,100	1,023,283	945,542	954,529	1,593,121	1,476,260	1,386,912	1,429,355	1,282,125	934,823	768,339	782,110	13,915,500
	a. Recoverable costs allocated to Energy			1,359,100	1,023,283	945,542	954,529	1,593,121	1,476,260	1,386,912	1,429,355	1,282,125	934,823	768,339	782,110	13,915,500
	b. Recoverable costs allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor			0.96780	0.96220	0.96630	0.96650	0.96780	0.96960	0.96030	0.95790	0.95750	0.95620	0.95590	0.95990	
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)			1,315,337	984,603	913,677	922,553	1,541,822	1,431,361	1,312,645	1,369,179	1,227,635	893,878	734,456	750,748	13,397,914
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)			$ 1,315,337	$ 984,603	$ 913,677	$ 922,553	$ 1,541,822	$ 1,431,361	$ 1,312,645	$ 1,369,179	$ 1,227,635	$ 893,878	$ 734,456	$ 750,748	$ 13,397,914

Notes:
(A) 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.
(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.

090007 Hearing Exhibit - 00002842

PEF-POD5-00008

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
Return on Capital Investments, Depreciation and Taxes
For Project: CAIR - Intermediate (Project 7.1 - Anclote Low Nox Burners and SOFA)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	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 2.57% x 1/12)	2.04%		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Other			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			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	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 (Intm)			0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	
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 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

090007 Hearing Exhibit - 00002843

PEF-POD5-00009

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
Return on Capital Investments, Depreciation and Taxes
For Project: CAIR - Peaking (Project 7.2 - CT Emission Monitoring Systems)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	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		$1,934,400	$1,934,400	$1,934,400	$1,934,400	$1,934,400	$1,934,400	$1,934,400	$1,934,400	$1,934,400	$1,934,400	$1,934,400	$1,934,400	$1,934,400	
3	Less: Accumulated Depreciation		(91,024)	(94,679)	(98,334)	(101,989)	(105,644)	(109,299)	(112,954)	(116,609)	(120,264)	(123,919)	(127,574)	(131,229)	(134,884)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$1,843,377	1,839,722	1,836,067	1,832,412	1,828,757	1,825,102	1,821,447	1,817,792	1,814,137	1,810,482	1,806,827	1,803,172	1,799,517	
6	Average Net Investment			1,841,550	1,837,895	1,834,240	1,830,585	1,826,930	1,823,275	1,819,620	1,815,965	1,812,310	1,808,655	1,805,000	1,801,345	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		17,127	17,092	17,058	17,023	16,991	16,956	16,923	16,890	16,854	16,819	16,787	16,751	203,271
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		3,131	3,124	3,118	3,113	3,106	3,099	3,093	3,087	3,081	3,074	3,070	3,062	37,158
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			3,655	3,655	3,655	3,655	3,655	3,655	3,655	3,655	3,655	3,655	3,655	3,655	43,860
	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)			1,388	1,388	1,388	1,388	1,388	1,388	1,388	1,388	1,388	1,388	1,388	1,388	16,656
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			25,301	25,259	25,219	25,179	25,140	25,098	25,059	25,020	24,978	24,936	24,900	24,856	300,945
	a. Recoverable Costs Allocated to Energy			-	-	-	-	-	-	-	-	-	-	-	-	-
	b. Recoverable Costs Allocated to Demand			25,301	25,259	25,219	25,179	25,140	25,098	25,059	25,020	24,978	24,936	24,900	24,856	300,945
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Peaking)			0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	
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)			23,205	23,167	23,130	23,093	23,057	23,019	22,983	22,947	22,909	22,870	22,837	22,797	276,015
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$23,205	$23,167	$23,130	$23,093	$23,057	$23,019	$22,983	$22,947	$22,909	$22,870	$22,837	$22,797	$276,015

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-EL
(C) Depreciation calculated in Pipeline Integrity Management section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EL
(D) Property tax calculated in CAIR CTs section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
Return on Capital Investments, Depreciation and Taxes
For Project: CAIR - Crystal River - Base (Project 7.3 - Continuous Mercury Monitoring Systems)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	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	
4	CWIP - Non-Interest Bearing		289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	
5	Net Investment (Lines 2 + 3 + 4)		$289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	
6	Average Net Investment			289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		2,689	2,689	2,689	2,689	2,689	2,689	2,689	2,689	2,689	2,689	2,689	2,689	$32,268
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		491	491	491	491	491	491	491	491	491	491	491	491	5,892
	c. Other			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			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)			3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	38,160
	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			3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	38,160
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)			0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	
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)			2,915	2,915	2,915	2,915	2,915	2,915	2,915	2,915	2,915	2,915	2,915	2,915	34,981
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$2,915	$2,915	$2,915	$2,915	$2,915	$2,915	$2,915	$2,915	$2,915	$2,915	$2,915	$2,915	$34,981

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 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

090007 Hearing Exhibit - 00002845

PEF-POD5-00011

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
Return on Capital Investments, Depreciation and Taxes
For Project: CAIR - Base - AFUDC (Project 7.4 - Crystal River FGD and SCR)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	End of Period Total
1	Investments															
	a. Expenditures/Additions			11,791,501	13,154,705	11,180,371	9,202,135	3,175,787	$3,433,939	$3,931,322	$689,781	$406,743	$387,177	$386,781	$386,665	$58,126,966
	b. Clearings to Plant			1,560,000	3,288,200	2,609,865	1,120,000	249,120,680	3,433,939	3,931,322	689,781	406,743	387,177	386,781	386,665	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)	7.867%		1,517,093	1,552,104	1,614,428	1,703,016	893,364	0	0	0	0	0	0	0	7,280,005
2	Plant-in-Service/Depreciation Base		$979,476,187	981,036,187	984,324,387	986,934,372	988,054,372	1,237,175,052	1,240,608,991	1,244,540,313	1,245,230,094	1,245,636,838	1,246,024,013	1,246,410,794	1,246,797,459	
3	Less: Accumulated Depreciation		($4,408,719)	(6,729,559)	(9,058,153)	(11,392,902)	(13,730,292)	(16,363,283)	(19,296,282)	(22,238,553)	(25,182,451)	(28,127,307)	(31,073,077)	(34,019,759)	(36,967,353)	
4	CWIP - AFUDC-Interest Bearing		201,914,362	213,662,956	225,061,565	235,266,379	245,051,530	0	0	0	0	0	0	0	0	65,406,911
5	Net Investment (Lines 2 + 3 + 4)		$1,176,981,830	1,187,969,563	1,200,347,799	1,210,807,848	1,219,375,609	1,220,811,770	1,221,312,710	1,222,301,761	1,220,047,644	1,217,509,530	1,214,950,937	1,212,391,035	1,209,830,107	
6	Average Net Investment			1,182,475,706	1,194,158,691	1,205,577,823	1,215,091,729	1,220,093,689	1,221,062,240	1,221,807,235	1,221,174,702	1,218,778,587	1,216,230,234	1,213,670,987	1,211,110,571	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		9,064,589	9,065,513	9,071,256	9,066,874	10,207,383	11,355,877	11,362,807	11,356,924	11,334,641	11,310,941	11,287,141	11,263,327	125,747,273
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		1,656,969	1,657,137	1,658,186	1,657,386	1,865,866	2,075,805	2,077,072	2,075,998	2,071,923	2,067,592	2,063,241	2,058,888	22,986,063
	c. Other (C)			114,545	0	0	0	0	0	0	0	0	0	0	0	114,545
8	Investment Expenses															
	a. Depreciation (D)			2,320,840	2,328,594	2,334,749	2,337,390	2,632,991	2,932,999	2,942,271	2,943,898	2,944,856	2,945,770	2,946,682	2,947,594	32,558,634
	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 (E)			856,772	859,644	861,923	862,901	1,080,467	1,083,469	1,086,899	1,087,501	1,087,857	1,088,195	1,088,532	1,088,870	12,133,027
	e. Other (F)			63,193	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			14,076,908	13,910,888	13,926,114	13,924,551	15,786,708	17,448,147	17,469,049	17,464,321	17,439,277	17,412,498	17,385,596	17,358,679	193,602,736
	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			14,076,908	13,910,888	13,926,114	13,924,551	15,786,708	17,448,147	17,469,049	17,464,321	17,439,277	17,412,498	17,385,596	17,358,679	193,602,736
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)			0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	
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			12,904,161	12,751,872	12,765,929	12,764,497	14,471,517	15,994,542	16,013,703	16,009,368	15,986,411	15,961,863	15,937,202	15,912,527	177,473,692
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$12,904,161	$12,751,872	$12,765,929	$12,764,497	$14,471,517	$15,994,542	$16,013,703	$16,009,368	$15,986,411	$15,961,863	$15,937,202	$15,912,527	$177,473,692

Notes:
(A) AFUDC calculation based on proposal in PEF's rate case Dkt. 090079-EI.
(B) Return on equity and debt calculated only on assets placed in service which appear in CAIR Crystal River AFUDC section of Capital Program Detail file. Calculated on that schedule as Line 6 x rate x 1/12. Rate 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) T/U amount for the equity and debt components of the average net investment that were inadvertantly excluded in the 2009 Est/Actual filing.
(D) Depreciation calculated only on assets placed inservice which appear in CAIR Crystal River AFUDC section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(E) Property taxes calculated only on assets placed in-service which appear in CAIR Crystal River AFUDC section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.
(F) T/U amount for depreciation and property tax expenses that were inadvertantly excluded in the 2009 Est/Actual filing.

090007 Hearing Exhibit - 00002846

PEF-POD5-00012

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
JANUARY 2010 - DECEMBER 2010

Schedule of Amortization and Return
For Project: CAIR - Energy - AFUDC (Project 7.4 - Reagents and By-products)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual Jan - 10	Actual Feb - 10	Actual Mar - 10	Actual Apr - 10	Actual May - 10	Actual Jun - 10	Estimated Jul - 10	Estimated Aug - 10	Estimated Sep - 10	Estimated Oct - 10	Estimated Nov - 10	Estimated Dec - 10	End of Period Total
1	Working Capital Dr (Cr)															
	a. 1544001 Ammonia Inventory		$158,148	$164,105	$164,105	$164,105	$164,105	$164,105	$164,105	$164,105	$164,105	$164,105	$164,105	$164,105	$164,105	$164,105
	b. 1544004 Limestone Inventory		570,000	589,600	589,600	589,600	589,600	589,600	589,600	589,600	589,600	589,600	589,600	589,600	589,600	589,600
2	Total Working Capital		$728,148	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705
3	Average Net Investment			740,926	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705	
4	Return on Average Net Working Capital Balance															
	a. Equity Component Grossed Up For Taxes (A)	11.16%		6,891	7,009	7,009	7,009	7,009	7,009	7,009	7,009	7,009	7,009	7,009	7,009	$83,995
	b. Debt Component (Line 3 x 2.04% x 1/12)	2.04%		1,260	1,281	1,281	1,281	1,281	1,281	1,281	1,281	1,281	1,281	1,281	1,281	15,354
5	Total Return Component (B)			8,150	8,291	8,291	8,291	8,291	8,291	8,291	8,291	8,291	8,291	8,291	8,291	99,348
6	Expense Dr (Cr)															
	a. 5020011 Ammonia expense			253,398	218,073	257,348	236,362	202,109	530,288	514,636	567,914	535,720	535,485	436,209	566,378	4,852,920
	c. 5020012 Limestone Expense			58,148	50,765	124,613	114,176	74,193	195,891	190,429	311,904	304,004	302,984	238,229	327,001	2,292,336
	d. 5020003 Gypsum Disposal/Sale			380,324	359,321	569,399	539,709	425,968	772,168	756,630	1,102,194	1,079,720	1,076,818	892,608	1,145,142	9,100,000
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
7	Net Expense (C)			691,870	628,160	951,359	890,247	702,271	1,498,347	1,461,695	1,982,012	1,919,443	1,915,287	1,567,046	2,037,521	16,245,257
8	Total System Recoverable Expenses (Lines 5 + 7)			700,020	636,451	959,650	898,538	710,561	1,506,638	1,469,986	1,990,303	1,927,734	1,923,578	1,575,337	2,045,811	16,344,605
	a. Recoverable costs allocated to Energy			700,020	636,451	959,650	898,538	710,561	1,506,638	1,469,986	1,990,303	1,927,734	1,923,578	1,575,337	2,045,811	16,344,605
	b. Recoverable costs allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor			0.96780	0.96220	0.96630	0.96650	0.96780	0.96960	0.96030	0.95790	0.95750	0.95620	0.95590	0.95990	
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)			677,479	612,393	927,310	868,437	687,681	1,460,836	1,411,628	1,906,511	1,845,805	1,839,325	1,505,864	1,963,774	15,707,043
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)			$ 677,479	$ 612,393	$ 927,310	$ 868,437	$ 687,681	$ 1,460,836	$ 1,411,628	$ 1,906,511	$ 1,845,805	$ 1,839,325	$ 1,505,864	$ 1,963,774	$ 15,707,043

Notes:
(A) 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.
(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 Projected Period Amount
JANUARY 2010 - DECEMBER 2010
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 - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	End of Period Total
1	Investments														
	a. Expenditures/Additions		1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	$20,000
	b. Clearings to Plant		0	0	5,000	0	0	5,000	0	0	5,000	0	0	5,000	
	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	$30,146	30,146	30,146	35,146	35,146	35,146	40,146	40,146	40,146	45,146	45,146	45,146	50,146	
3	Less: Accumulated Depreciation	(852)	(967)	(1,082)	(1,207)	(1,341)	(1,475)	(1,618)	(1,772)	(1,926)	(2,090)	(2,263)	(2,436)	(2,618)	
4	CWIP - Non-Interest Bearing	-	1,667	3,333	(0)	1,667	3,333	(0)	1,667	3,333	(0)	1,667	3,333	(0)	
5	Net Investment (Lines 2 + 3 + 4)	$29,294	30,846	32,397	33,939	35,472	37,005	38,528	40,041	41,553	43,056	44,550	46,044	47,528	
6	Average Net Investment		30,070	31,621	33,168	34,706	36,238	37,766	39,284	40,797	42,305	43,803	45,297	46,786	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		280	294	308	323	337	351	365	379	393	407	421	435	$4,293
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		51	54	56	59	62	64	67	69	72	74	77	80	785
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation (C) 4.59%		115	115	125	134	134	144	154	154	164	173	173	183	1,766
	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 (D) 0.009400		24	24	28	28	28	31	31	31	35	35	35	39	369
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		470	487	517	544	561	590	617	633	664	689	706	737	7,216
	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		470	487	517	544	561	590	617	633	664	689	706	737	7,216
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)		0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	
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)		468	485	515	542	559	588	615	631	662	686	703	734	7,189
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$468	$485	$515	$542	$559	$588	$615	$631	$662	$686	$703	$734	$7,189

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 6.65%, 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

PEF-POD5-00014

090007 Hearing Exhibit - 00002848

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
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 - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	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		(14,032)	(14,492)	(14,952)	(15,412)	(15,872)	(16,332)	(16,792)	(17,252)	(17,712)	(18,172)	(18,632)	(19,092)	(19,552)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$154,909	154,449	153,989	153,529	153,069	152,609	152,149	151,689	151,229	150,769	150,309	149,849	149,389	
6	Average Net Investment			154,679	154,219	153,759	153,299	152,839	152,379	151,919	151,459	150,999	150,539	150,079	149,619	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		1,439	1,434	1,430	1,426	1,421	1,417	1,413	1,409	1,404	1,400	1,396	1,391	$16,980
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		263	262	261	261	260	259	258	257	257	256	255	254	3,103
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	3.27%		460	460	460	460	460	460	460	460	460	460	460	460	5,520
	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)	0.010480		148	148	148	148	148	148	148	148	148	148	148	148	1,776
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,310	2,304	2,299	2,295	2,289	2,284	2,279	2,274	2,269	2,264	2,259	2,253	27,379
	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			2,310	2,304	2,299	2,295	2,289	2,284	2,279	2,274	2,269	2,264	2,259	2,253	27,379
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)			0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	
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)			2,118	2,112	2,107	2,104	2,098	2,094	2,089	2,085	2,080	2,075	2,071	2,065	25,098
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$2,118	$2,112	$2,107	$2,104	$2,098	$2,094	$2,089	$2,085	$2,080	$2,075	$2,071	$2,065	$25,098

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 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

090007 Hearing Exhibit - 00002849

PEF-POD5-00015

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
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 - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	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		$76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	
3	*Less: Accumulated Depreciation*		(7,169)	(7,371)	(7,573)	(7,775)	(7,977)	(8,179)	(8,381)	(8,583)	(8,785)	(8,987)	(9,189)	(9,391)	(9,593)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$68,837	68,635	68,433	68,231	68,029	67,827	67,625	67,423	67,221	67,019	66,817	66,615	66,413	
6	Average Net Investment			68,736	68,534	68,332	68,130	67,928	67,726	67,524	67,322	67,120	66,918	66,716	66,514	
7	*Return on Average Net Investment*															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		639	637	635	634	632	630	628	626	624	622	620	619	$7,546
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		117	117	116	116	115	115	115	114	114	114	113	113	1,379
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	3.19%		202	202	202	202	202	202	202	202	202	202	202	202	2,424
	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)	0.009130		58	58	58	58	58	58	58	58	58	58	58	58	696
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	*Total System Recoverable Expenses (Lines 7 + 8)*			1,016	1,014	1,011	1,010	1,007	1,005	1,003	1,000	998	996	993	992	12,045
	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			1,016	1,014	1,011	1,010	1,007	1,005	1,003	1,000	998	996	993	992	12,045
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)			0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	
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)			603	602	600	599	598	596	595	594	592	591	589	589	7,149
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$603	$602	$600	$599	$598	$596	$595	$594	$592	$591	$589	$589	$7,149

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 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
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 - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	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		$665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	
3	Less: Accumulated Depreciation		(457,179)	(468,265)	(479,351)	(490,437)	(501,523)	(512,609)	(523,695)	(534,781)	(545,867)	(556,953)	(568,039)	(579,125)	(590,211)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$207,962	196,876	185,790	174,704	163,618	152,532	141,446	130,360	119,274	108,188	97,102	86,016	74,930	
6	Average Net Investment			202,419	191,333	180,247	169,161	158,075	146,989	135,903	124,817	113,731	102,645	91,559	80,473	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		1,882	1,779	1,676	1,573	1,470	1,367	1,264	1,161	1,058	955	851	748	$15,784
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		344	325	306	288	269	250	231	212	193	174	156	137	2,885
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	20.00%		11,086	11,086	11,086	11,086	11,086	11,086	11,086	11,086	11,086	11,086	11,086	11,086	133,032
	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)	0.010480		581	581	581	581	581	581	581	581	581	581	581	581	6,972
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			13,893	13,771	13,649	13,528	13,406	13,284	13,162	13,040	12,918	12,796	12,674	12,552	158,673
	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			13,893	13,771	13,649	13,528	13,406	13,284	13,162	13,040	12,918	12,796	12,674	12,552	158,673
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)			0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	
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)			12,736	12,624	12,512	12,401	12,289	12,177	12,065	11,954	11,842	11,730	11,618	11,506	145,454
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$12,736	$12,624	$12,512	$12,401	$12,289	$12,177	$12,065	$11,954	$11,842	$11,730	$11,618	$11,506	$145,454

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 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

090007 Hearing Exhibit - 00002851

PEF-POD5-00017

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
Return on Capital Investments, Depreciation and Taxes
For Project: Crystal River Thermal Discharge Compliance Project- AFUDC - Base (Project 11.1)
(in Dollars)

Line Description		Beginning of Period Amount	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	End of Period Total
1 Investments															
a. Expenditures/Additions			$1,868,181	$2,602,065	$1,862,773	$2,273,032	$2,588,045	$3,100,537	$4,668,022	$3,304,359	$5,473,948	$3,443,422	$1,740,138	$1,703,100	$34,627,623
b. Clearings to Plant			0	0	0	0	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)	7.867%		$ 81,939	$ 98,367	$ 114,892	$ 130,358	$ 148,525	$ 169,744	$ 198,487	$ 228,156	$ 260,893	$ 294,355	$ 314,817	$ 329,256	$2,369,796
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		$9,537,888	11,406,069	14,008,134	15,870,907	18,143,939	20,731,984	23,832,521	28,500,543	31,804,902	37,278,850	40,722,272	42,462,410	44,165,511	
5 *Net Investment (Lines 2 + 3 + 4)*		$0	11,406,069	14,008,134	15,870,907	18,143,939	20,731,984	23,832,521	28,500,543	31,804,902	37,278,850	40,722,272	42,462,410	44,165,511	
6 Average Net Investment			5,703,034	12,707,101	14,939,520	17,007,423	19,437,961	22,282,252	26,166,532	30,152,723	34,541,876	39,000,561	41,592,341	43,313,961	
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
c. *Other*			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)*			0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	
12 Retail Energy-Related Recoverable Costs (C)			0	0	0	0	0	0	0	0	0	0	0	0	0
13 Retail Demand-Related Recoverable Costs (D)			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) AFUDC calculation based on proposal in PEF's rate case Dkt. 090079-EI.
(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 9a x Line 10
(D) Line 9b x Line 11

090007 Hearing Exhibit - 00002852

PEF-POD5-00018

Witness: T.G. Foster
POD 16.1

PROGRESS ENERGY FLORIDA, INC.
ENVIRONMENTAL COST RECOVERY
REVISED CAPITAL PROGRAM DETAIL

JANUARY 2010 - DECEMBER 2010
Calculation of the Projected Period Amount
January through December 2010
DOCKET NO. 090007-EI

CPO

PEF-POD5-00020

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 3.1 Recap
JANUARY 2010 - DECEMBER 2010

For Project: PIPELINE INTEGRITY MANAGEMENT - Alderman Road Fence (Project 3.1a)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	
3	Less: Accumulated Depreciation		($5,497)	(5,584)	(5,671)	(5,758)	(5,845)	(5,932)	(6,019)	(6,106)	(6,193)	(6,280)	(6,367)	(6,454)	(6,541)	
4	CWIP - Non-Interest Bearing		$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$28,456	28,369	28,282	28,195	28,108	28,021	27,934	27,847	27,760	27,673	27,586	27,499	27,412	
6	Average Net Investment			28,412	28,325	28,238	28,151	28,064	27,977	27,890	27,803	27,716	27,629	27,542	27,455	
7	Return on Average Net Investment															
	a. *Equity Component Grossed Up For Taxes*	11.16%		264	263	263	262	261	260	259	259	258	257	256	255	$3,117
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		48	48	48	48	48	48	47	47	47	47	47	47	570
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.07%		87	87	87	87	87	87	87	87	87	87	87	87	1,044
	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	0.008907		25	25	25	25	25	25	25	25	25	25	25	25	300
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			424	423	423	422	421	420	418	418	417	416	415	414	5,031
	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			424	423	423	422	421	420	418	418	417	416	415	414	5,031

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Leak Detection (Project 3.1b)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	
3	Less: Accumulated Depreciation		($521,675)	(530,697)	(539,719)	(548,741)	(557,763)	(566,785)	(575,807)	(584,829)	(593,851)	(602,873)	(611,895)	(620,917)	(629,939)	
4	CWIP - Non-Interest Bearing		$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$2,118,961	2,109,939	2,100,917	2,091,895	2,082,873	2,073,851	2,064,829	2,055,807	2,046,785	2,037,763	2,028,741	2,019,719	2,010,697	
6	Average Net Investment			2,114,450	2,105,428	2,096,406	2,087,384	2,078,362	2,069,340	2,060,318	2,051,296	2,042,274	2,033,252	2,024,230	2,015,208	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		19,664	19,580	19,497	19,413	19,329	19,245	19,161	19,077	18,993	18,909	18,825	18,741	$230,434
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		3,595	3,579	3,564	3,548	3,533	3,518	3,503	3,487	3,472	3,457	3,441	3,426	42,124
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	4.10%		9,022	9,022	9,022	9,022	9,022	9,022	9,022	9,022	9,022	9,022	9,022	9,022	108,264
	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	0.008907		1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	23,520
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			34,241	34,141	34,043	33,944	33,844	33,745	33,646	33,546	33,447	33,348	33,248	33,149	404,342
	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			34,241	34,141	34,043	33,944	33,844	33,745	33,646	33,546	33,447	33,348	33,248	33,149	404,342

090007 Hearing Exhibit - 00002854

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 3.1 Recap
JANUARY 2010 - DECEMBER 2010

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Controls Upgrade (Project 3.1c)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$905,147	905,147	905,147	905,147	905,147	905,147	905,147	905,147	905,147	905,147	905,147	905,147	905,147	
3	Less: Accumulated Depreciation		($38,234)	(41,320)	(44,422)	(47,515)	(50,608)	(53,701)	(56,794)	(59,887)	(62,980)	(66,073)	(69,166)	(72,259)	(75,352)	
4	CWIP - Non-Interest Bearing		($0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$866,911	863,818	860,725	857,632	854,539	851,446	848,353	845,260	842,167	839,074	835,981	832,888	829,795	
6	Average Net Investment			865,365	862,272	859,179	856,086	852,993	849,900	846,807	843,714	840,621	837,528	834,435	831,342	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.18%		8,048	8,019	7,990	7,962	7,933	7,904	7,875	7,847	7,818	7,789	7,760	7,731	$94,676
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		1,471	1,466	1,461	1,455	1,450	1,445	1,440	1,434	1,429	1,424	1,419	1,413	17,307
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	4.10%		3,093	3,093	3,093	3,093	3,093	3,093	3,093	3,093	3,093	3,093	3,093	3,093	37,116
	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	0.008907		672	672	672	672	672	672	672	672	672	672	672	672	8,064
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			13,284	13,250	13,216	13,182	13,148	13,114	13,080	13,046	13,012	12,978	12,944	12,909	157,163
	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			13,284	13,250	13,216	13,182	13,148	13,114	13,080	13,046	13,012	12,978	12,944	12,909	157,163

CPD

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
JANUARY 2010 - DECEMBER 2010

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 1 & 2 (Project 4.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		(8,547)	(8,658)	(8,769)	(8,880)	(8,991)	(9,102)	(9,213)	(9,324)	(9,435)	(9,546)	(9,657)	(9,768)	(9,879)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$24,545	24,434	24,323	24,212	24,101	23,990	23,879	23,768	23,657	23,546	23,435	23,324	23,213	
6	Average Net Investment			24,489	24,378	24,267	24,156	24,045	23,934	23,823	23,712	23,601	23,490	23,379	23,268	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		228	227	226	225	224	223	222	221	219	218	217	216	$2,666
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		42	41	41	41	41	41	40	40	40	40	40	40	487
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	4.03%		111	111	111	111	111	111	111	111	111	111	111	111	1,332
	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	0.010480		29	29	29	29	29	29	29	29	29	29	29	29	348
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			410	408	407	406	405	404	402	401	399	398	397	396	4,833
	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			410	408	407	406	405	404	402	401	399	398	397	396	4,833

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - INTERCESSION CITY CTs (Project 4.1c)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	
3	Less: Accumulated Depreciation		(176,123)	(180,817)	(185,511)	(190,205)	(194,899)	(199,593)	(204,287)	(208,981)	(213,675)	(218,369)	(223,063)	(227,757)	(232,451)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$1,485,541	1,480,847	1,476,153	1,471,459	1,466,765	1,462,071	1,457,377	1,452,683	1,447,989	1,443,295	1,438,601	1,433,907	1,429,213	
6	Average Net Investment			1,483,194	1,478,500	1,473,806	1,469,112	1,464,418	1,459,724	1,455,030	1,450,336	1,445,642	1,440,948	1,436,254	1,431,560	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		13,794	13,750	13,706	13,663	13,619	13,575	13,532	13,488	13,444	13,401	13,357	13,314	$162,643
	b. Debt Component (Line 6 x 2.67% x 1/12)	2.04%		2,521	2,513	2,505	2,497	2,490	2,482	2,474	2,466	2,458	2,450	2,442	2,434	29,732
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.39%		4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	56,328
	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	0.007740		1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	12,864
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			22,081	22,029	21,977	21,926	21,875	21,823	21,772	21,720	21,668	21,617	21,565	21,514	261,567
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			22,081	22,029	21,977	21,926	21,875	21,823	21,772	21,720	21,668	21,617	21,565	21,514	261,567

090007 Hearing Exhibit - 00002856

PEF-POD5-00023

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
JANUARY 2010 - DECEMBER 2010

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - AVON PARK CTs (Project 4.1d)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		(21,161)	(21,681)	(22,201)	(22,721)	(23,241)	(23,761)	(24,281)	(24,801)	(25,321)	(25,841)	(26,361)	(26,881)	(27,401)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$157,777	157,257	156,737	156,217	155,697	155,177	154,657	154,137	153,617	153,097	152,577	152,057	151,537	
6	Average Net Investment			157,517	156,997	156,477	155,957	155,437	154,917	154,397	153,877	153,357	152,837	152,317	151,797	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.19%		1,465	1,460	1,455	1,450	1,446	1,441	1,436	1,431	1,426	1,421	1,417	1,412	$17,260
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		268	267	266	265	264	263	262	262	261	260	259	258	3,155
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.49%		520	520	520	520	520	520	520	520	520	520	520	520	6,240
	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	0.008760		131	131	131	131	131	131	131	131	131	131	131	131	1,572
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,384	2,378	2,372	2,366	2,361	2,355	2,349	2,344	2,338	2,332	2,327	2,321	28,227
	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			2,384	2,378	2,372	2,366	2,361	2,355	2,349	2,344	2,338	2,332	2,327	2,321	28,227

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BAYBORO CTs (Project 4.1e)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$730,296	730,296	730,296	730,296	730,296	730,296	730,296	730,296	730,296	730,296	730,296	730,296	730,296	
3	Less: Accumulated Depreciation		(45,596)	(47,215)	(48,834)	(50,453)	(52,072)	(53,691)	(55,310)	(56,929)	(58,548)	(60,167)	(61,786)	(63,405)	(65,024)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$684,699	683,081	681,462	679,843	678,224	676,605	674,986	673,367	671,748	670,129	668,510	666,891	665,272	
6	Average Net Investment			683,890	682,271	680,652	679,033	677,414	675,795	674,176	672,557	670,938	669,319	667,700	666,081	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.19%		6,360	6,345	6,330	6,315	6,300	6,285	6,270	6,255	6,240	6,225	6,210	6,195	$75,330
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		1,163	1,160	1,157	1,154	1,152	1,149	1,146	1,143	1,141	1,138	1,135	1,132	13,770
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.66%		1,619	1,619	1,619	1,619	1,619	1,619	1,619	1,619	1,619	1,619	1,619	1,619	19,428
	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	0.009130		556	556	556	556	556	556	556	556	556	556	556	556	6,672
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			9,698	9,680	9,662	9,644	9,627	9,609	9,591	9,573	9,556	9,538	9,520	9,502	115,200
	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			9,698	9,680	9,662	9,644	9,627	9,609	9,591	9,573	9,556	9,538	9,520	9,502	115,200

PEF-POD5-00024

090007 Hearing Exhibit - 00002857

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
JANUARY 2010 - DECEMBER 2010

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - SUWANNEE CTs (Project 4.1f)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	
3	Less: Accumulated Depreciation		(84,360)	(87,126)	(89,892)	(92,658)	(95,424)	(98,190)	(100,956)	(103,722)	(106,488)	(109,254)	(112,020)	(114,786)	(117,552)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$952,839	950,073	947,307	944,541	941,775	939,009	936,243	933,477	930,711	927,945	925,179	922,413	919,647	
6	Average Net Investment			951,456	948,690	945,924	943,158	940,392	937,626	934,860	932,094	929,328	926,562	923,796	921,030	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		8,849	8,823	8,797	8,771	8,746	8,720	8,694	8,668	8,643	8,617	8,591	8,566	$104,485
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		1,617	1,613	1,608	1,603	1,599	1,594	1,589	1,585	1,580	1,575	1,570	1,566	19,099
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.20%		2,766	2,766	2,766	2,766	2,766	2,766	2,766	2,766	2,766	2,766	2,766	2,766	33,192
	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	0.007850		679	679	679	679	679	679	679	679	679	679	679	679	8,148
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			13,911	13,881	13,850	13,819	13,790	13,759	13,728	13,698	13,668	13,637	13,606	13,577	164,924
	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			13,911	13,881	13,850	13,819	13,790	13,759	13,728	13,698	13,668	13,637	13,606	13,577	164,924

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - DeBARY CTs (Project 4.1g)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	
3	Less: Accumulated Depreciation		(37,782)	(42,391)	(47,000)	(51,609)	(56,218)	(60,827)	(65,436)	(70,045)	(74,654)	(79,263)	(83,872)	(88,481)	(93,090)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$2,335,991	2,331,382	2,326,773	2,322,164	2,317,555	2,312,946	2,308,337	2,303,728	2,299,119	2,294,510	2,289,901	2,285,292	2,280,683	
6	Average Net Investment			2,333,687	2,329,078	2,324,469	2,319,860	2,315,251	2,310,642	2,306,033	2,301,424	2,296,815	2,292,206	2,287,597	2,282,988	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		21,703	21,660	21,618	21,575	21,532	21,489	21,446	21,403	21,360	21,318	21,275	21,232	$257,611
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		3,967	3,959	3,952	3,944	3,936	3,928	3,920	3,912	3,905	3,897	3,889	3,881	47,090
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.33%		4,609	4,609	4,609	4,609	4,609	4,609	4,609	4,609	4,609	4,609	4,609	4,609	55,308
	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	0.009270		1,834	1,834	1,834	1,834	1,834	1,834	1,834	1,834	1,834	1,834	1,834	1,834	22,008
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			32,113	32,062	32,013	31,962	31,911	31,860	31,809	31,758	31,708	31,658	31,607	31,556	382,017
	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			32,113	32,062	32,013	31,962	31,911	31,860	31,809	31,758	31,708	31,658	31,607	31,556	382,017

CPD

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
JANUARY 2010 - DECEMBER 2010

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - University of Florida (Project 4.1h)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		(37,326)	(38,120)	(38,914)	(39,708)	(40,502)	(41,296)	(42,090)	(42,884)	(43,678)	(44,472)	(45,266)	(46,060)	(46,854)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$104,109	103,314	102,520	101,726	100,932	100,138	99,344	98,550	97,756	96,962	96,168	95,374	94,580	
6	Average Net Investment			103,711	102,917	102,123	101,329	100,535	99,741	98,947	98,153	97,359	96,565	95,771	94,977	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		965	957	950	942	935	928	920	913	905	898	891	883	$11,087
	b. Debt Component (Line 6 x 2.67% x 1/12)	2.04%		176	176	174	172	171	170	168	167	166	164	163	161	2,027
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	6.74%		794	794	794	794	794	794	794	794	794	794	794	794	9,528
	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	0.013790		163	163	163	163	163	163	163	163	163	163	163	163	1,956
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,098	2,089	2,081	2,071	2,063	2,055	2,045	2,037	2,028	2,019	2,011	2,001	24,598
	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			2,098	2,089	2,081	2,071	2,063	2,055	2,045	2,037	2,028	2,019	2,011	2,001	24,598

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Anclote (Project 4.3)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	
3	Less: Accumulated Depreciation		(22,218)	(23,026)	(23,834)	(24,642)	(25,450)	(26,258)	(27,066)	(27,874)	(28,682)	(29,490)	(30,298)	(31,106)	(31,914)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$268,080	267,272	266,464	265,656	264,848	264,040	263,232	262,424	261,616	260,808	260,000	259,192	258,384	
6	Average Net Investment			267,676	266,868	266,060	265,252	264,444	263,636	262,828	262,020	261,212	260,404	259,596	258,788	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		2,489	2,482	2,474	2,467	2,459	2,452	2,444	2,437	2,429	2,422	2,414	2,407	$29,376
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		455	454	452	451	450	448	447	445	444	443	441	440	5,370
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.34%		808	808	808	808	808	808	808	808	808	808	808	808	9,696
	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	0.007100		172	172	172	172	172	172	172	172	172	172	172	172	2,064
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			3,924	3,916	3,906	3,898	3,889	3,880	3,871	3,862	3,853	3,845	3,835	3,827	46,506
	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			3,924	3,916	3,906	3,898	3,889	3,880	3,871	3,862	3,853	3,845	3,835	3,827	46,506

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
JANUARY 2010 - DECEMBER 2010

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Crystal River 4 & 5 (Project 4.2a)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	
3	Less: Accumulated Depreciation		(59,422)	(64,223)	(69,024)	(73,825)	(78,626)	(83,427)	(88,228)	(93,029)	(97,830)	(102,631)	(107,432)	(112,233)	(117,034)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$1,976,276	1,971,475	1,966,674	1,961,873	1,957,072	1,952,271	1,947,470	1,942,669	1,937,868	1,933,067	1,928,266	1,923,465	1,918,664	
6	Average Net Investment			1,973,876	1,969,075	1,964,274	1,959,473	1,954,672	1,949,871	1,945,070	1,940,269	1,935,468	1,930,667	1,925,866	1,921,065	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		18,357	18,312	18,268	18,223	18,178	18,134	18,089	18,045	18,000	17,956	17,911	17,866	$217,339
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		3,356	3,347	3,339	3,331	3,323	3,315	3,307	3,298	3,290	3,282	3,274	3,266	39,726
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.83%		4,801	4,801	4,801	4,801	4,801	4,801	4,801	4,801	4,801	4,801	4,801	4,801	57,612
	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	0.010480		1,778	1,778	1,778	1,778	1,778	1,778	1,778	1,778	1,778	1,778	1,778	1,778	21,336
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			28,292	28,238	28,186	28,133	28,080	28,026	27,975	27,922	27,869	27,816	27,764	27,711	336,014
	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			28,292	28,238	28,186	28,133	28,080	28,026	27,975	27,922	27,869	27,816	27,764	27,711	336,014

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Higgins (Project 4.1l)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$343,893	343,893	343,893	343,893	343,893	343,893	343,893	343,893	343,893	343,893	343,893	343,893	343,893	
3	Less: Accumulated Depreciation		(10,374)	(11,970)	(13,566)	(15,162)	(16,758)	(18,354)	(19,950)	(21,546)	(23,142)	(24,738)	(26,334)	(27,930)	(29,526)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$333,519	331,923	330,327	328,731	327,135	325,539	323,943	322,347	320,751	319,155	317,559	315,963	314,367	
6	Average Net Investment			332,721	331,125	329,529	327,933	326,337	324,741	323,145	321,549	319,953	318,357	316,761	315,165	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		3,094	3,079	3,065	3,050	3,035	3,020	3,005	2,990	2,976	2,961	2,946	2,931	$36,152
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		566	563	560	557	555	552	549	547	544	541	538	536	6,608
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	5.57%		1,596	1,596	1,596	1,596	1,596	1,596	1,596	1,596	1,596	1,596	1,596	1,596	19,152
	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	0.009130		262	262	262	262	262	262	262	262	262	262	262	262	3,144
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			5,518	5,500	5,483	5,465	5,448	5,430	5,412	5,395	5,378	5,360	5,342	5,325	65,056
	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			5,518	5,500	5,483	5,465	5,448	5,430	5,412	5,395	5,378	5,360	5,342	5,325	65,056

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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.2 Recap
JANUARY 2010 - DECEMBER 2010

For Project: CAIR CTs - AVON PARK (Project 7.2a)
(in Dollars)

Line Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	
3 Less: Accumulated Depreciation		(4,553)	(4,731)	(4,909)	(5,087)	(5,265)	(5,443)	(5,621)	(5,799)	(5,977)	(6,155)	(6,333)	(6,511)	(6,689)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$157,201	157,023	156,845	156,667	156,489	156,311	156,133	155,955	155,777	155,599	155,421	155,243	155,065	
6 Average Net Investment			157,112	156,934	156,756	156,578	156,400	156,222	156,044	155,866	155,688	155,510	155,332	155,154	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		1,461	1,459	1,458	1,456	1,455	1,453	1,451	1,450	1,448	1,446	1,445	1,443	$17,425
b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		267	267	266	266	266	266	265	265	265	264	264	264	3,165
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	1.32%		178	178	178	178	178	178	178	178	178	178	178	178	2,136
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	0.008760		118	118	118	118	118	118	118	118	118	118	118	118	1,416
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			2,024	2,022	2,020	2,018	2,017	2,015	2,012	2,011	2,009	2,008	2,005	2,003	24,162
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			2,024	2,022	2,020	2,018	2,017	2,015	2,012	2,011	2,009	2,008	2,005	2,003	24,162

For Project: CAIR CTs - BARTOW (Project 7.2b)
(in Dollars)

Line Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	
3 Less: Accumulated Depreciation		(19,273)	(20,032)	(20,791)	(21,550)	(22,309)	(23,068)	(23,827)	(24,586)	(25,345)	(26,104)	(26,863)	(27,622)	(28,381)	
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)		$256,074	255,315	254,556	253,797	253,038	252,279	251,520	250,761	250,002	249,243	248,484	247,725	246,966	
6 Average Net Investment			255,695	254,936	254,177	253,418	252,659	251,900	251,141	250,382	249,623	248,864	248,105	247,346	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		2,378	2,371	2,364	2,357	2,350	2,343	2,336	2,329	2,321	2,314	2,307	2,300	$28,070
b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		435	433	432	431	430	428	427	426	424	423	422	420	5,131
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	3.31%		759	759	759	759	759	759	759	759	759	759	759	759	9,108
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	0.009130		209	209	209	209	209	209	209	209	209	209	209	209	2,508
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			3,781	3,772	3,764	3,756	3,748	3,739	3,731	3,723	3,713	3,705	3,697	3,688	44,817
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			3,781	3,772	3,764	3,756	3,748	3,739	3,731	3,723	3,713	3,705	3,697	3,688	44,817

090007 Hearing Exhibit - 00002861

PEF-POD5-00029

CPD

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.2 Recap
JANUARY 2010 - DECEMBER 2010

For Project: CAIR CTs - BAYBORO (Project 7.2c)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	
3	Less: Accumulated Depreciation		(11,079)	(11,515)	(11,951)	(12,387)	(12,823)	(13,259)	(13,695)	(14,131)	(14,567)	(15,003)	(15,439)	(15,875)	(16,311)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$187,909	187,473	187,037	186,601	186,165	185,729	185,293	184,857	184,421	183,985	183,549	183,113	182,677	
6	Average Net Investment			187,691	187,255	186,819	186,383	185,947	185,511	185,075	184,639	184,203	183,767	183,331	182,895	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		1,746	1,741	1,737	1,733	1,729	1,725	1,721	1,717	1,713	1,709	1,705	1,701	$20,677
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		319	318	318	317	316	315	315	314	313	312	312	311	3,760
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.63%		436	436	436	436	436	436	436	436	436	436	436	436	5,232
	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	0.009130		151	151	151	151	151	151	151	151	151	151	151	151	1,812
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,652	2,646	2,642	2,637	2,632	2,627	2,623	2,618	2,613	2,608	2,604	2,599	31,501
	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			2,652	2,646	2,642	2,637	2,632	2,627	2,623	2,618	2,613	2,608	2,604	2,599	31,501

For Project: CAIR CTs - DeBARY (Project 7.2d)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	
3	Less: Accumulated Depreciation		(6,375)	(6,623)	(6,871)	(7,119)	(7,367)	(7,615)	(7,863)	(8,111)	(8,359)	(8,607)	(8,855)	(9,103)	(9,351)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$81,292	81,044	80,796	80,548	80,300	80,052	79,804	79,556	79,308	79,060	78,812	78,564	78,316	
6	Average Net Investment			81,168	80,920	80,672	80,424	80,176	79,928	79,680	79,432	79,184	78,936	78,688	78,440	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		755	753	750	748	746	743	741	739	736	734	732	729	$8,906
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		138	138	137	137	136	136	135	135	135	134	134	133	1,628
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.39%		248	248	248	248	248	248	248	248	248	248	248	248	2,976
	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	0.009270		68	68	68	68	68	68	68	68	68	68	68	68	816
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,209	1,207	1,203	1,201	1,198	1,195	1,192	1,190	1,187	1,184	1,182	1,178	14,326
	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			1,209	1,207	1,203	1,201	1,198	1,195	1,192	1,190	1,187	1,184	1,182	1,178	14,326

090007 Hearing Exhibit - 00002862

PEF-POD5-00030

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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.2 Recap
JANUARY 2010 - DECEMBER 2010

For Project: CAIR CTs - HIGGINS (Project 7.2e)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	
3	Less: Accumulated Depreciation		(6,697)	(6,985)	(7,273)	(7,561)	(7,849)	(8,137)	(8,425)	(8,713)	(9,001)	(9,289)	(9,577)	(9,865)	(10,153)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$338,793	338,505	338,217	337,929	337,641	337,353	337,065	336,777	336,489	336,201	335,913	335,625	335,337	
6	Average Net Investment			338,649	338,361	338,073	337,785	337,497	337,209	336,921	336,633	336,345	336,057	335,769	335,481	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		3,149	3,147	3,144	3,141	3,139	3,136	3,133	3,131	3,128	3,125	3,123	3,120	$37,616
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		576	575	575	574	574	573	573	572	572	571	571	570	6,876
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.00%		288	288	288	288	288	288	288	288	288	288	288	288	3,456
	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	0.009130		263	263	263	263	263	263	263	263	263	263	263	263	3,156
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			4,276	4,273	4,270	4,268	4,264	4,260	4,257	4,254	4,251	4,247	4,245	4,241	51,104
	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			4,276	4,273	4,270	4,268	4,264	4,260	4,257	4,254	4,251	4,247	4,245	4,241	51,104

For Project: CAIR CTs - INTERCESSION CITY (Project 7.2f)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	
3	Less: Accumulated Depreciation		(19,459)	(20,225)	(20,991)	(21,757)	(22,523)	(23,289)	(24,055)	(24,821)	(25,587)	(26,353)	(27,119)	(27,885)	(28,651)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$330,125	329,359	328,593	327,827	327,061	326,295	325,529	324,763	323,997	323,231	322,465	321,699	320,933	
6	Average Net Investment			329,742	328,976	328,210	327,444	326,678	325,912	325,146	324,380	323,614	322,848	322,082	321,316	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		3,067	3,059	3,052	3,045	3,038	3,031	3,024	3,017	3,010	3,002	2,995	2,988	$36,328
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		561	559	558	557	555	554	553	551	550	549	548	546	6,641
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.63%		766	766	766	766	766	766	766	766	766	766	766	766	9,192
	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	0.007740		225	225	225	225	225	225	225	225	225	225	225	225	2,700
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			4,619	4,609	4,601	4,593	4,584	4,576	4,568	4,559	4,551	4,542	4,534	4,525	54,861
	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			4,619	4,609	4,601	4,593	4,584	4,576	4,568	4,559	4,551	4,542	4,534	4,525	54,861

PEF-POD5-00031

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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.2 Recap
JANUARY 2010 - DECEMBER 2010

For Project: CAIR CTs - TURNER (Project 7.2g)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	
3	Less: Accumulated Depreciation		(7,767)	(8,073)	(8,379)	(8,685)	(8,991)	(9,297)	(9,603)	(9,909)	(10,215)	(10,521)	(10,827)	(11,133)	(11,439)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$126,245	125,939	125,633	125,327	125,021	124,715	124,409	124,103	123,797	123,491	123,185	122,879	122,573	
6	Average Net Investment			126,092	125,786	125,480	125,174	124,868	124,562	124,256	123,950	123,644	123,338	123,032	122,726	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		1,173	1,170	1,167	1,164	1,161	1,158	1,156	1,153	1,150	1,147	1,144	1,141	$13,864
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		214	214	213	213	212	212	211	211	210	210	209	209	2,536
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.74%		306	306	306	306	306	306	306	306	306	306	306	306	3,672
	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	0.009270		104	104	104	104	104	104	104	104	104	104	104	104	1,248
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,787	1,794	1,790	1,787	1,783	1,780	1,777	1,774	1,770	1,767	1,763	1,760	21,342
	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			1,797	1,794	1,790	1,787	1,783	1,780	1,777	1,774	1,770	1,767	1,763	1,760	21,342

For Project: CAIR CTs - SUWANNEE (Project 7.2h)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	
3	Less: Accumulated Depreciation		(15,822)	(16,496)	(17,170)	(17,844)	(18,518)	(19,192)	(19,866)	(20,540)	(21,214)	(21,888)	(22,562)	(23,236)	(23,910)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$365,738	365,064	364,390	363,716	363,042	362,368	361,694	361,020	360,346	359,672	358,998	358,324	357,650	
6	Average Net Investment			365,401	364,727	364,053	363,379	362,705	362,031	361,357	360,683	360,009	359,335	358,661	357,987	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		3,398	3,392	3,386	3,379	3,373	3,367	3,361	3,354	3,348	3,342	3,336	3,329	$40,365
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		621	620	619	618	617	616	614	613	612	611	610	609	7,379
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.12%		674	674	674	674	674	674	674	674	674	674	674	674	8,088
	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	0.007860		250	250	250	250	250	250	250	250	250	250	250	250	3,000
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			4,943	4,936	4,929	4,921	4,914	4,908	4,899	4,891	4,884	4,877	4,870	4,862	58,832
	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			4,943	4,936	4,929	4,921	4,914	4,908	4,899	4,891	4,884	4,877	4,870	4,862	58,832

090007 Hearing Exhibit - 00002864

PEF-POD5-00032

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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2010 - DECEMBER 2010

For Project: CAIR/CAMR Crystal River AFUDC - Access Road and Vehicle Barrier System (Project 7.4a)
(in Dollars)

Line Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	
3 Less: Accumulated Depreciation		(863,406)	(907,165)	(950,925)	(994,685)	(1,038,445)	(1,082,205)	(1,125,965)	(1,169,725)	(1,213,485)	(1,257,245)	(1,301,005)	(1,344,765)	(1,388,525)	
4 CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$14,626,977	14,583,217	14,539,457	14,495,697	14,451,937	14,408,177	14,364,417	14,320,657	14,276,897	14,233,137	14,189,377	14,145,617	14,101,857	
6 Average Net Investment			14,605,097	14,561,337	14,517,577	14,473,817	14,430,057	14,386,297	14,342,537	14,298,777	14,255,017	14,211,257	14,167,497	14,123,737	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		135,827	135,420	135,013	134,606	134,200	133,793	133,386	132,979	132,572	132,165	131,758	131,351	$1,603,070
b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		24,829	24,754	24,680	24,605	24,531	24,457	24,382	24,308	24,234	24,159	24,085	24,010	293,034
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	3.39%		43,760	43,760	43,760	43,760	43,760	43,760	43,760	43,760	43,760	43,760	43,760	43,760	525,120
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	0.010480		13,528	13,528	13,528	13,528	13,528	13,528	13,528	13,528	13,528	13,528	13,528	13,528	162,336
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			217,944	217,462	216,981	216,499	216,019	215,538	215,056	214,575	214,094	213,612	213,131	212,649	2,583,560
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			217,944	217,462	216,981	216,499	216,019	215,538	215,056	214,575	214,094	213,612	213,131	212,649	2,583,560

For Project: CAIR/CAMR Crystal River AFUDC - Low Nox Burner CR4 (Project 7.4b)
(in Dollars)

Line Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	
3 Less: Accumulated Depreciation		(271,659)	(296,238)	(320,817)	(345,396)	(369,975)	(394,554)	(419,133)	(443,712)	(468,291)	(492,870)	(517,449)	(542,028)	(566,607)	
4 CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$10,150,322	10,125,743	10,101,164	10,076,585	10,052,006	10,027,427	10,002,848	9,978,269	9,953,690	9,929,111	9,904,532	9,879,953	9,855,374	
6 Average Net Investment			10,138,032	10,113,453	10,088,874	10,064,295	10,039,717	10,015,138	9,990,559	9,965,980	9,941,401	9,916,822	9,892,243	9,867,664	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		94,284	94,055	93,827	93,598	93,369	93,141	92,912	92,684	92,455	92,226	91,998	91,769	$1,118,318
b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		17,235	17,193	17,151	17,109	17,068	17,026	16,984	16,942	16,900	16,859	16,817	16,775	204,059
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	2.83%		24,579	24,579	24,579	24,579	24,579	24,579	24,579	24,579	24,579	24,579	24,579	24,579	294,948
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	0.010480		9,102	9,102	9,102	9,102	9,102	9,102	9,102	9,102	9,102	9,102	9,102	9,102	109,224
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			145,200	144,929	144,659	144,388	144,118	143,848	143,577	143,307	143,036	142,766	142,496	142,225	1,724,549
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			145,200	144,929	144,659	144,388	144,118	143,848	143,577	143,307	143,036	142,766	142,496	142,225	1,724,549

090007 Hearing Exhibit - 00002865

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2010 - DECEMBER 2010

For Project: CAIR/CAMR Crystal River AFUDC - Selective Catalytic Reduction CR5 (Project 7.4c)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			20,000	20,000	20,000	20,000	20,000	20,000	20,000	$0	$0	$0	$0	$0	$140,000
	b. Clearings to Plant			20,000	20,000	20,000	20,000	20,000	20,000	20,000	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		$92,494,737	92,514,737	92,534,737	92,554,737	92,574,737	92,594,737	92,614,737	92,634,737	92,634,737	92,634,737	92,634,737	92,634,737	92,634,737	
3	Less: Accumulated Depreciation		(1,414,531)	(1,632,712)	(1,850,940)	(2,069,215)	(2,287,537)	(2,505,906)	(2,724,322)	(2,942,786)	(3,161,250)	(3,379,714)	(3,598,178)	(3,816,642)	(4,035,106)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$91,080,206	90,882,025	90,683,797	90,485,522	90,287,200	90,088,831	89,890,415	89,691,951	89,473,487	89,255,023	89,036,559	88,818,095	88,599,631	
6	Average Net Investment			90,981,115	90,782,911	90,584,659	90,386,361	90,188,015	89,989,623	89,791,183	89,582,719	89,364,255	89,145,791	88,927,327	88,708,863	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		846,124	844,281	842,437	840,593	838,749	836,903	835,056	833,119	831,086	829,056	827,024	824,992	$10,029,424
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		154,688	154,331	153,994	153,657	153,320	152,982	152,645	152,291	151,919	151,548	151,176	150,805	1,833,336
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.83%		218,181	218,228	218,275	218,322	218,369	218,416	218,464	218,464	218,464	218,464	218,464	218,464	2,620,573
	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	0.010480		80,796	80,814	80,831	80,849	80,866	80,884	80,901	80,901	80,901	80,901	80,901	80,901	970,445
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,299,789	1,297,654	1,295,537	1,293,421	1,291,304	1,289,185	1,287,066	1,284,775	1,282,372	1,279,969	1,277,565	1,275,162	15,453,781
	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			1,299,789	1,297,654	1,295,537	1,293,421	1,291,304	1,289,185	1,287,066	1,284,775	1,282,372	1,279,969	1,277,565	1,275,162	15,453,781

For Project: CAIR/CAMR Crystal River AFUDC - FGD Common (Project 7.4d)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			1,540,000	2,041,796	2,589,985	1,100,000	1,545,160	1,500,000	500,000	254,844	$0	$0	$0	$0	$11,071,785
	b. Clearings to Plant			1,540,000	2,041,796	2,589,985	1,100,000	1,545,160	1,500,000	500,000	254,844	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		$634,421,721	635,961,721	638,003,517	640,593,502	641,693,502	643,238,662	644,738,662	645,238,662	645,493,506	645,493,506	645,493,506	645,493,506	645,493,506	
3	Less: Accumulated Depreciation		(744,089)	(2,247,899)	(3,752,524)	(5,263,257)	(6,776,584)	(8,293,555)	(9,814,064)	(11,335,752)	(12,858,041)	(14,380,330)	(15,902,619)	(17,424,908)	(18,947,197)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$633,677,632	633,713,822	634,250,993	635,330,245	634,916,918	634,945,107	634,924,598	633,902,910	632,635,465	631,113,176	629,590,887	628,068,598	626,546,309	
6	Average Net Investment			633,693,727	633,982,408	634,790,619	635,123,582	634,931,013	634,934,853	634,413,754	633,269,188	631,874,321	630,352,032	628,829,743	627,307,454	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		5,893,352	5,896,036	5,903,553	5,906,849	5,904,858	5,904,894	5,900,048	5,889,403	5,876,431	5,862,274	5,848,117	5,833,959	$70,619,574
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		1,077,279	1,077,770	1,079,144	1,079,710	1,079,383	1,079,389	1,078,503	1,076,558	1,074,186	1,071,598	1,069,011	1,066,423	12,903,954
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.83%		1,499,810	1,504,625	1,510,733	1,513,327	1,516,971	1,520,509	1,521,688	1,522,289	1,522,289	1,522,289	1,522,289	1,522,289	18,199,105
	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	0.010480		555,407	557,190	559,452	560,412	561,762	563,072	563,508	563,731	563,731	563,731	563,731	563,731	6,739,458
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			9,025,848	9,035,621	9,052,882	9,060,098	9,062,974	9,067,864	9,063,747	9,051,981	9,036,637	9,019,892	9,003,148	8,986,402	108,467,094
	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			9,025,848	9,035,621	9,052,882	9,060,098	9,062,974	9,067,864	9,063,747	9,051,981	9,036,637	9,019,892	9,003,148	8,986,402	108,467,094

090007 Hearing Exhibit - 00002866

PEF-POD5-00033

CPD

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2010 - DECEMBER 2010

For Project: CAIR/CAMR Crystal River AFUDC - SCR Common Items (Project 7.4e)
(in Dollars)

Line Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$69,831,473	69,831,473	69,831,473	69,831,473	69,831,473	69,831,473	69,831,473	69,831,473	69,831,473	69,831,473	69,831,473	69,831,473.14	69,831,473	
3 Less: Accumulated Depreciation		(905,773)	(1,070,459)	(1,235,145)	(1,399,831)	(1,564,517)	(1,729,203)	(1,893,889)	(2,058,575)	(2,223,261)	(2,387,947)	(2,552,633)	(2,717,319)	(2,882,005)	
4 CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$68,925,700	68,761,014	68,596,328	68,431,642	68,266,956	68,102,270	67,937,584	67,772,898	67,608,212	67,443,526	67,278,840	67,114,154	66,949,468	
6 Average Net Investment			68,843,357	68,678,671	68,513,985	68,349,299	68,184,613	68,019,927	67,855,241	67,690,555	67,525,869	67,361,183	67,196,497	67,031,811	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		640,243	638,712	637,180	635,648	634,117	632,585	631,054	629,522	627,991	626,459	624,927	623,396	$7,581,134
b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		117,034	116,754	116,474	116,194	115,914	115,634	115,354	115,074	114,794	114,514	114,234	113,954	1,385,928
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	2.83%		164,686	164,686	164,686	164,686	164,686	164,686	164,686	164,686	164,686	164,686	164,686	164,686	1,976,232
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	0.010480		60,986	60,986	60,986	60,986	60,986	60,986	60,986	60,986	60,986	60,986	60,986	60,986	731,832
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			982,949	981,138	979,326	977,514	975,703	973,891	972,080	970,268	968,457	966,645	964,833	963,022	11,675,826
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			982,949	981,138	979,326	977,514	975,703	973,891	972,080	970,268	968,457	966,645	964,833	963,022	11,675,826

For Project: CAIR/CAMR Crystal River AFUDC - Flue Gas Desulfurization CR5 (Project 7.4f)
(in Dollars)

Line Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	End of Period Total
1 Investments															
a. Expenditures/Additions			$0	1,226,404	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,226,404
b. Clearings to Plant			0	1,226,404	0	0	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		$135,013,655	135,013,655	136,240,059	136,240,059	136,240,059	136,240,059	136,240,059	136,240,059	136,240,059	136,240,059	136,240,059	136,240,059	136,240,059	
3 Less: Accumulated Depreciation		(159,204)	(477,611)	(798,910)	(1,120,209)	(1,441,508)	(1,762,807)	(2,084,106)	(2,405,405)	(2,726,704)	(3,048,003)	(3,369,302)	(3,690,601)	(4,011,900)	
4 CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$134,854,452	134,536,045	135,441,150	135,119,851	134,798,552	134,477,253	134,155,954	133,834,655	133,513,356	133,192,057	132,870,758	132,549,459	132,228,160	
6 Average Net Investment			134,695,248	134,988,597	135,280,500	134,959,201	134,637,902	134,316,603	133,995,304	133,674,005	133,352,706	133,031,407	132,710,108	132,388,809	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		1,252,656	1,255,394	1,258,109	1,255,121	1,252,132	1,249,144	1,246,156	1,243,168	1,240,180	1,237,192	1,234,204	1,231,216	$14,954,682
b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		228,982	229,481	229,977	229,431	228,884	228,338	227,792	227,246	226,700	226,153	225,607	225,061	2,733,652
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	2.83%		318,407	321,299	321,299	321,299	321,299	321,299	321,299	321,299	321,299	321,299	321,299	321,299	3,852,696
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	0.010480		117,912	118,983	118,983	118,983	118,983	118,983	118,983	118,983	118,983	118,983	118,983	118,983	1,426,725
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			1,917,987	1,925,157	1,928,368	1,924,834	1,921,298	1,917,764	1,914,230	1,910,696	1,907,162	1,903,627	1,900,093	1,896,559	22,987,755
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			1,917,987	1,925,157	1,928,368	1,924,834	1,921,298	1,917,764	1,914,230	1,910,696	1,907,162	1,903,627	1,900,093	1,896,559	22,987,755

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2010 - DECEMBER 2010
For Project: CAIR/CAMR Crystal River AFUDC - CR5 Sootblower & Intelligent Soot Blowing controls (Project 7.4g)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$929,220	929,220	929,220	929,220	929,220	929,220	929,220	929,220	929,220	929,220	929,220	929,220	929,220	
3	Less: Accumulated Depreciation		(1,096)	(3,287)	(5,478)	(7,669)	(9,860)	(12,051)	(14,242)	(16,433)	(18,624)	(20,815)	(23,006)	(25,197)	(27,388)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$928,124	925,934	923,743	921,552	919,361	917,170	914,979	912,788	910,597	908,406	906,215	904,024	901,833	
6	Average Net Investment			927,029	924,838	922,647	920,456	918,265	916,074	913,883	911,692	909,501	907,310	905,119	902,928	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		8,621	8,601	8,581	8,560	8,540	8,519	8,499	8,479	8,458	8,438	8,418	8,397	$102,111
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		1,576	1,572	1,568	1,565	1,561	1,557	1,554	1,550	1,546	1,542	1,539	1,535	18,665
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.83%		2,191	2,191	2,191	2,191	2,191	2,191	2,191	2,191	2,191	2,191	2,191	2,191	26,292
	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	0.010480		812	812	812	812	812	812	812	812	812	812	812	812	9,744
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			13,200	13,176	13,152	13,128	13,104	13,079	13,056	13,032	13,007	12,983	12,960	12,935	156,812
	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			13,200	13,176	13,152	13,128	13,104	13,079	13,056	13,032	13,007	12,983	12,960	12,935	156,812

For Project: CAIR/CAMR Crystal River AFUDC - CR4 Sootblower & Intelligent Soot Blowing controls (Project 7.4h)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$ 949,211	$0	$0	$0	$0	$0	$0	$0	$949,211
	b. Clearings to Plant			0	0	0	0	949,211	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	949,211	949,211	949,211	949,211	949,211	949,211	949,211	949,211	
3	Less: Accumulated Depreciation		-	0	0	0	0	(1,120)	(3,359)	(5,598)	(7,837)	(10,076)	(12,315)	(14,554)	(16,793)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$0	0	0	0	0	948,091	945,852	943,613	941,374	939,135	936,896	934,657	932,418	
6	Average Net Investment			0	0	0	0	474,046	946,972	944,733	942,494	940,255	938,016	935,777	933,538	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		0	0	0	0	4,409	8,807	8,786	8,765	8,744	8,724	8,703	8,682	$65,620
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		0	0	0	0	806	1,610	1,606	1,602	1,598	1,595	1,591	1,587	11,995
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.83%		0	0	0	0	1,120	2,239	2,239	2,239	2,239	2,239	2,239	2,239	16,793
	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	0.010480		0	0	0	0	829	829	829	829	829	829	829	829	6,632
	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	7,164	13,485	13,460	13,435	13,410	13,387	13,362	13,337	101,040
	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	7,164	13,485	13,460	13,435	13,410	13,387	13,362	13,337	101,040

CPD

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2010 - DECEMBER 2010

For Project: CAIR/CAMR Crystal River AFUDC - CR4 SCR (Project 7.4i)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$108,219,363	1,435,613	1,632,028	195,809	183,116	174,307	174,129	174,076	$112,188,441
	b. Clearings to Plant			0	0	0	0	108,219,363	1,435,613	1,632,028	195,809	183,116	174,307	174,129	174,076	
	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	108,219,363	109,654,976	111,287,004	111,482,813	111,665,929	111,840,235	112,014,364	112,188,441	
3	Less: Accumulated Depreciation		-	0	0	0	0	(127,609)	(386,212)	(648,664)	(911,578)	(1,174,923)	(1,438,680)	(1,702,847)	(1,967,425)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$0	0	0	0	0	108,091,755	109,268,764	110,638,341	110,571,236	110,491,006	110,401,556	110,311,518	110,221,016	
6	Average Net Investment			0	0	0	0	54,045,877	108,680,260	109,953,553	110,604,788	110,531,121	110,446,281	110,356,537	110,266,267	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.18%		0	0	0	0	502,627	1,010,726	1,022,566	1,028,625	1,027,939	1,027,150	1,026,316	1,025,476	$7,671,427
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		0	0	0	0	91,878	184,756	186,921	188,028	187,903	187,759	187,606	187,453	1,402,304
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.83%		0	0	0	0	127,609	258,603	262,452	262,914	263,345	263,757	264,167	264,578	1,967,425
	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	0.010480		0	0	0	0	94,512	95,765	97,191	97,362	97,522	97,674	97,828	97,978	775,830
	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	816,626	1,549,850	1,569,132	1,576,929	1,576,709	1,576,340	1,575,915	1,575,485	11,816,986
	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	816,626	1,549,850	1,569,132	1,576,929	1,576,709	1,576,340	1,575,915	1,575,485	11,816,986

For Project: CAIR/CAMR Crystal River AFUDC - CR4 FGD (Project 7.4j)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$138,386,946	478,327	1,779,294	239,128	223,627	212,870	212,652	212,588	$141,745,432
	b. Clearings to Plant			0	0	0	0	138,386,946	478,327	1,779,294	239,128	223,627	212,870	212,652	212,588	
	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	138,386,946	138,865,273	140,644,566	140,883,695	141,107,322	141,320,191	141,532,844	141,745,432	
3	Less: Accumulated Depreciation		-	0	0	0	0	(163,182)	(490,673)	(822,360)	(1,154,611)	(1,487,389)	(1,820,669)	(2,154,451)	(2,488,734)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$0	0	0	0	0	138,223,765	138,374,600	139,822,207	139,729,084	139,619,933	139,499,523	139,378,393	139,256,698	
6	Average Net Investment			0	0	0	0	69,111,882	138,299,182	139,098,404	139,775,645	139,674,509	139,559,728	139,438,958	139,317,546	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.18%		0	0	0	0	642,741	1,286,182	1,293,615	1,299,913	1,298,973	1,297,905	1,296,782	1,295,653	$9,711,764
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		0	0	0	0	117,490	235,109	238,467	237,619	237,447	237,252	237,046	236,840	1,775,270
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.83%		0	0	0	0	163,182	327,491	331,687	332,251	332,778	333,280	333,782	334,283	2,488,734
	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	0.010480		0	0	0	0	120,856	121,278	122,830	123,038	123,234	123,420	123,605	123,791	982,052
	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	1,044,271	1,970,058	1,984,599	1,992,821	1,992,432	1,991,857	1,991,215	1,990,587	14,957,820
	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	1,044,271	1,970,058	1,984,599	1,992,821	1,992,432	1,991,857	1,991,215	1,990,587	14,957,820

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2010 - DECEMBER 2010

For Project: CAIR/CAMR Crystal River AFUDC - Gypsum Handling (Project 7.4k)
(in Dollars)

Line Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$20,873,018	20,873,018	20,873,018	20,873,018	20,873,018	20,873,018	20,873,018	20,873,018	20,873,018	20,873,018	20,873,018	20,873,018	20,873,018	
3 Less: Accumulated Depreciation		(44,964)	(94,190)	(143,416)	(192,642)	(241,868)	(291,094)	(340,320)	(389,546)	(438,772)	(487,998)	(537,224)	(586,450)	(635,676)	
4 CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$20,828,054	20,778,828	20,729,602	20,680,376	20,631,150	20,581,924	20,532,698	20,483,472	20,434,246	20,385,020	20,335,794	20,286,568	20,237,342	
6 Average Net Investment			20,803,441	20,754,215	20,704,989	20,655,763	20,606,537	20,557,311	20,508,085	20,458,859	20,409,633	20,360,407	20,311,181	20,261,955	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		193,472	193,014	192,556	192,099	191,641	191,183	190,725	190,267	189,810	189,352	188,894	188,436	$2,291,449
b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		35,366	35,282	35,198	35,115	35,031	34,947	34,864	34,780	34,696	34,613	34,529	34,445	416,866
c. Other			114,545	0	0	0	0	0	0	0	0	0	0	0	114,545
8 Investment Expenses															
a. Depreciation	2.83%		49,226	49,226	49,226	49,226	49,226	49,226	49,226	49,226	49,226	49,226	49,226	49,226	590,712
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	0.010480		18,229	18,229	18,229	18,229	18,229	18,229	18,229	18,229	18,229	18,229	18,229	18,229	218,748
e. Other			63,193	0	0	0	0	0	0	0	0	0	0	0	63,193
9 Total System Recoverable Expenses (Lines 7 + 8)			474,031	295,751	295,209	294,669	294,127	293,585	293,044	292,502	291,961	291,420	290,878	290,336	3,697,513
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			474,031	295,751	295,209	294,669	294,127	293,585	293,044	292,502	291,961	291,420	290,878	290,336	3,697,513

FLORIDA PUBLIC SERVICE COMMISSION

Company: PROGRESS ENERGY FLORIDA INC.

Docket No: 090079-EI

Explanation: *Provide the Company's 13-month average cost of capital for the test year, the prior year and historical base year.*

(Thousands)

Type of data shown:
X Projected Test Year Ended 12/31/2010
_ Prior Year Ended 12/31/2009
_ Historical Year Ended 12/31/2008
Witness: Toomey

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
Line No.	Class of Capital	Co Total	Specific Adjustments	Pro Rata Adjustments	System Adjusted	Jurisdictional Factor	Jurisdictional Capital Structure	Ratio	Cost Rate	Weighted Cost Rate
1										
2	Common Equity	4,603,867	706,505	(1,160,778)	4,149,594	75.95%	3,151,819	50.52%	12.54%	6.3350%
3	Preferred Stock	33,497	0	(7,322)	26,175	75.95%	19,881	0.32%	4.51%	0.0140%
4	Long Term Debt - Fixed	4,443,979	0	(971,396)	3,472,583	75.95%	2,637,596	42.28%	6.42%	2.7160%
5	Short Term Debt	72,883	(7,833)	(14,219)	50,831	75.95%	38,609	0.62%	5.25%	0.0320%
6	Customer Deposits Active	188,256	0	(41,150)	147,106	75.95%	111,734	1.79%	5.95%	0.1070%
7	Customer Deposits Inactive	1,902	0	(416)	1,486	75.95%	1,129	0.02%		
8	Investment Tax Credit Post '70 (Wtd Cost)	6,083	0	(1,330)	4,753	75.95%	3,610	0.06%	9.74%	0.0060%
9	Deferred Income Taxes	495,822	160,089	(143,373)	512,537	75.95%	389,297	6.24%		
10	FAS 109 DIT - Net	(193,855)	0	42,374	(151,480)	75.95%	(115,057)	-1.84%		
11										
12	Total	$9,652,434	$858,761	($2,297,610)	$8,213,585	75.95%	6,238,617	100.00%		9.210%
13										
14										
15										
16										
17										
18										
19										

PEF-POD5-00039

Supporting Schedules: Recap Schedules:

090007 Hearing Exhibit - 00002871

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PSC's Audit Report for PEF

FLORIDA PUBLIC SERVICE COMMISSION

DIVISION OF REGULATORY COMPLIANCE
BUREAU OF AUDITING

TAMPA DISTRICT OFFICE

PROGRESS ENERGY FLORIDA, INC.

ENVIRONMENTAL COST RECOVERY CLAUSE SUPPLEMENTAL AUDIT

HISTORICAL YEAR ENDED DECEMBER 31, 2008

DOCKET NO. 090007-EI

AUDIT CONTROL NO. 09-173-2-1

Simon Ojada, Audit Manager

Joseph W. Rohrbacher, Tampa District Supervisor

DOCUMENT NUMBER-DATE
07743 JUL 29 8
FPSC-COMMISSION CLERK

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DIVISION OF REGULATORY COMPLIANCE
AUDITOR'S REPORT

July 17, 2009

TO: FLORIDA PUBLIC SERVICE COMMISSION

We have performed the procedures enumerated later in this report to meet the agreed upon objectives set forth by the Division of Economic Regulation in its audit service request dated May 14, 2009. We have applied these procedures to the schedules prepared by Progress Energy Florida, Inc. (PEF) in support of its filing for Environmental Cost Recovery Clause in Docket No. 090007-EI.

This audit is performed following general standards and field work standards found in the AICPA Statements on Standards for Attestation Engagements. This report is based on agreed upon procedures and the report is only for internal Commission use.

OBJECTIVES AND PROCEDURES:

To audit costs of approved environmental projects recovered through the Environmental Cost Recovery Clause (ECRC).

Objectives: - Review the history of the position of three employees whose time was charged to the ECRC. Verify when the positions were created, and whether they were created as of the last rate case. Also, verify if the associated labor costs were simply payroll charges associated with modifications and expansions to employee workload due to the CAIR/CAMR CR project.

Procedures: -We verified that these positions represent a Supervisor, Lead Regulatory Specialist, and Senior Regulatory Specialist. These positions were not created as of the last rate case. All three positions were created in 2007, however, their time was not charged to ECRC until 2008 when their previous positions were filled.

Objective: - Verify the formulas used in the calculations of the Recoverable Costs Allocated to Demand-Prod-Intm and to Demand-Peaking on line 4 for the months of January, February, October, and November 2008 on Form 42-5A, O&M Activities.

Procedures: - We verified that the company used an incorrect formula, however, PEF corrected this oversight prospectively in the first quarter of 2009.

Objective: - Refer to Capital Project 4.1 Above Ground Tank Secondary Containment – Peaking on page 2 of 13 of Form 42-8A, the Capital Program Details Project 4.1a on page 4, Project 4.1c on page 5 of 14 of Form Appendix. Reconcile the calculations for the month of March (1) Project 4.1a line 6 - Average Net Investment and line 7c – Other. (2) Project 4.1c line 3 – Less Accumulated Depreciation and explain where the extra numbers come from.

Procedures: - We verified that the ($367,843) is due to costs associated with additional work necessary to bring Turner Tank 8 into compliance with the secondary containment requirements as per Rule 62-761.510 F.A.C. The additional $6,840 in depreciation was an error. It was corrected in July 2008.

Objective: - Refer to Capital Project 4.3 Above Ground Tank Secondary Containment – Intermediate on page 4 of 13 of Form 42-8A, the Capital Program Details on page 8 of 14 of Form Appendix. Please reconcile the calculations for the month of July line 3 less: Accumulated Depreciation and line 8e: Other. Find out where those extra numbers in the formula come from and what they represent.

Procedures: - We verified that the formula for the depreciation expense was utilizing the rate from project 4.1h instead of the rate for project 4.3 resulting in an overstatement of depreciation and property tax expense. This issue was recognized in July 2008, therefore, the depreciation expense was reduced and corrected in the July 2008 column for September 2007 through June 2008 (7,721) along with the correction to the property tax expense ($1,661).

Objective: - Refer to Capital Project 7.2 CAIR/CAMR-Pkg on page 7 of 13 of Form 42-8A, the Capital Program Details Project 7.2a on page 10 through Project 7.2h on page 13 of 14 of Form Appendix for the month of May 2008, line 7a – Equity and 7b – Debt. Find out where those extra numbers in the formula in the Capital Program details come from and what they represent.

Procedures: - We verified that PEF performed a reconciliation in May 2008 to ensure that the depreciation rates that were being utilized on the ECRC schedules agreed to the plant accounting system. All of the ECRC asset depreciation rates agreed to the plant system except for the two exceptions noted below for page 1 and page 7...each of the sites that are part of the CAIR/CAMR – Peaking program (CAIR CT's, 42-8E page 7), were classified in the plant system as Prime Movers which have various depreciation rates based on the plant sites per the 2005 Rate Case Settlement Agreement. However, the ECRC schedules were being depreciated using the rates for the Misc. Power Plant Equipment group. The depreciation was adjusted for these assets from their in-service dates in November 2007/January 2008 through April 2008. These adjustment calculations are included in Line 8a of Projects 7.2a through 7.2h of the Capital Program Detail with the current month actual depreciation expense. Because the Net investment would have been affected by the depreciation adjustments in the prior periods, the return on debt and equity was also adjusted.

Objective: - Refer to Capital Project 7.4 CAIR/CAMR CR AFUDC on page 9 of 13 of Form 42-8A, the Capital Program details Project 7.4a on page 14 of 14 of Form Appendix. Find out where those extra numbers in the formula, in the Capital Program Details, come from and what did they represent for the month of May on line 2 PIS, line 3 Less: Accumulated Depreciation, and line 3 CWIP-NIB, also, for the months of June, October, and November 2008, line 4 CWIP-NIB.

Procedures: - We verified that line 2 in the month of May is the amount of the project that was placed in service, line 3 is the accumulated depreciation associated with the in-service amount using the half month convention approach for the first month and line 4 is the remaining Construction Work In Progress (CWIP) balance for the project. The extra amounts for the months of June, October, and November in line 4 CWIP –NIB were included due to timing issues related to the close process. These true-ups were included in line 4 in those months in order for CWIP balance to properly remain at zero.

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PEF's 4/1/09 Review of Integrated Clean Air Compliance Plan

Docket No. 090007-EI
Progress Energy Florida
Witness: Patricia Q. West
Exhibit No. __ (PQW-1)

REDACTED

REDACTED

Progress Energy Florida

Review of Integrated Clean Air Compliance Plan

Submitted to the Florida Public Service Commission

April 1, 2009

Progress Energy

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V. Conclusion 14

Executive Summary

In the 2007 Environmental Cost Recovery Clause (ECRC) Docket (No. 070007-EI) and as reaffirmed in the 2008 ECRC Docket (No. 080007-EI), the Public Service Commission approved Progress Energy Florida's (PEF's) updated Integrated Clean Air Compliance Plan (Plan D) as a reasonable and prudent means to comply with the requirements of the Clean Air Interstate Rule (CAIR), the Clean Air Mercury Rule (CAMR), the Clean Air Visibility Rule (CAVR) and related regulatory requirements. In its final order, the Commission also directed PEF to file as part of its ECRC true-up testimony "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." This report provides the required review for 2009.

The primary components of PEF's Compliance Plan "D" are summarized as follows:

Sulfur Dioxide (SO_2):

- Installation of wet scrubbers, flue gas desulphurization system, (FGD) 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 SO_2 allowances

Nitrogen Oxides (NOx):

- Installation of low NOx burners (LNBs) and selective catalytic reduction (SCR) on Crystal River Units 4 and 5
- Installation of LNBs and separated over-fire air (LNB/SOFA) or alternative NOx controls at Anclote Units 1 and 2
- Purchase of annual and ozone season NOx allowances

Mercury:

- Co-benefit of wet scrubbers and SCRs at Crystal River Units 4 and 5
- Installation of powdered activated carbon (PAC) injection on Crystal River Unit 2
- Purchase of mercury (Hg) allowances

As detailed in PEF's 2007 ECRC filing, PEF decided upon Plan D based on a quantitative and qualitative evaluation of the ability of alternative plans to meet environmental requirements, while managing risks and controlling costs. That evaluation demonstrated that Plan D is PEF's most cost-effective alternative to meet the applicable regulatory requirements. The Plan is expected to meet environmental requirements by striking a balance between reducing emissions, primarily through the installation of controls on PEF's largest and newest coal units (Crystal River Units 4 and 5), and making strategic use of emission allowance markets.

In accordance with the Commission's final order in the 2007 ECRC docket, PEF has reviewed the efficacy of Plan D and the cost-effectiveness of retrofit options in relation to expected changes in environmental regulations. With regard to Plan D's efficacy, PEF remains confident that Plan D will have the desired effect of achieving timely compliance with the applicable regulations in a cost-effective manner. PEF has achieved several project milestones, including:

- Completion of the access road in May, 2008;
- Completion of the vehicle barrier system in May, 2008;
- Completion of the flue gas chimney shell in June, 2008;
- Completion of the Crystal River Unit 5 FGD absorber tower in September, 2008; and
- Completion of the Crystal River Unit 4 LNB/AH in December, 2008

Although there are uncertainties associated with all major construction projects of this type, the Crystal River projects currently are on-schedule to achieve compliance with the applicable regulations.

As a result of a 2008 federal appeals court decision vacating the federal CAMR regulations, the U.S. Environmental Protection Agency (EPA) is proceeding with adoption of new standards for utility mercury emissions. This development does not immediately impact PEF's implementation of Plan D because the plan does not contemplate installation of mercury-specific controls until 2017 if necessary. Thus, Plan D provides PEF flexibility to respond when EPA adopts any new mercury standards.

Since last year's filing, a federal appellate court also issued a decision remanding CAIR to the EPA to correct several flaws identified by the court. Although the court originally vacated the rule, in response to EPA's petition for rehearing, the court subsequently decided to remand CAIR without vacating it, thereby leaving the rule and its compliance obligations in place.

No new or revised environmental regulations have been adopted that have a direct bearing on PEF's compliance plan. In 2008, the Florida Legislature adopted legislation authorizing the Florida Department of Environmental Protection (FDEP) to adopt rules establishing a cap-and-trade program to regulate emissions of greenhouse gases, such as carbon dioxide (CO_2). To date, FDEP has not adopted any cap-and-trade rules and, under the legislation, any such rules must be ratified by the Legislature, however, the FDEP has begun the rulemaking process and held a public workshop on March 11, 2009. Nevertheless, PEF is taking steps to reduce CO_2 emissions consistent with the state's goals. Among other things, the Company has agreed to retire Crystal River Units 1 and 2 as coal-fired units after the second of two new, advanced design nuclear units in Levy County completes its first fuel cycle. This will reduce PEF's CO_2 emissions by approximately 5 million tons per year.

There currently are no demonstrated retrofit options to reduce CO_2 emissions from fossil fuel-fired electric generating units such as Crystal River Units 4 and 5, which are the primary focus of PEF's compliance plan. Likewise, replacement of coal-fired generation from Crystal River Units 4 and 5 with natural-gas fired generation is not a feasible or cost-effective option because it cannot be implemented in time to meet the 2009 and 2010 CAIR deadlines and it would put PEF in the vulnerable position of relying solely on SO_2 and NOx allowance purchases to achieve compliance during the five to six year interim period it would take to construct a new generating facility. Furthermore, replacing coal-fired generation with gas-fired generation would decrease PEF's fuel diversity and potentially increase fuel price volatility.

I. Introduction

In its final order in the 2007 ECRC Docket (No. 070007-EI) and as reaffirmed in the 2008 ECRC Docket (No. 080007-EI), the Public Service Commission approved PEF's updated Integrated Clean Air Compliance Plan (Plan D) as a reasonable and prudent means to comply with the requirements of CAIR, CAMR, CAVR and related regulatory requirements. *In re*

Environmental Cost Recovery Clause, Order No. PSC-07-0922-FOF-EI, p. 8 (Nov. 16, 2007) the Commission specifically found that "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." *Id.* In its final order, the Commission also directed PEF to file as part of its ECRC true-up testimony "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." *Id.* The purpose of this report is to provide the required review for 2009.

II. PEF's Integrated Clean Air Compliance Plan

A. Background

The CAIR and CAVR programs require PEF and other utilities to significantly reduce emissions of sulfur dioxide (SO_2) and nitrogen oxides (NOx). Under CAIR, these reductions must be met in incremental phases. Phase I begins in 2009 for NOx and in 2010 for SO_2. Phase II begins in 2015 for both NOx and SO_2.

In March 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. The analysis included an examination of the projected emissions associated with several alternative plans and a comparison of economic impacts, in terms of cumulative present value of revenue requirements. 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.

In June 2007, PEF submitted an updated report and supporting testimony summarizing the status of the Plan and an updated economic analysis incorporating certain plan revisions necessitated by changed circumstances. Consistent with the approach utilized in 2006, PEF performed a quantitative evaluation to compare the ability of the modified alternative plans to meet environmental requirements, while managing risks and controlling costs. That evaluation demonstrated that Plan D, as revised, is PEF's most cost-effective alternative to meet the applicable regulatory requirements. Based on that analysis, the Commission approved PEF's

Plan D as reasonable and prudent and held that PEF should recover the prudently incurred costs of implementing the plan.

B. PEF's Plan "D"

PEF's compliance plan (Plan D) meets the applicable environmental requirements by striking a good balance between reducing emissions, primarily through installation of controls on PEF's largest and newest coal units (Crystal River Units 4 and 5), and making strategic use of the allowance markets to comply with CAIR requirements. Specific components of the Plan are summarized below.

1. CAIR SO_2 Plan

The most significant component of PEF's Integrated Clean Air Compliance Plan is the installation of flue gas desulfurization (FGD) systems, also known as wet scrubbers, on Crystal River Units 4 and 5 to comply with CAIR's SO_2 requirements. PEF also plans to purchase limited SO_2 allowances. The plan also includes switching Crystal River Units 1 and 2 to burn low-sulfur (1.2 lbs SO_2/mmBtu) "compliance" coal, and burning low sulfur oil at Anclote Units 1 and 2. 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 along with other relevant fuel selection considerations.

2. CAIR NOx Plan

The primary component of PEF's NOx compliance plan is the installation of low NOx burners (LNBs) and selective catalytic reduction (SCR) systems on Crystal River Units 4 and 5. Currently, the Plan also includes installation of LNB/SOFA controls to reduce NOx emissions from the Anclote units. However, 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. Alternative technology trials and studies for alternative NOx controls are being evaluated to more thoroughly quantify costs, effectiveness, benefits, and risks. Technologies being evaluated for studies and trials include, but are not limited to, selective non-catalytic reduction (SNCR), fuel oil additives, and burner tip modifications. To achieve compliance with CAIR, PEF plans to take strategic advantage of CAIR's cap-and-trade feature by purchasing some annual and ozone season NOx allowances.

3. Mercury Plan

As discussed more fully below, a federal appeals court vacated the federal CAMR regulations in 2008. With CAMR vacated, PEF is not required at this time to install mercury controls to meet the CAMR emission limits. This development does not have any immediate, significant impact on PEF's implementation of Plan D because installation of NOx and SO_2 controls on Crystal River Units 4 and 5 is expected to reduce mercury emissions by at least 80% and the plan did not contemplate installation of any mercury-specific controls until 2017. PEF will continue to monitor the regulatory developments related to utility mercury emissions as well as research and development of mercury control technologies to ensure that the most reliable and cost-effective control technology is used when the time arrives for compliance.

4. CAVR Visibility Plan

PEF operates four units that are potentially subject to Best Available Retrofit Technology (BART) under CAVR, including Anclote Units 1 and 2 and Crystal River Units 1 and 2. As indicated above, PEF's Compliance Plan includes switching to low-sulfur oil and the installation of LNBs at Anclote Units 1 and 2 or other alternative NOx controls such as selective non-catalytic reduction, fuel oil additives, combustion control technologies, and burner tip modifications. Per the FDEP'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. Based on modeled impact of particulate matter on visibility Anclote Units 1 and 2 were determined to be exempt from BART in April 2008. Because the results of the modeling for Crystal River Units 1 and 2 showed visibility impacts at or above regulatory threshold levels, PEF applied for a BART permit for those units. This permit was issued on February 26, 2009 and it establishes a combined BART emission standard for Crystal River Units 1 and 2. By establishing a combined emission standard, the permit enables PEF to cost-effectively satisfy BART requirements by maintaining the existing Unit 1 electrostatic precipitator (ESP) and upgrading the Unit 2 ESP if necessary,

III. Efficacy of PEF's Plan D

As noted above, in its Final Order in Docket No. 070007- EI, the Commission requested a review of the efficacy of PEF's Integrated Clean Air Compliance Plan (Plan D) and the cost-effectiveness of PEF's retrofit options for each generating unit in relation to expected changes in environmental regulations. With regard to Plan D's efficacy, PEF remains confident that Plan D will have the desired effect of achieving timely compliance with the applicable regulations in a cost-effective manner. As noted below, however, there are uncertainties that could affect the timing and costs of implementation.

A. Project Milestones

PEF remains on schedule to complete installation of controls on Crystal River Units 4 and 5 as contemplated in PEF's 2008 ECRC filing. As discussed in previous filings, PEF has executed contracts for specific project components, as well as an overall Engineering, Construction and Procurement (EPC) contract. Since the submittal of last year's annual review, PEF has achieved the following project milestones:

ACHIEVED CAIR COMPLIANCE MILESTONES

Access Road CRN – Common	Apr-08
Chimney Shell Complete – Common	May-08
Limestone Prep steel complete – Common	Jul-08
Scheduled Equipment Delivery complete – Crystal River Unit 4 LNB	Aug-08
FGD building steel complete – Crystal River Unit 5 FGD	Sep-08
SCR Steel complete – Crystal River Unit 5 SCR	Sep-08
SCR Foundation complete – Crystal River Unit 4 SCR	Sep-08
Access Road Piping delivered – Crystal River Unit 4 FGD	Oct-08
Air pre-heater baskets delivered – Crystal River Unit 5 FGD	Dec-08
LNB scheduled equipment delivery complete – Crystal River Unit 5 SCR	Dec-08
Urea equipment delivery – Common	Dec-08
Crystal River Unit 4 LNB Installation complete	Dec-08

PEF expects to achieve the following project milestones in 2009 and 2010:

UPCOMING CAIR COMPLIANCE MILESTONES

FGD building steel delivery complete - Crystal River Unit 4 FGD	Mar-09	
[redacted]	[redacted]	1
[redacted]	[redacted]	2
Limestone handling complete – Common	Sep - 09	
[redacted]	[redacted]	3
SCR Steel erection work complete - Crystal River Unit 4 SCR	Dec-09	
[redacted]	[redacted]	4
[redacted]	[redacted]	5
[redacted]	[redacted]	6

B. Projects Costs

During 2008, PEF had incurred approximately $568 million in capital costs for the Crystal River projects. The 2008 figure includes approximately $511 million in contract billings, $13 million of owner's costs, and $44 million of AFUDC. As of December 2008, the life-to-date capital costs were approximately $897 million. This figure includes approximately $812 million in contract billings, $34 million of owner's costs, and $51 million of AFUDC. The contract billings include payments for: major construction work, design and engineering work, procurement of major equipment, and environmental permits. The overall budget, excluding AFUDC, is $1.15 billion. Currently, the costs are on track to be completed within the overall budget.

C. Uncertainties

While a significant amount of study, engineering, and analysis have been completed and construction has begun on the Crystal River projects, there are still a number of uncertainties that could affect project schedules and costs. Although most of PEF's contracts contain provisions for liquidated damages for delays, the non-performance of contractors, force majeure events, and other uncertainties could adversely impact project schedules and costs. The primary risks identified on the PEF CAIR compliance projects are as follows:

- **EPCR adherence to the outage schedules:** EPCR has finalized the schedule according to the planned outage dates. PEF personnel will monitor the schedule and identify any potential issues.

- **Force Majeure:** There is a risk of a major storm impacting this project considering the location is directly on the Gulf Coast.

- **Scope Modifications:** There are risks of design errors, quantity changes, site conditions, site interferences, change requests or other items which would require additional scope. A project contingency has been developed to cover these unknowns. A process is in place to track these contingencies on a monthly basis in order to trend and project future costs.

- **Condition of Certification (COC) Modification delay:** A lengthy delay in the FDEP's approval of the Gypsum Storage Pad design could create a delay in receiving the necessary modifications to the existing Conditions of Certification for Crystal River Units 4 and 5. This approval is now expected by the end of April 2009.

Primary risks to date are discussed above; however, emergent risks could still occur. Project contingency has been developed to cover these project unknowns, and PEF project staff members are actively engaged to minimize or avoid any project schedule impacts.

IV. Retrofit Options in Relation to Expected Changes in Environmental Regulations

Since PEF's filing in the 2008 ECRC docket, no new or revised environmental regulations have been adopted that have a direct bearing on Plan D. Furthermore, at this time, it is not possible to predict the timing or requirements of any environmental regulations that may be adopted in the future. The following discussion addresses three regulatory developments that have been the topic of discussion since PEF's 2008 filing.

A. Status of CAIR

In July 2008, the U.S. Circuit Court of Appeals for the District of Columbia issued a decision vacating CAIR in its entirety. *North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008). However, in response to EPA's petition for rehearing, the court requested briefs from the parties regarding whether CAIR should be remanded to EPA without vacatur of CAIR. On December 23, the court decided to remand CAIR without vacatur, thereby leaving the rule and its compliance obligations in place. *North Carolina v. EPA*, 550 F.3d 1176 (D.C. Cir. 2008). Thus, PEF must continue to move forward with its Integrated Clean Air Compliance Plan in order to meet the impending CAIR compliance deadlines.

B. Status of CAMR

In February 2008, the U.S. Court of Appeals for the District of Columbia (D.C.) Circuit vacated the federal CAMR regulations. *See, New Jersey v. EPA*, 517 F. 3d 574 (D.C. Cir. 2008). EPA originally promulgated CAMR under Section 111 of the Clean Air Act (CAA), rather than CAA Section 112, which requires EPA to establish Maximum Achievable Control Technology (MACT) standards for hazardous air pollutants. EPA's decision to proceed under CAA Section 111 was based on its rescission of a prior finding in 2000 that emissions of mercury and other hazardous pollutants from electric generating units should be regulated under CAA Section 112. In its decision, the D.C. Circuit court vacated EPA's rescission of its 2000 finding, holding that the CAA required EPA, prior to making such a rescission, to determine that no utility-unit's mercury emissions exceeded a level that would "protect public health with an ample margin of safety and [have] no adverse environmental effect." Based on this threshold conclusion, the court then vacated CAMR because it was based on EPA's rescission. Since last year's filing, the U.S. Supreme Court has denied review of the D.C. Circuit's vacatur of CAMR and EPA has announced its intention to proceed with a MACT rulemaking.

It is impossible to predict when EPA will complete the MACT rulemaking process or what the emissions standards will be. In any event, because PEF's Plan D relies on the co-benefit of SCR/scrubbers rather than mercury-specific controls until 2017, the Plan provides flexibility to respond to any rules EPA may adopt in response to the D.C. Circuit's decision.

C. Potential Greenhouse Gas Regulation

When PEF committed to placing environmental controls on Crystal River Units 4 and 5, climate change issues were only beginning to be discussed. At that time, PEF had to commit to installing controls in order to meet the fast approaching 2009 and 2010 CAIR compliance deadlines. Governor Crist subsequently issued Executive Order 07-127 directing FDEP to promulgate regulations requiring reductions in utility carbon dioxide (CO_2) emissions. In addition, the 2008 Florida Legislature enacted legislation authorizing FDEP to adopt rules establishing a cap-and-trade program and requiring FDEP to submit any such rules for legislative review and ratification. At this time, however, FDEP is still in the early stages of developing cap-and-trade rules and numerous key issues remain unresolved, such as the approach to allowance distribution and whether Florida should join a regional program; a rulemaking workshop was held on March 11, 2009. Until such regulations are adopted and ratified, or legislation is enacted at the federal level, the potential impact of CO_2 regulation will remain uncertain. Nevertheless, PEF is taking steps to reduce CO_2 emissions consistent with the state's goals. In December 2008, the Company announced an agreement with FDEP to retire Crystal River Units 1 and 2 coal-fired units after the second of two new, advanced design nuclear units in Levy County completes its first fuel cycle. Retiring the coal-fired Crystal River Units 1 and 2 will reduce PEF's CO_2 emissions by 5 million tons per year.

At this time, there are still no retrofit options commercially available to reduce CO_2 emissions from fossil fuel-fired electric generating units such as Crystal River Units 4 and 5, which are the primary focus of PEF's compliance plan. To date, there have been no large-scale commercial carbon capture and sequestration technology demonstrations on electric utility units. Until numerous technological, regulatory and liability issues are resolved, it will be impossible to determine whether carbon capture and storage would be a technically feasible or cost-effective means of complying with a CO_2 regulatory regime. Likewise, replacing coal-fired generation from Crystal River Units 4 and 5 with lower CO_2-emitting natural gas-fired combined cycle generation[1] is not a viable option. PEF has already incurred over 73% of the costs, excluding

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[1] The CO_2 emission rate for natural gas-fired combined cycle (NG/CC) units is approximately 50% of the emission rate for coal-fired generating units. Thus, replacing coal-fired generation with NG/CC would not eliminate costs associated with any to-be-adopted CO_2 regulatory regime.

AFUDC, of Plan D and the major components of the Plan are due to be placed in service in 2009 and 2010. Even if PEF could abandon the Crystal River projects at this late date, sufficient combined-cycle generation could not be placed on-line until the 2015-2016 timeframe. PEF would have to rely solely on allowance markets to achieve and maintain CAIR compliance for five to six years until the combined cycle generation could be placed in service. Given the uncertainty of the CAIR allowance markets, PEF cannot reasonably assume sufficient allowances would be available at reasonable price if PEF were left in the extremely vulnerable position of relying solely on allowance purchases to achieve compliance. Furthermore, replacing Crystal River Units 4 and 5 with gas-fired generation would decrease PEF's fuel diversity and potentially increase fuel price volatility.

V. Conclusion

Based on project milestones achieved to date, PEF remains confident that Plan D will have the desired effect of achieving timely compliance with the applicable regulations in a cost-effective manner. No new or revised environmental regulations have been adopted that have a direct bearing on PEF's compliance plan. Although FDEP is in the process of developing a cap-and-trade program to regulate CO_2 emissions, no regulations have been adopted to date and there currently are no demonstrated retrofit options to reduce CO_2 emissions from fossil fuel-fired electric generating units. Moreover, abandoning the Crystal River Units 4 and 5 emission control projects is not a viable option in light of the imminent 2009 and 2010 CAIR deadlines. Although EPA is proceeding with the adoption of new MACT standards for utility hazardous air pollutant emissions as a result of a federal court decision vacating the federal CAMR rules, this development does not immediately impact PEF's implementation of Plan D because the plan relies primarily on installation of NOx and SO_2 controls to reduce mercury emissions and does not contemplate installation of mercury-specific controls until 2017. For these reasons, PEF's Plan D continues to represent the most cost-effective alternative for achieving and maintaining compliance with the applicable regulatory requirements.

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TECO's Responses to Staff's First Set of Interrogatories (Nos. 1-8)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Factors.	)))	DOCKET NO. 090007-EI FILED: APRIL 6, 2009

TAMPA ELECTRIC COMPANY'S

ANSWERS TO FIRST SET OF INTERROGATORIES (NOS. 1 - 8)

OF THE

FLORIDA PUBLIC SERVICE COMMISSION

Tampa Electric files its Answers to Interrogatories (Nos. 1 - 8) propounded and served on March 16, 2009, by the Florida Public Service Commission.

TAMPA ELECTRIC COMPANY
DOCKET NO. 090007-EI
INDEX TO STAFF'S FIRST SET OF INTERROGATORIES (NOS. 1 - 8)

Number	Witness	Subject	Bates Stamped Page
1	Carpinone	Please use following table to provide information regarding TECO's generating facilities and their air emission monitoring and control measures. Please use the keys to fill column (4), (7), (9), (12), and (14), and provide the definition of each key. E.g., B=base load, I=intermediate load, LNB=low NOx burner, SCR=selective catalytic reduction, etc.	1
2	Carpinone	On Wednesday, February 11, 2009, one of TECO's coal-fired units of the 1,800 MW power plant near Apollo Beach in the Big Bend area unexpectedly went off-line, causing a cloud of coal dust to be released from the smokestack. The cloud quickly dissipated, and the filters from the monitors of the Environmental Protection Commission of Hillsborough County were sent to a lab for testing. Regarding this incident, please provide the following information: a) The impacts on the public health and the environment due to the reported ash and coal dust discharge; b) A brief of the testing results; c) Related ECRC costs, if any; and d) ECRC costs, if any, towards the improvement of the air pollutant discharge prevention for the generating unit on which the incident happened and other similar units.	3
3	Carpinone	Please fill out the following table to provide general information regarding each ash pond used for each of TECO's coal generation units.	4
4	Carpinone	Please explain what Federal/State/Municipal rules, regulations or permits govern TECO's management of the safety of its ash ponds.	6
5	Carpinone	Please fill out the following table to provide general information regarding each gypsum pond used for each of TECO's coal generation units.	7
6	Carpinone	Please explain what Federal/State/Municipal rules, regulations or permits govern TECO's management of the safety of its gypsum ponds.	8
7	Carpinone	Please fill out the following table to provide general information regarding each landfill used for each of TECO's generation units.	9
8	Carpinone	Please explain what Federal/State/Municipal rules, regulations or permits govern TECO's management of the safety of its landfills.	10

Paul Carpinone
Director, Environmental
Tampa Electric Company
702 N. Franklin St.
Tampa, FL 33602

1. Please use following table to provide information regarding TECO's generating facilities and their air emission monitoring and control measures. Please use the keys to fill column (4), (7), (9), (12), and (14), and provide the definition of each key. E.g., B=base load, I=intermediate load, LNB=low NOx burner, SCR=selective catalytic reduction, etc.

TECO's Generating Facilities and their Air Emission Monitoring & Control Measures

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
						SO_2, NOx, Hg, CO_2 and Particulate Matter Monitoring					SO_2, NOx, Hg, CO_2 & Particulate Matter Emission Controlling				
Plant Name	Unit No.	Unit Type	Operating Mode	Net Summer Capacity	Commercial In-Service Month/Year	Existing Equipment/ Technology	In Operation (Yes/No)	Equipment/Technology Under Construction	In Service Date	ECRC Project No.	Existing System/ Technology	In Operation (Yes/No)	System/Technology Under Construction	In Service Date	ECRC Project No.

A. See the attached table.

Tampa Electric's Generating Facilities and their Air Emission Monitoring & Control Measures

						SO_2, NOx, Hg, CO_2 and Particulate Matter Monitoring					SO_2, NOx, Hg, CO_2 and Particulate Matter Emission Controlling				
Plant Name	Unit No.	Unit Type	Operating Mode	Net Summer Capacity	Commercial In-Service Month/Year	Existing Equipment/ Technology	In Operation (Yes/No)	Equipment/ Technology Under Construction	In-Service Date	ECRC Project No.	Existing System/ Technology	In Operation (Yes/No)	System/ Technology Under Construction	In-Service Date	ECRC Project No.
Big Bend	1	ST	Base	379	Oct-70	CEMS	YES	NA	Nov-93	NA	ESP, FGD	YES	NA	Jan-00	NA
Big Bend	2	ST	Base	373	Apr-73	CEMS	YES	NA	Nov-93	NA	SCR, ESP, FGD	YES	NA	May-09	NA
Big Bend	3	ST	Base	381	May-76	CEMS	YES	NA	Nov-93	NA	SCR, ESP, FGD	YES	NA	May-08	NA
Big Bend	4	ST	Base	417	Feb-85	CEMS	YES	NA	Nov-93	NA	SCR, ESP, FGD	YES	NA	May-07	NA
Big Bend	1	CT	Peak	10	Feb-69	CEMS	YES	NA	Jan-95	NA	NA	NA	NA	NA	NA
Bayside	1	CC	Base	701	Apr-03	CEMS	YES	NA	Apr-03	NA	SCR, LNB	YES	NA	Apr-03	NA
Bayside	2	CC	Base	1,006	Jan-04	CEMS	YES	NA	Jan-04	NA	SCR, LNB	YES	NA	Jan-04	NA
City of Tampa	1	IC	Peak	3	Apr-01	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
City of Tampa	2	IC	Peak	3	Apr-01	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Phillips	1	IC	Peak	18	Jun-83	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Phillips	2	IC	Peak	18	Jun-83	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Polk	1	IGCC	Base	235	Sep-96	CEMS	YES	NA	Sep-96	NA	NA	NA	NA	NA	NA
Polk	2	GT	Peak	158	Jul-00	CEMS	YES	NA	Jul-00	NA	NA	NA	NA	NA	NA
Polk	3	GT	Peak	158	May-02	CEMS	YES	NA	May-02	NA	NA	NA	NA	NA	NA
Polk	4	GT	Peak	151	Mar-07	CEMS	YES	NA	Mar-07	NA	LNB	YES	NA	Mar-07	NA
Polk	5	GT	Peak	151	Apr-07	CEMS	YES	NA	Apr-07	NA	LNB	YES	NA	Apr-07	NA

Note: In-service dates for Big Bend Units 2-4 controls correlate to the SCR in-service dates.

TAMPA ELECTRIC COMPANY
DOCKET NO. 090007-EI
STAFF'S FIRST SET OF
INTERROGATORIES
INTERROGATORY NO. 1
PAGE 2 OF 2
FILED: APRIL 6, 2009

2

090007 Hearing Exhibit - 00002902

2. On Wednesday, February 11, 2009, one of TECO's coal-fired units of the 1,800 MW power plant near Apollo Beach in the Big Bend area unexpectedly went off-line, causing a cloud of coal dust to be released from the smokestack. The cloud quickly dissipated, and the filters from the monitors of the Environmental Protection Commission of Hillsborough County were sent to a lab for testing. Regarding this incident, please provide the following information:

a) The impacts on the public health and the environment due to the reported ash and coal dust discharge;
b) A brief of the testing results;
c) Related ECRC costs, if any; and
d) ECRC costs, if any, towards the improvement of the air pollutant discharge prevention for the generating unit on which the incident happened and other similar units.

A. a) Due to the brief period of less than one minute in which the coal dust was released, there has been no reported evidence of any impact to the public health or environment.

b) Tampa Electric has requested, but not received, the results of any testing conducted by the Hillsborough County Environmental Protection Commission.

c) Not applicable.

d) Not applicable.

3. Please fill out the following table to provide general information regarding each ash pond used for each of TECO's coal generation units.

Plant Name /Unit No.					
Ash pond used					
Capacity of the pond					
Location of the pond					
Date of the last inspection					
Inspection findings					
Remedies implemented to address the findings					
Scheduled date for the next inspection					
Safety control measures employed/ to be implemented					
Related ECRC project					
Associated costs recovered (and year) through the ECRC					

A. See the attached table.

Plant Name /Unit No.	Big Bend 4	Big Bend 4	Big Bend 4	Big Bend 4	Big Bend 4
Ash pond used	North Flyash	South Flyash	Long Term Flyash	North Bottom Ash	South Bottom Ash
Capacity of the pond (yd^3)	161,250	222,250	155,000	233,000	303,000
Location of the pond	Big Bend Station	Big Bend Station	Big Bend Station	Big Bend Station	Big Bend Station
Date of the last inspection	01/09	01/09	01/09	01/09	01/09
Inspection findings	Satisfactory	Satisfactory	Satisfactory	Satisfactory	Satisfactory
Remedies implemented to address the findings	Not Required	Not Required	Not Required	Not Required	Not Required
Scheduled date for the next inspection	None Scheduled	None Scheduled	None Scheduled	None Scheduled	None Scheduled
Safety control measures employed/ to be implemented	Monthly inspections for water level control/ Liner system	Monthly inspections for water level control/ Liner system	Monthly inspections for water level control/ Liner system	Monthly inspections for water level control/ Liner system	Monthly inspections for water level control/ Liner system
Related ECRC project	None	None	None	None	None
Associated costs recovered (and year) through the ECRC	NA	NA	NA	NA	NA

4. Please explain what Federal/State/Municipal rules, regulations or permits govern TECO's management of the safety of its ash ponds.

A. The Big Bend ash ponds are governed by the Florida Department of Environmental Protection rules for Solid Waste, Chapter 62-701 F.A.C. and Industrial Wastewater, Chapter 62-620 F.A.C. These ponds are exempt from full regulation as solid waste due to the stored materials' status as non-hazardous industrial byproducts, which may be recycled for beneficial reuse. These management units are authorized under Site Certification PA 79-12 for Big Bend Unit 4.

5. Please fill out the following table to provide general information regarding each gypsum pond used for each of TECO's coal generation units.

Plant Name /Unit No.					
Gypsum pond used					
Capacity of the pond					
Location of the pond					
Date of the last inspection					
Inspection findings					
Remedies implemented to address the findings					
Scheduled date for the next inspection					
Safety control measures employed/ to be implemented					
Related ECRC project					
Associated costs recovered (and year) through the ECRC					

A. Tampa Electric does not operate any gypsum ponds. Dry gypsum is conveyed from Big Bend Station to a gypsum pile for management and beneficial reuse. See the company's response to Interrogatory No. 6 regarding regulatory information.

6. Please explain what Federal/State/Municipal rules, regulations or permits govern TECO's management of the safety of its gypsum ponds.

A. The Big Bend gypsum pile is governed by the Florida Department of Environmental Protection rules for Solid Waste, Chapter 62-701 F.A.C. and Industrial Wastewater, Chapter 62-620 F.A.C. The gypsum pile is exempt from full regulation as solid waste due to its status as a non-hazardous industrial byproduct that is recycled for beneficial reuse. This management unit is authorized under Site Certification PA 79-12 for Big Bend Unit 4.

7. Please fill out the following table to provide general information regarding each landfill used for each of TECO's generation units.

Plant Name /Unit No.					
Landfill used					
Size of the landfill					
Location of the landfill					
Date of the last inspection					
Inspection findings					
Remedies implemented to address the findings					
Scheduled date for the next inspection					
Safety control measures employed/ to be implemented					
Related ECRC project					
Associated costs recovered (and year) through the ECRC					

A. Tampa Electric does not operate any landfills at any of its facilities.

8. Please explain what Federal/State/Municipal rules, regulations or permits govern TECO's management of the safety of its landfills.

A. Tampa Electric does not operate any landfills at any of its facilities.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Dawn Wurtenburg who deposed and said that she is Regulatory Analyst, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's First Set of Interrogatories, (Nos. 1 - 8) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 3rd day of April, 2009.

Dawn Wurtenburg

Sworn to and subscribed before me this 3rd day of April, 2009.

Brenda L. Irizarry

My Commission expires Notary Public State of Florida Brenda Lee Irizarry My Commission DD551587 Expires 07/29/2010

38

TECO's Responses to Staff's Second Set of Interrogatories (Nos. 9)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Factors.	)))	DOCKET NO. 090007-EI FILED: MAY 4, 2009

TAMPA ELECTRIC COMPANY'S

ANSWERS TO SECOND SET OF INTERROGATORIES (NO. 9)

OF THE

FLORIDA PUBLIC SERVICE COMMISSION

Tampa Electric files its Answers to Interrogatories (No. 9) propounded and served on April 14, 2009, by the Florida Public Service Commission.

MAY - 4 2009

TAMPA ELECTRIC COMPANY
DOCKET NO. 090007-EI
INDEX TO STAFF'S SECOND SET OF INTERROGATORIES (NO. 9)

Number	Witness	Subject	Bates Stamped Page
9	Bryant	Referring to the testimony of Howard Bryant dated April 1, 2009, please provide a schedule that shows the capital structure, components, and cost rates relied upon for calculating the revenue requirement rate of return. Please include in this schedule the derivation of debt and equity components used in the Return on Average Net Investment, lines 7 (a) and (b), on Form 42-8A attached to the testimony. Please cite all sources and include the rationale for using the particular capital structure and cost rates.	1

Howard Bryant
Manager, Rates
Tampa Electric Company
702 N. Franklin St.
Tampa, FL 33602

9. Referring to the testimony of Howard Bryant dated April 1, 2009, please provide a schedule that shows the capital structure, components, and cost rates relied upon for calculating the revenue requirement rate of return. Please include in this schedule the derivation of debt and equity components used in the Return on Average Net Investment, lines 7 (a) and (b), on Form 42-8A attached to the testimony. Please cite all sources and include the rationale for using the particular capital structure and cost rates.

A. The following schedule shows the derivation of the debt and equity components for lines 7(a) and (b) on Form 42-8A.

Last FPSC Capital Structure and Cost Rates
Based on 11.75% ROE

	Amount ($)	Ratio (%)	Cost Rate (%)	Weighted Cost (%)
Long Term Debt	558,899	30.08	7.81	2.35
Short Term Debt	56,194	3.02	5.37	0.16
Preferred Stock	45,539	2.45	6.49	0.16
Customer Deposits	43,512	2.34	7.86	0.18
Common Equity [1]	801,028	43.12	11.75	5.07
Deferred ITC - Weighted Cost	59,035	3.18	10.01	0.32
Accumulated Deferred Income Taxes & Zero Cost ITCs	293,667	15.81	0.00	0.00
Total	**1,857,874**	**100.00**		**8.2392**

[1] Effective January 1, 1995 per FPSC Order No. PSC-95-0580-FOF-EI, Docket No. 950379-EI.

ITC split between Debt and Equity:

	Amount ($)	Ratio (%)
Long Term Debt	558,899	39.77
Equity - Preferred	45,539	3.24
Equity - Common	801,028	56.99
Total	**1,405,466**	**100.00**

Deferred ITC - Weighted Cost:

Debt	=.32% * 39.77%	0.13%
Equity	=.32% * 60.23%	0.19%
	Weighted Cost	**0.32%**

Total Equity Cost Rate:

Preferred Stock	0.16%
Common Equity	5.07%
Deferred ITC - Weighted Cost	0.19%
Sum	5.42%
Tax Multiplier	1.628002
Total Equity Component	**8.8238%**

Total Debt Cost Rate:

Long Term Debt	2.35%
Short Term Debt	0.16%
Customer Deposits	0.18%
Deferred ITC - Weighted Cost	0.13%
Total Debt Component	**2.82%**

A F F I D A V I T

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Dawn Wurtenburg who deposed and said that she is Regulatory Analyst, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Second Set of Interrogatories, (No. 9) prepared or assisted with the responses to these Interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 1st day of May, 2009.

Dawn Wurtenberg

Sworn to and subscribed before me this 1st day of May, 2009.

Brenda L. Irizarry

My Commission expires

Notary Public State of Florida
Brenda Lee Irizarry
My Commission DD551587
Expires 07/29/2010

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TECO's Responses to Staff's Third Set of Interrogatories (Nos. 10-11)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Factors.	)))	DOCKET NO. 090007-EI FILED: SEPTEMBER 10, 2009

TAMPA ELECTRIC COMPANY'S

ANSWERS TO THIRD SET OF INTERROGATORIES (NOS. 10-11)

OF THE

FLORIDA PUBLIC SERVICE COMMISSION

Tampa Electric files its Answers to Interrogatories (Nos. 10-11) propounded and served on August 21, 2009, by the Florida Public Service Commission.

TAMPA ELECTRIC COMPANY
DOCKET NO. 090007-EI
INDEX TO STAFF'S THIRD SET OF INTERROGATORIES (NOS. 10 - 11)

Number	Witness	Subject	Bates Stamped Page
10	Bryant	For purposes of the following request, please refer to the testimony of TECO witness Bryant filed on August 3, 2009, page 6, lines 9-16. Please explain the cause of the decrease in the usage of ammonia in Big Bend Unit 3 SCR and Unit 4 SCR.	1
11	Bryant	For purposes of the following request, please refer to the testimony of TECO witness Bryant filed on August 3, 2009, page 6, lines 17-25. (a) Please explain the cause of the delay of commercial operation. (b) What was the original projected commercial operation date? (c) What is the current projected commercial operation date?	2

Howard Bryant
Manager, Rates
Tampa Electric Company
702 N. Franklin St.
Tampa, FL 33602

10. For purposes of the following request, please refer to the testimony of TECO witness Bryant filed on August 3, 2009, page 6, lines 9-16. Please explain the cause of the decrease in the usage of ammonia in Big Bend Unit 3 SCR and Unit 4 SCR.

A. The decrease in the usage of ammonia for Big Bend Unit 3 SCR and Unit 4 SCR was due to system outages that were not originally anticipated. In addition to the decrease in usage of ammonia, the unit cost has also decreased. This lower cost is anticipated to continue through the remainder of the year.

11. For purposes of the following request, please refer to the testimony of TECO witness Bryant filed on August 3, 2009, page 6, lines 17-25.

(a) Please explain the cause of the delay of commercial operation.
(b) What was the original projected commercial operation date?
(c) What is the current projected commercial operation date?

A. (a) Steam turbine issues prevented the completion of performance testing associated with the turnover of the Big Bend Unit 2 SCR assets to plant operations. These issues have been resolved and final testing is expected to be complete by September 4, 2009.

(b) The original projected commercial operation date was May 1, 2009.

(c) Big Bend Unit 2 SCR began commercial operation September 4, 2009.

A F F I D A V I T

STATE OF FLORIDA)
)
COUNTY OF HILLSBOROUGH)

Before me the undersigned authority personally appeared Dawn Wurtenburg who deposed and said that she is Regulatory Analyst, Tampa Electric Company, and that the individuals listed in Tampa Electric Company's response to Staff's Third Set of Interrogatories, (Nos. 10 - 11) prepared or assisted with the responses to these interrogatories to the best of her information and belief.

Dated at Tampa, Florida this 9th day of September, 2009.

Dawn M Wurtenberg

Sworn to and subscribed before me this 9th day of September, 2009.

Cynthia Roy Kyle

NOTARY PUBLIC STATE OF FLORIDA
Notary Public State of Florida
Cynthia Roy Kyle
My Commission DD645902
Expires 03/01/2011

My Commission expires ______________________

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TECO's Responses to Staff's First Request for Production of Documents (No. 1)

BEFORE THE

FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Factors.	)))	**DOCKET NO. 090007-EI** **FILED: OCTOBER 12, 2009**

TAMPA ELECTRIC COMPANY'S

ANSWERS TO FIRST REQUEST FOR

PRODUCTION OF DOCUMENTS (NO. 1)

OF THE

FLORIDA PUBLIC SERVICE COMMISSION STAFF

Tampa Electric files this its Answers to Production of Documents (No.1) propounded and served on September 21, 2009, by the Florida Public Service Commission Staff.

1. Referring to the testimony of Howard T. Bryant dated August 28, 2009, please provide a schedule that shows the capital structure, components, and cost rates relied upon for calculating the revenue requirement rate of return. Please include in this schedule the derivation of debt and equity components used in the Return on Average Net Investment, lines 7 (a) and (b), on Form 42-4P attached to the testimony. Please cite all sources and include the rationale for using the particular capital structure and cost rates.

A.

Tampa Electric Company
Environmental Cost Recovery Clause
Calculation of Revenue Requirement Rate of Return

Based on 11.25% ROE

		Jurisdictional Rate Base 2009 Test Year ($000)[A]	Ratio (%)[B]	Cost Rate (%)[1]	Weighted Cost (%)[C]	Revenue Req't Rate (%)[D]	Monthly Revenue Req't Rate (%)[E]
1	Long Term Debt	1,384,999	40.29	6.80	2.7397	2.7397	0.2283
2	Short Term Debt	7,905	0.23	2.75	0.0063	0.0063	0.0005
3	Preferred Stock	0	0.00	0.00	0.0000	0.0000	0.0000
4	Customer Deposits	99,502	2.89	6.07	0.1754	0.1754	0.0146
5	Common Equity	1,632,612	47.49	11.25	5.3426	8.6978	0.7248
6	Deferred ITC - Weighted Cost	8,964	0.26	9.19	0.0239	0.0320	0.0027
7	Accumulated Deferred Income Taxes & Zero Cost ITCs	303,629	8.83	0.00	0.0000	0.0000	0.0000
8	**Total**	3,437,611	100.00		8.2879	11.6512	0.9709

[A] From Order PSC-09-00571-FOF-EI.
[B] Jurisdictional Rate Base divided by Total Rate Base.
[C] Ratio Percent multiplied by Cost Rate Percent.
[D] Same as Weighted Cost Rate except for equity components. Equity Components = Weighted Cost Rate divided by (1- 0.38575). Where 0.38575 is the effective Income Tax Rate.
[E] Revenue Requirement Rate divided by 12.

TAMPA ELECTRIC COMPANY
DOCKET NO. 090007-EI
STAFF'S FIRST REQUEST FOR
PRODUCTION OF DOCUMENTS
DOCUMENT NO. 1

FILED: OCTOBER 12, 2009

ITC Component:

		Jurisdictional Rate Base ($000)[1]	Ratio (%)[2]	Cost Rate (%)[1]	Weighted Cost (%)[3]
9	Long Term Debt	1,384,999	45.78	6.80	3.1128
10	Short Term Debt	7,905	0.26	2.75	0.0072
11	Equity - Preferred	0	0.00	0.00	0.0000
12	Equity - Common	1,632,612	53.96	11.25	6.0706
13	**Total**	**3,025,516**	**100.00**		**9.1906**

Breakdown of Revenue Requirement Rate between Debt and Equity:

		Revenue Req't Rate (%)[4]	Monthly Revenue Req't Rate (%)[5]
14	Total Debt Component (Sum of Lines 1,2,4,17 and 18)	2.9324	0.2444
15	Total Equity Component (Sum of Lines 3,5,19 and 20)	8.7188	0.7266
16	Total Revenue Requirement Rate of Return	**11.6512**	**0.9709**

Breakdown of Revenue Requirement Rate for ITC Component:

		Ratio (%)[2]	Weighted Cost (%)[3]	Revenue Req't Rate (%)[4]
17	Long Term Debt	45.78	0.0239	0.0109
18	Short Term Debt	0.26	0.0239	0.0001
19	Equity - Preferred	0.00	0.0239	0.0000
20	Equity - Common	53.96	0.0239	0.0210
21	**Total**	**100.00**		**0.0320**

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PSC's Audit Report for TECO

FLORIDA PUBLIC SERVICE COMMISSION

DIVISION OF REGULATORY COMPLIANCE
BUREAU OF AUDITING

TAMPA DISTRICT OFFICE

TAMPA ELECTRIC COMPANY

ENVIRONMENTAL COST RECOVERY CLAUSE AUDIT

HISTORICAL YEAR ENDED DECEMBER 31, 2008

DOCKET NO. 090007-EI

AUDIT CONTROL NO. 09-012-2-2

Tomer Kopelovich, Audit Manager

Joseph W. Rohrbacher, Tampa District Supervisor

DOCUMENT NUMBER-DATE
05893 JUN 12 8
FPSC-COMMISSION CLERK

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DIVISION OF REGULATORY COMPLIANCE
AUDITOR'S REPORT

May 29, 2008

TO: FLORIDA PUBLIC SERVICE COMMISSION AND OTHER INTERESTED PARTIES

We have performed the procedures enumerated later in this report to meet the agreed upon objectives set forth by the Division of Economic Regulation in its audit service request. We have applied these procedures to the attached schedules prepared by Tampa Electric Company (TEC) in support of its filing for Environmental Cost Recovery in Docket 090007-EI.

This audit was performed following general standards and field work standards found in the AICPA Statements on Standards for Attestation Engagements. This report is based on agreed upon procedures and the report is intended only for internal Commission use.

OBJECTIVES AND PROCEDURES:

Objective: Verify all negative depreciation expense amounts reported by TEC for any of its Environmental Cost Recovery Clause (ECRC) projects regardless of whether the negative depreciation expense amount is shown or noted on Form 42-8A of the company filing. Review TEC's justification for each negative depreciation amount including applicable company workpapers.

Procedures: We requested that the company provide instances of negative depreciation recorded during the audit period. The Company responded that there was no negative depreciation for any of the ECRC projects in 2008. Also, we scanned the filing and we did not find any negative depreciation.

Objective: Using sampling procedures, reconcile Plant In Service (PIS) (line 2) and Depreciation Expense (line 8a) for the capital projects listed in Form 42-8A. Verify that the investment is recorded in the correct plant account(s). Verify that the most recent Commission approved depreciation rate(s) or amortization period(s) is used in calculating the depreciation/amortization expense (line 8a, 8b). Verify that dismantlement expense (line 8c) is not included in the depreciation expense (line 8b and line 3).

Procedures: We reconciled Plant In Service, per filing, to the General Ledger. Staff examined a summary of ECRC capital expenditures for 2008. We judgmentally selected various projects for further analysis. This analysis included the examination of selected company expenditures. The expenditures were extracted from the general ledger using queries. The queries listed all capital expenditures for designated FERC accounts, subpoints and resources applicable to ECRC. Based upon dollar amount, several items were selected for testing. The testing included tracing amounts to vendor vouchers to determine if items purchased were properly includible as ECRC investment.

Using beginning and end of period PIS balances by project and by account, we calculated average PIS for the year and applied PSC authorized depreciation rates (Order No. PSC-08-0014-PAA-EI). We compared the resulting computation to the depreciation expense recorded by the company. The company calculated depreciation expense based upon the monthly average of PIS. We determined that no dismantlement expense is included in depreciation expense.

Objective: Verify that where an ECRC project involves the replacement of existing plant assets, the company is retiring the installed costs of replaced units of property according to Rule 25-6.0142(4)(b), F.A.C. [Book cost of retirement shall be credited to plant and debited to accumulated depreciation; cost of removal shall be debited to accumulated depreciation].

Procedures: We requested that the company provide a schedule and supporting documentation for all units of property replacing retired plant. We determined that there was no replacement of existing plant for any of the ECRC projects in 2008.

Objective: Verify calculations of the monthly depreciation expense offsets required by Order No. PSC-99-2513-FOF-EI to adjust ECRC costs for retirements and replacements recovered through base rates.

Procedures: We determined that all ECRC Plant was placed in service subsequent to TEC's 1991 rate case in Docket No. 920324-EI. As a result, there is no ECRC PIS being recovered through base rates and no adjustment is necessary to be in compliance with Commission Order PSC-99-2513-FOF-EI.

Objective: Verify the accuracy of recoverable Operation and Maintenance (O&M) expenses recorded in the ECRC filing.

Reconcile actual O&M project costs for a statistical sample or judgment sample of the O&M projects listed in Form 42-5A.

Procedures: Using judgmental sampling, we traced selected O&M costs for the projects listed in Form-42-5A. The sample items were taken from general ledger queries for ECRC accounts, sub accounts and resource codes.

Objective: List the monthly SO2 allowance expenses for 2008 including revenues, inventory amounts (tonnages and dollars), expensed amounts (tonnages and dollars), and the amount included in working capital.

Procedures: We obtained inventory schedules for SO2 allowances for each month in the test period and selected six months (April, May, July, August, October, and November) for testing. We traced SO2 allowance expense to SO2 emissions from market based sales, co-generation purchases and consumption.

Objective: To verify that True-Up and Interest were properly calculated.

Procedures: We recomputed the 2008 ECRC True-Up and Interest using the approved recoverable True-Up amount per Commission Order PSC-07-0922-FOF-EI and 30-day commercial interest rates.

Objective: Verify the accuracy of recoverable revenues recorded in the ECRC filing.

Procedures: Using KWH's for recoverable sales and Commission approved ECRC rates, we recalculated 2008 ECRC revenues billed. We compared this balance to the ECRC filing.

Form 42 - 2A

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2008 to December 2008

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 Total
1.	ECRC Revenues (net of Revenue Taxes)	$1,638,579	$1,370,190	$1,402,163	$1,497,358	$1,604,847	$1,896,228	$1,838,115	$1,859,793	$1,976,888	$1,751,627	$1,464,969	$1,484,593	$19,785,350
2.	True-Up Provision	(189,293)	(189,293)	(189,293)	(189,293)	(189,293)	(189,293)	(189,293)	(189,293)	(189,293)	(189,293)	(189,293)	(189,287)	(2,271,510)
3.	ECRC Revenues Applicable to Period (Lines 1 + 2)	1,449,286	1,180,897	1,212,870	1,308,065	1,415,554	1,706,935	1,648,822	1,670,500	1,787,595	1,562,334	1,275,676	1,295,306	17,513,840
4.	Jurisdictional ECRC Costs													
	a. O & M Activities (Form 42-5A, Line 9)	934,271	952,608	(142,256)	828,339	63,219	997,223	(77,784)	1,171,490	(1,883,087)	1,590,404	(3,475,832)	1,714,251	2,672,846
	b. Capital Investment Projects (Form 42-7A, Line 9)	2,134,304	2,110,308	2,120,016	2,105,726	2,116,026	2,149,067	2,919,008	3,010,781	3,014,505	3,029,460	3,035,487	3,067,296	30,811,984
	c. Total Jurisdictional ECRC Costs	3,068,576	3,062,916	1,977,760	2,934,065	2,179,245	3,146,290	2,841,224	4,182,271	1,131,418	4,619,864	(440,345)	4,781,547	33,484,830
5.	Over/Under Recovery (Line 3 - Line 4c)	(1,619,289)	(1,882,019)	(764,890)	(1,626,000)	(763,691)	(1,439,355)	(1,192,402)	(2,511,771)	656,177	(3,057,530)	1,716,021	(3,486,241)	(15,970,990)
6.	Interest Provision (Form 42-3A, Line 10)	31,846	20,427	16,266	13,326	10,676	8,020	5,778	2,398	1,353	(1,876)	(1,950)	(1,489)	104,773
7.	Beginning Balance True-Up & Interest Provision	(2,271,510)	(3,669,660)	(5,341,959)	(5,901,290)	(7,324,671)	(7,888,393)	(9,130,435)	(10,127,766)	(12,447,846)	(11,601,023)	(14,471,139)	(12,567,774)	(2,271,510)
	a. Deferred True-Up from January to December 2005 (Order No. PSC-xx-xxxx-FOF-EI)	12,464,395	12,464,395	12,464,395	12,464,395	12,464,395	12,464,395	12,464,395	12,464,395	12,464,395	12,464,395	12,464,395	12,464,395	12,464,395
8.	True-Up Collected/(Refunded) (see Line 2)	189,293	189,293	189,293	189,293	189,293	189,293	189,293	189,293	189,293	189,293	189,293	189,287	2,271,510
9.	End of Period Total True-Up (Lines 5+6+7+7a+8)	8,794,735	7,122,436	6,563,105	5,139,724	4,576,002	3,333,960	2,336,629	16,649	863,372	(2,006,743)	(103,379)	(3,401,822)	(3,401,822)
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)	$8,794,735	$7,122,436	$6,563,105	$5,139,724	$4,576,002	$3,333,960	$2,336,629	$16,649	$863,372	($2,006,743)	($103,379)	($3,401,822)	($3,401,822)

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090007 Hearing Exhibit - 00002934

EXHIBIT 1

Form 42 - 5A

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2008 to December 2008

O&M Activities
(In Dollars)

Line	Description	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July
1.	Description of O&M Activities							
a.	Big Bend Unit 3 Flue Gas Desulfurization Integration	$248,401	$275,121	$243,730	$227,130	$290,194	$337,808	$331,165
b.	Big Bend Units 1 & 2 Flue Gas Conditioning	0						
c.	SO_2 Emissions Allowances	11,881	28,579	(953,364)	17,936	(985,484)	12,269	(1,433,367)
d.	Big Bend Units 1 & 2 FGD	423,620	382,952	348,081	421,332	449,234	496,635	669,195
e.	Big Bend PM Minimization and Monitoring	55,967	32,902	21,123	23,341	20,830	30,439	14,092
f.	Big Bend NO_x Emissions Reduction	125,150	178,174	21,314	0	33,096	66,702	51,277
g.	NPDES Annual Surveillance Fees	34,500	0	0	0	0	0	0
h.	Gannon Thermal Discharge Study	0	0	25,195	12,362	10,997	3,450	0
i.	Polk NO_x Reduction	6	4,220	4,656	2,347	1,721	1,717	5,849
j.	Bayside SCR and Ammonia	6,054	6,852	8,489	0	23,366	0	24,956
k.	Big Bend Unit 4 SOFA	0	17,661	(17,661)	0	52,492	(19,516)	(32,976)
l.	Big Bend Unit 1 Pre-SCR	0	0	0	0	0	0	0
m.	Big Bend Unit 2 Pre-SCR	0	0	0	0	6,188	0	0
n.	Big Bend Unit 3 Pre-SCR	2	0	0	0	0	0	0
o.	Clean Water Act Section 316(b) Phase II Study	(15,310)	29,792	46,229	33,330	2,134	4,221	14,204
p.	Arsenic Groundwater Standard Program	0	0	155	0	27,840	0	0
q.	Big Bend 3 SCR	0	0	0	0	0	0	137,358
r	Big Bend 4 SCR	73,080	41,212	105,026	134,633	133,165	93,901	137,374
2.	Total of O&M Activities	985,351	997,464	(149,026)	872,411	65,793	1,029,625	(80,855)
3.	Recoverable Costs Allocated to Energy	946,161	967,672	(220,605)	826,719	24,822	1,021,954	(95,059)
4.	Recoverable Costs Allocated to Demand	19,190	29,792	71,579	45,692	40,971	7,671	14,204
5.	Retail Energy Jurisdictional Factor	0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142
6.	Retail Demand Jurisdictional Factor	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743
7.	Jurisdictional Energy Recoverable Costs (A)	915,721	923,809	(211,450)	784,170	23,613	989,808	(91,515)
8.	Jurisdictional Demand Recoverable Costs (B)	18,550	28,799	69,194	44,169	39,606	7,415	13,731
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$934,271	$952,608	($142,256)	$828,339	$63,219	$997,223	($77,784)

Line	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total	Method of Classification Demand	Method of Classification Energy
a.	$315,747	$284,635	$316,972	$274,971	$196,615	$3,342,509		$3,342,509
b.						0		0
c.	5,070	(3,177,141)	5,750	(5,194,241)	5,919	(11,656,193)		(11,656,193)
d.	559,910	584,009	909,929	998,774	1,299,016	7,542,688		7,542,688
e.	21,448	24,230	25,177	14,518	28,875	312,943		312,943
f.	0	1,603	575	0	0	475,890		475,890
g.	0	0	0	0	0	34,500	34,500	
h.	0	10,277	0	17,575	6,479	86,335	86,335	
i.	3,776	3,026	4,451	3,889	2,588	38,246		38,246
j.	11,420	11,711	16,673	0	32,377	146,098		146,098
k.	0	0	0	0	24,282	24,282		24,282
l.	0	0	0	0	0	0		0
m.	0	0	0	0	763	6,951		6,951
n.	0	0	0	0	0	2		2
o.	11,799	6,909	0	14,000	595	149,902	149,902	
p.	15,204	0	2,424	12,522	14,511	72,856	72,856	
q.	182,628	50,971	257,788	183,506	87,413	899,642		899,642
r	94,010	239,774	102,944	93,794	62,091	1,301,024		1,301,024
2.	1,221,012	(1,957,995)	1,642,863	(3,580,692)	1,751,523	2,777,475	$343,393	$2,434,081
3.	1,194,009	(1,977,181)	1,640,439	(3,624,788)	1,729,938	2,434,082		
4.	27,003	19,186	2,424	44,096	21,585	343,393		
5.	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701			
6.	0.9666743	0.9666743	0.9666743	0.9666743	0.9666743			
7.	1,145,387	(1,901,634)	1,588,061	(3,518,458)	1,693,385	2,340,897		
8.	26,103	18,547	2,343	42,626	20,866	331,949		
9.	$1,171,490	($1,883,087)	$1,590,404	($3,475,832)	$1,714,251	$2,672,846		

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

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090007 Hearing Exhibit - 00002935

EXHIBIT 2

Form 42-7A

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2008 to December 2008

Capital Investment Projects-Recoverable Costs

(in Dollars)

Line		Description (A)	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 Total	Method of Classification Demand	Method of Classification Energy
1.	a.	Big Bend Unit 3 Flue Gas Desulfurization 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	$806,109		$806,109
	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	750,451	748,492	746,532	744,573	742,637	741,193	741,160	740,684	738,819	737,109	738,520	746,237	8,916,407		8,916,407
	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	66,231	66,150	66,069	66,004	65,954	65,903	65,939	66,458	67,136	67,342	67,202	67,057	797,443		797,443
	n.	Big Bend PM Minimization and Monitoring	90,591	90,396	90,199	90,004	89,807	89,612	89,415	89,220	89,075	89,082	89,109	89,161	1,075,671		1,075,671
	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	23,579	23,539	23,499	23,451	23,401	23,357	23,313	23,269	23,225	23,181	23,137	23,093	280,044		280,044
	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	22,793	25,253	25,916	29,315	32,464	32,031	31,975	32,386	32,337	32,282	32,226	32,168	381,148		381,148
	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	815,255	923,533	922,724	921,641	920,542	920,130	5,423,825		5,423,825
	w.	Big Bend Unit 4 SCR	707,557	706,732	705,859	705,392	702,934	700,469	699,413	698,254	697,070	695,882	694,694	693,507	8,407,763		8,407,763
	x.	Big Bend FGD System Reliability	110,065	114,980	117,654	125,303	132,098	132,395	132,498	132,528	132,470	132,351	132,117	131,886	1,526,247		1,526,247
	y.	Clean Air Mercury Rule	1,934	3,617	5,799	6,334	6,383	6,412	6,434	6,486	6,537	6,607	6,733	6,353	71,609		71,609
	z.	SO_2 Emissions Allowances (B)	(648)	(616)	(603)	(590)	(577)	(564)	(550)	(534)	(494)	(453)	(445)	(439)	(6,513)		(6,513)
2.		Total Investment Projects - Recoverable Costs	2,205,269	2,210,332	2,211,695	2,219,721	2,224,108	2,218,890	3,032,005	3,138,486	3,134,195	3,129,398	3,127,277	3,133,674	31,985,040	$ 163,872	$ 31,821,168
3.		Recoverable Costs Allocated to Energy	2,191,441	2,196,536	2,197,921	2,205,986	2,210,406	2,205,218	3,018,364	3,124,877	3,120,618	3,115,850	3,113,762	3,120,189	31,821,168		
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	0.9678275	0.9545721	0.9585015	0.9485322	0.9513096	0.9685443	0.9627142	0.9592781	0.9617004	0.9680708	0.9706058	0.9788701			
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)	2,120,937	2,096,972	2,106,711	2,092,449	2,102,781	2,135,851	2,905,822	2,997,626	3,001,380	3,016,363	3,022,422	3,054,260	30,653,574		
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)	$2,134,304	$2,110,308	$2,120,016	$2,105,726	$2,116,026	$2,149,067	$2,919,008	$3,010,781	$3,014,505	$3,029,460	$3,035,487	$3,067,296	$30,811,984		

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

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Depreciation Memo Entry	447,762.85	441,807.43	443,818.89	447,834.98	457,709.40	463,754.34	542,853.53	620,752.53	622,671.14	628,577.49	628,631.89	634,121.72	6,380,424
ROI TOTAL	1,686,311	1,668,501	1,676,387	1,657,891	1,656,317	1,683,313	2,376,155	2,390,028	2,391,834	2,402,563	2,406,856	2,433,174	24,431,560

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EXHIBIT 3

42

Gulf's Responses to Staff's First Set of Interrogatories (Nos. 1-7)

DOCUMENTS REQUESTED

1. Please use the following table to provide information regarding Gulf's generating facilities and its air emission monitoring and control measures. Please use the keys to fill column (4), (7), (9), (12), and (14), and provide the definition of each key. E.g., B=base load, I=intermediate load, LNB=low NOx burner, SCR=selective catalytic reduction, etc.

RESPONSE:

Response included on pages 2 and 3.

Gulf's Generating Facilities and their Emission Monitoring & Controls Measures

As of April 2009

(1) Plant Name	(2) Unit No.	(3) Unit Type	(4) Operating Mode	(5) Net Summer Capacity	(6) Commercial In-Service Month/Year	(7) SO_2, NO_x, Hg, CO_2 and Particulate Monitoring: Existing Equipment / Technology	(8) In Operation (Yes/No)	(9) Equipment / Technology Under Construction	(10) In Service Date	(11) ECRC Project No.	(12) SO_2, NO_x, Hg, CO_2 and Particulate Controlling: Existing System/ Technology	(13) In Operation (Yes/No)	(14) System / Technology Under Construction	(15) In Service Date	(16) ECRC Project No.
						CEMS - SO2, NOx & CO2	Y		12/2002	1154	Precipitator	Y		1/1976	
						CEMS - Flow	Y		1/1993	1289	Precipitator Upgrade	Y		3/2008	1175
						CEMS - Opacity	Y		12/2002	1154	Sodium Injection	Y		12/2005	1214
											SNCR	Y		4/2006	1287
Crist	4	Coal	FS	78	7/1959			SO2, CO2, NOx and Flow to be combined in Common Stack when FGD is operational					FGD	2009	1222
						CEMS - SO2, NOx & CO2	Y		12/2002	1154	Precipitator	Y		1/1976	
						CEMS - Flow	Y		1/1993	1290	Precipitator Upgrade	Y		3/2008	1191
						CEMS - Opacity	Y		12/2002	1154	Sodium Injection	Y		12/2005	1214
											SNCR	Y		4/2006	1287
Crist	5	Coal	FS	78	6/1961			SO2, CO2, NOx and Flow to be combined in Common Stack when FGD is operational					FGD	2009	1222
						CEMS - SO2, NOx & CO2	Y		12/2002	1154	Precipitator	Y		1/1994	1243
						CEMS - Flow	Y		6/1/2005	1217	LNB / OFA	Y		11/2005	1287
						CEMS - Opacity	Y		2/2009	1283	SNCR	Y		11/2005	1287
Crist	6	Coal	FS	302	5/1970			SO2, CO2, NOx and Flow to be combined in Common Stack when FGD is operational					FGD	2009	1222
						CEMS - SO2, NOx & CO2	Y		12/2002	1154	Precipitator	Y		4/2004	1199
						CEMS - Flow	Y		7/1/2005	1217	LNB	Y		5/2004	1234
						CEMS - Opacity	Y		12/2002, 10/2004	1154, 1217	SCR	Y		4/2005	1199
Crist	7	Coal	FS	477	8/1973			SO2, CO2, NOx and Flow to be combined in Common Stack when FGD is operational					FGD	2009	1222
						CEMS - SO2, NOx & CO2	Y		7/02, 1/2002	1454,1441	Precipitator	Y		1/1977	
						CEMS - SO2, NOx & CO2 (Common Stack)	Y		12/2008	1444	Precipitator Upgrade	Y		5/07	1461
						CEMS - Flow (Common Stack)	Y		12/2008	1444	Sodium Injection	Y		1999	1413
Smith	1	Coal	FS	162	6/1965	CEMS - Opacity	Y		12/2008	1444			SNCR	2009	1488, 1469

Notes and Keys:

(4) FS = Fossil Steam (Base Load), CC = Combined Cycle (Intermediate Load), CT=Combustion Turbine (Peaking)

(7) CEMS - Continuous Emission monitoring System, PEMS - Parametric Emission Monitoring System

(12)(14) DLN= Dry Low NOx Combustors, FGD=Flue Gas Desulfurization, LNB=Low NOx Burners, OFA=Overfire Air, SCR=Selective Catalytic Reduction, SNCR= Selective Non-Catalytic Reduction

Gulf's Generating Facilities and their Emission Monitoring & Controls Measures
As of April 2009

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
						SO_2, NO_x, Hg, CO_2 and Particulate Monitoring					SO_2, NO_x, Hg, CO_2 and Particulate Controlling				
Plant Name	Unit No.	Unit Type	Operating Mode	Net Summer Capacity	Commercial In-Service Month/Year	Existing Equipment / Technology	In Operation (Yes/No)	Equipment / Technology Under Construction	In Service Date	ECRC Project No.	Existing System/ Technology	In Operation (Yes/No)	System / Technology Under Construction	In Service Date	ECRC Project No.
						CEMS - SO2, NOx & CO2	Y		7/20002, 12/2002	1454,1442	Precipitator	Y		1/1976	
						CEMS - SO2, NOx & CO2 (Common Stack)	Y		12/2008	1444	Precipitator Upgrade	Y		4/2005	1462
						CEMS - Flow (Common Stack)	Y		12/2008	1444	Sodium Injection	Y		11/1999	1413
Smith	2	Coal	FS	195	6/1967	CEMS - Opacity	Y		12/2008	1444	SNCR	Y		12/2008	1469
						CEMS - SO2, NOx & CO2	Y		1/2002	1311, 1316	Precipitator	Y		1/1974	
						CEMS - SO2, NOx & CO2 (Common Stack)	Y		7/2008	1357	Precipitator Controls	Y		11/2003	1330
						CEMS - Flow (Common Stack)	Y		12/2005	1324					
						CEMS - Opacity	Y		7/2008	1357					
Scholz	1	Coal	FS	46	3/1953	CEMS - Hg (Common Stack)	Y		8/2008	1362					
						CEMS - SO2, NOx & CO2	Y		1/2002	1311, 1316	Precipitator	Y		1/1974	
						CEMS - SO2, NOx & CO2 (Common Stack)	Y		7/2008	1357	Precipitator Controls	Y		11/2003	1330
						CEMS - Flow (Common Stack)	Y		12/2005	1324	Precipitator Upgrade	Y		12/2007	1305
						CEMS - Opacity	Y		7/2008	1357					
Scholz	2	Coal	FS	46	10/1953	CEMS - Hg (Common Stack)	Y		8/2008	1362					
						CEMS - SO2, NOx & CO2	Y		11/2004	1570	Precipitator	Y		12/1977	
						CEMS - Flow	Y		10/2007	1829					
						CEMS - Opacity	Y		12/2002						
Daniel	1	Coal	FS	260	9/1977										
						CEMS - SO2, NOx & CO2	Y		11/2004	1570	Precipitator	Y		12/1981	
						CEMS - Flow	Y		10/2007	1830	LNB / OFA	Y		12/2008	1826
Daniel	2	Coal	FS	253	6/1981	CEMS - Opacity	Y		12/2002						
Smith	3	Natural Gas	CC	556	4/2002	CEMS - NOx & CO2	Y		4/2002		DLN	Y		4/2002	
Smith	A	Oil	CT	32	5/1971	PEMS - NOx	Y		12/07	1684	None				

Notes and Keys:

(4) FS = Fossil Steam (Base Load), CC = Combined Cycle (Intermediate Load), CT=Combustion Turbine (Peaking)

(7) CEMS - Continuous Emission monitoring System, PEMS - Parametric Emission Monitoring System

(12)(14) DLN= Dry Low NOx Combustors, FGD=Flue Gas Desulfurization, LNB=Low NOx Burners, OFA=Overfire Air, SCR=Selective Catalytic Reduction, SNCR= Selective Non-Catalytic Reduction

2. Please fill out the following table to provide general information regarding each ash pond used for each of Gulf's coal generation units.

RESPONSE:

Plant Name /Unit No.	Crist	Smith	Scholz	Daniel
Ash pond used	1	1	1	1
Capacity of the pond***	272,703 cy	934,626 cy	141,990 cy	406,000 cy
Location of the pond	Southeast corner plant	Southeast of plant	West side of plant	North of plant
Date of the last inspection	January 2009	February 2009	February 2009	March 2008
Inspection findings**	Normal maintenance	Normal maintenance**	Normal maintenance**	Normal maintenance
Remedies implemented to address the findings	None	None	None	None
Scheduled date for the next inspection	4th Quarter 2009	4th Quarter 2009	4th Quarter 2009	March 2010
Safety control measures employed/ to be implemented	Regularly scheduled inspections	Regularly scheduled inspections	Regularly scheduled inspections	Regularly scheduled inspections
Related ECRC project	Yes	No	No	Yes
Associated costs recovered (and year) through the ECRC	1999: $76,683 2009: $800,000*	N/A	N/A	Dec.1993 (Project to Date): $10,027,215 1994: $3,338,941 1995: ($123,687) 2004: $291,412 2005: $34,130 2006: $2,610,315 2007: $15,469 2008: $10,458

*** Capacity is the remaining capacity of the pond.
** Inspection findings for Plants Smith and Scholz are based on FDEP exit interviews. Gulf Power has not received the final FDEP inspection reports.
* Projected 2009 ECRC expenses

3. Please explain what Federal/State/Municipal rules, regulations or permits govern Gulf's management of the safety of its ash ponds.

RESPONSE:

Management of Gulf ash ponds are regulated by conditions in each facility's Florida Department of Environmental Protection NPDES permit. Safety of the ash ponds is regulated by requirements to periodically survey dikes and toe areas for structural integrity and certify that no breaches or structural defects resulting in the discharge to surface water have occurred. Safety of the ash ponds is also regulated by requirements to certify that each ash pond provides the necessary minimum wet weather detention volume to contain the combined volume for all direct rainfall and all rainfall runoff to the pond from a 10-year, 24-hour rainfall event and the normal 24 hour dry weather flows. The certification for structural integrity and 24 hour retention volume, as described above, are required to be submitted annually.

4. Please fill out the following table to provide general information regarding each gypsum pond used for each of Gulf's coal generation units.

RESPONSE:

N/A

5. Please explain what Federal/State/Municipal rules, regulations or permits govern Gulf's management of the safety of its gypsum ponds.

RESPONSE:

N/A

6. Please fill out the following table to provide general information regarding each landfill used for each of Gulf's generation units.

RESPONSE:

The landfills at the Gulf Power plants are for coal combustion by-products.

Plant Name /Unit No.	Crist	Smith	Daniel	Daniel	Daniel
Landfill used	1	1	1 Closed	1 being capped and closed	1
Size of the landfill	78 acres	72 acres	55 acres	22 acres	30 acres
Location of the landfill	Southwest corner of property	East side of property	North side of Plant	North of Plant	North of Plant
Date of the last inspection	January 2009	February 2009*	March 2008	March 2008	March 2008
Inspection findings	Continue routine maintenance and inspections	Continue routine maintenance and inspections	Continue routine maintenance and inspections	Continue routine maintenance and inspections	Continue routine maintenance and inspections
Remedies implemented to address the findings	None	None	None	None	None
Scheduled date for the next inspection	4th Quarter 2009	4th Quarter 2009	March 2010	March 2010	March 2010
Safety control measures employed/ to be implemented	Regularly scheduled inspection	Regularly scheduled inspection	Regularly scheduled inspection	Regularly scheduled inspection	Regularly scheduled inspection
Related ECRC project	N/A	N/A	Yes	Yes	Yes
Associated costs recovered (and year) through the ECRC	N/A	N/A	See Response to Item No. 2		

* Inspection findings for Plants Smith are based on FDEP exit interviews. Gulf Power has not received the final FDEP inspection report.

7. Please explain what Federal/State/Municipal rules, regulations or permits govern Gulf's management of the safety of its landfills.

RESPONSE:

N/A

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Gulf's Responses to Staff's Second Set of Interrogatories (No. 8)

1. Referring to the testimony of Richard W. Dodd dated April 1, 2009, please provide a schedule that shows the capital structure, components, and cost rates relied upon for calculating the revenue requirement rate of return. Please include in this schedule the derivation of debt and equity components used in the Return on Average Net Investment, lines 7 (a) and (b), on Exhibit RWD-1 (formerly Schedule 8A) attached to the testimony. Please cite all sources and include the rationale for using the particular capital structure and cost rates.

ANSWER:

In accordance with FPSC Order No. PSC-94-0044-FOF-EI, the rate of return used to develop the revenue requirements of ECRC investment is based on the capital structure and cost rates approved in Gulf's last rate case, Docket No. 010949-EI, FPSC Order No. PSC-02-0787-FOF-EI, dated June 10, 2002.

Gulf Power Company
Environmental Cost Recovery Clause
Calculation of Revenue Requirement Rate of Return

Line	Capital Component	(1) Jurisdictional Rate Base Test Year ($000's)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %	(5) Revenue Requirement Rate %	(6) Monthly Revenue Requirement Rate %
1	Bonds	423,185	35.2733	6.44	2.2716	2.2716	
2	Short-Term Debt	33,714	2.8101	4.61	0.1295	0.1295	
3	Preferred Stock	98,680	8.2252	4.93	0.4055	0.6602	
4	Common Stock	492,186	41.0247	12.00	4.9230	8.0147	
5	Customer Deposits	13,249	1.1043	5.98	0.0660	0.0660	
6	Deferred Taxes	122,133	10.1801				
7	Investment Tax Credit	16,584	1.3823	8.99	0.1243	0.1790	
8	Total	1,199,731	100.0000		7.9199	11.3210	0.9434
	ITC Component:						
9	Debt	423,185	41.7321	6.44	2.6875	0.0371	
10	Equity-Preferred	98,680	9.7313	4.93	0.4798	0.0108	
11	-Common	492,186	48.5366	12.00	5.8244	0.1311	
12		1,014,051	100.0000		8.9917	0.1790	
	Breakdown of Revenue Requirement Rate of Return between Debt and Equity:						
13	Total Debt Component (Lines 1, 2, 5, and 9)					2.5042	0.2087
14	Total Equity Component (Lines 3, 4, 10, and 11)					8.8168	0.7347
15	Total Revenue Requirement Rate of Return					11.3210	0.9434

Notes:
(1) Capital Structure Approved by FPSC on April 26, 2002 in Doc. 010949-EI
(2) Column (1) / Total Column (1)
(3) Cost Rates Approved by FPSC on April 26, 2002 in Doc. 010949-EI
(4) Column (2) x Column (3)
(5) For equity components: Column (4) / (1-.38575); 38.575% = effective income tax rate
For debt components: Column (4)
(6) Column (5) / 12

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Gulf's Responses to Staff's Third Set of Interrogatories (No. 9)

9. Please refer to Schedule 8A of Exhibit RWD-1 of witness Richard Dodd's direct testimony on ECRC Calculation of Final True-up Amount Jan 2008 through Dec 2008. For the investment projects No.3 Crist 7 Flue Gas Conditioning (page 3 of 31), No.4 Low Nox Burners (page 4 of 31), No.5 CEM (page 4 of 31), No.8 Crist Cooling Tower Cell (page 8 of 31) and No.15 Daniel Ash Management (page 15 of 31), please provide narrative descriptions on why the cost amounts reported on Line 3 Less: Accumulated Depreciation are all positive.

ANSWER:

For each of the projects listed in question 9, some or all of the assets associated with the project were retired before they had been fully depreciated. Because we retire the full amount of an asset when it is removed from service, the Accumulated Depreciation Reserve balance of a specific PE can be positive. This can occur when an asset is fully retired and the accumulated depreciation balance was less than the retired amount. This is accounted for when a new depreciation study is performed every 4 years.

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Gulf's Responses to Staff's Fourth Set of Interrogatories (Nos. 10-14)

10. Please refer to the Description section of the Plant Smith Reclaimed Water Project in Gulf's Preliminary List of New Projects filed on July 14, 2009. Please provide answers to the following questions.

(a) Please identify the FPSC Order in which Gulf's Plant Smith Water Conservation and Consumptive Program was approved.

(b) Please describe the scope of the Program identified in (a).

(c) What are the estimated total O&M costs and total capital costs associated with the Plant Smith Water Conservation and Consumptive Program?

(d) How much of the costs identified in (c) have been incurred?

(e) How much of the costs identified in (c) have been recovered through the ECRC?

(f) When were the costs identified in (e) recovered?

(g) Will Gulf be soliciting bids for the newly proposed Plant Smith Reclaimed Water Project? If so, when will an RFP be issued?

(h) When will the design of the Project begin?

(i) When will construction of the Project begin?

(j) When will the construction of the Project be completed?

ANSWER:

(a) The first phase of the Smith Water Conservation project, the Consumptive Use-Shield Water Substitution project, was originally approved in FPSC Order No. PSC-01-1788-PAA-EI. The second phase of the project, the Plant Smith closed loop chiller for the laboratory sampling system, was approved in FPSC Order No. PSC-04-1187-FOF-EI.

(b) The Plant Smith Shield Water Project consisted of adding a 7.5 HP centrifugal pump, piping, valves, and controls at Plant Smith to reclaim water from the ash pond. The reclaimed ash pond water replaced groundwater that was being used as shield water within the Plant Smith Units 1 and 2 boilers.

Installation of the Plant Smith closed loop chiller for the laboratory sampling system allowed Plant Smith to reduce groundwater consumption by eliminating the need to cool the samples using groundwater.

Gulf Power is currently investigating the feasibility of utilizing reclaimed water at Plant Smith in Bay County, FL. Gulf has begun initial discussions with potential reclaimed water suppliers in the Bay County area. The Plant Smith Reclaimed Water project may ultimately include the necessary engineering and infrastructure for Gulf Power to connect to local reclaimed water source(s).

(c) The estimated capital cost for the Plant Smith Reclaimed Water project ranges from $20 to $30 million. This estimate was based on the cost of a similar project, the Plant Crist Water Conservation Project. The estimated O&M costs have not yet been determined.

(d) Gulf has incurred $62,489 of costs for the Plant Smith Reclaimed Water project.

(e) None of the $62,489 costs incurred for the Plant Smith Reclaimed Water project have been recovered through the ECRC.

(f) See response to Item No. 10(e). The project expenses have been and will continue to be booked to a preliminary investigation account until Gulf decides whether or not it is able to move forward with the project.

(g) Gulf will solicit bids for construction of the Plant Smith Reclaimed Water project if the Company moves forward with the project. Gulf has not determined when the request for proposal would be issued.

(h) The design portion of the Plant Smith Reclaimed Water project will begin after the preliminary investigation and feasibility study is complete. Feasibility will be determined based on which domestic wastewater facilities agree to participate in the water use project and how the project will be permitted.

(i) Construction will begin after the items described in response to Item 10(h) have been adequately addressed.

(j) The construction schedule and completion date for this project are unknown at this time.

11. Please refer to Gulf's statement in the last paragraph of the Description that the Company has incurred approximately $62,000, and expects to incur approximately an additional $35,000 of preliminary investigation expenses to evaluate utilizing reclaimed water in Plant Smith Unit 3 cooling tower; and that the project expenses have been and will continue to be booked to a preliminary investigation account until Gulf decides whether or not it is able to move forward with "the project." (quotation added) Please provide answers to the following questions.

(a) Please confirm that both the $62,000 and $35,000 have been neither recovered nor included in any ECRC cost projection filed previously.

(b) When was the $62,000 in expenses incurred?

(c) Please specify the category (i.e., O&M or capital) of the $62,000 and $35,000.

(d) Will the Company be seeking ECRC treatment of the $62,000 and $35,000 preliminary investigation costs amounts?

(e) Please define the meaning of "the project."

(f) When does the Company expect to make the decision on whether it is able to move forward with the project?

(g) If Gulf finally decides not moving forward with the project, will the Company be seeking ECRC recovery of the preliminary investigation costs incurred?

(h) If the answer to (g) is affirmative, please explain why such costs are recoverable via the ECRC, or cite a precedent for this treatment.

ANSWER:

(a) None of the costs Gulf has incurred for the Plant Smith Reclaimed Water project have been recovered through ECRC or included in any ECRC cost projections filed prior to 2009. The project expenses have been and will continue to be booked to a preliminary investigation account until Gulf decides whether or not it is able to move forward with the project.

(b) Gulf Power has incurred approximately $62,000 of preliminary investigation expenses to evaluate utilizing reclaimed water in the existing Plant Smith Unit 3 cooling tower. A breakdown of when the expenses were incurred is provided below:

Fourth quarter 2008: $46,867
First quarter 2009: $15,622

(c) The Plant Smith Reclaimed Water project preliminary investigation costs referenced above have been and will continue to be booked to a preliminary investigation account until Gulf decides whether or not it is able to move forward with the project. If Gulf moves forward with the project, the costs will be booked to the capital project. If the project is ultimately canceled the costs will be expensed to an O&M account.

(d) Yes, Gulf will be seeking ECRC recovery of the Plant Smith Reclaimed Water project preliminary investigation costs. As explained in Gulf's 2010 Preliminary List of New Projects for Cost Recovery, this potential project clearly meets the requirements of Plant Smith's Consumptive Use Permit. In addition, on October 20, 2008 the Northwest Florida Water Management District issued a letter to Gulf Power stating that the proposed re-use project meets the requirements listed in Specific Condition nine of Plant Smith's consumptive use permit.

(e) The project refers to the preliminary project investigation, engineering feasibility, engineering design, permitting and construction of the proposed Plant Smith Reclaimed Water project.

(f) The Company anticipates that it will make a decision on whether or not it is able to move forward with the project during 2010.

(g) Yes

(h) These preliminary investigation costs should be recoverable through

ECRC because Plant Smith's Consumptive Use Permit requires the plant to develop a plan to continue and expand implementation of water conservation and efficiency measures. Plant Smith is investigating the feasibility of the Reclaimed Water project as part of the plant's plan to reduce the demand for groundwater and surface water at the facility. The Plant Smith Reclaimed Water project was included in Plant Smith's water conservation plan that was submitted to the Northwest Florida Water Management District on July 22, 2009.

12. In the Description of the Plant Smith Reclaimed Water Project, the Company indicates that it has carried out the preliminary investigation to evaluate utilizing reclaimed water in the existing Smith Unit 3 cooling tower. Please explain whether the Company also intends to include Smith Units 1 and Unit 2 in the proposed Reclaimed Water Project.

ANSWER:

Gulf will continue to look for ways to utilize reclaimed water for Smith Units 1 and 2. At this time Gulf has not identified any viable uses of reclaimed water for these two units.

13. Referring to the Plant Smith Reclaimed Water Project, please identify the components that comprise the estimated 2010 capital expenditures of $1.5 million ± 20%.

ANSWER:

The estimated 2010 capital expenditures include costs for engineering feasibility studies as well as design of the infrastructure required to re-use this beneficial water source.

14. Please refer to the Plant Crist Unit 6 Precipitator Project on Gulf's Preliminary List of New Projects filed on July 14, 2009. Please provide answers to the following questions.

    (a) Please identify the components that comprise the estimated 2010 capital expenditures of $1.2 million ± 20%.

    (b) Will Gulf be soliciting bids for the Precipitator Project? If so, when will an RFP be issued?

    (c) When will the preliminary engineering of the project begin?

    (d) When will the design of the project begin?

ANSWER:

(a) The estimated 2010 capital expenditures include costs for preliminary engineering and design.

(b) Yes, Gulf will solicit bids for the Plant Crist Unit 6 precipitator project. Gulf plans to issue a request for proposals in 2011.

(c) Preliminary engineering will begin in 2010.

(d) Project design will begin in 2010.

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Gulf's Responses to Staff's Fifth Set of Interrogatories (Nos. 15-26)

15. Referring to lines 6 through 10, please explain why the Company did not include the new MACT ICR Project in its Preliminary List of New Projects filed on July 14, 2009.

ANSWER:

On July 2, 2009, EPA proposed an Information Collection Request (ICR) intended to supply the data necessary to develop a Maximum Achievable Control Technology (MACT) Rule for hazardous air pollutant (HAP) emissions. Gulf Power was in the process of reviewing the proposed ICR when the Company's Preliminary List of New Projects was filed on July 14, 2009. Gulf Power in conjunction with Southern Company submitted comments on the proposed ICR to EPA on August 31, 2009.

16. Please provide a detailed description of the MACT ICR Project.

ANSWER:

The MACT ICR project is comprised of three parts. Part I and Part II involve completing a survey and supplying extensive information on characteristics of each coal unit; fuel shipments; fuel analyses; and historical stack test data. Part III requires selected coal-fired generating sites to conduct specific emission tests. The sites were systematically selected according to age, level of control, hazardous air pollutant (HAP) input in coal, etc. Testing on selected units will be for acid gases, dioxin/furan organic HAP, non-dioxin/furan organic HAP, and/or mercury (Hg) and non-mercury metallic HAP.

Survey and Information Request (Proposed ICR Parts I and II)

- Part I includes questions regarding permitted emissions limits, emissions guarantees from vendors, capital costs of controls, and operating costs of controls.
- Part II requests 12 months of fuel analysis information as well as stack test information. All stack test information for particulate matter, acid gases, metallic HAPs, carbon monoxide, or other organics collected since January 1, 2004 must be reported.

Emission Testing (Proposed ICR Part III)

- Plant Smith will be required to test for Dioxin/Furan.
- Plant Scholz will be required to test for acid gases.
- Plant Daniel will be required to test for acid gases and organics.
- Plant Crist will be required to test for Hg and other metals.

17. Please provide a summary of the Law/Regulation Requirements for this newly proposed MACT ICR Project.

ANSWER:

Pursuant to Section 112 of the Clean Air Act, EPA on July 2, 2009, proposed an Information Collection Request (ICR) intended to supply the data necessary to develop a Maximum Achievable Control Technology (MACT) Rule for hazardous air pollutant emissions.

The proposed ICR includes 1) a three month response time for completing a survey and supplying extensive information on characteristics of every coal unit; fuel shipments; fuel analyses; and historical stack test data, and 2) an additional three months to complete numerous stack emission tests, which will be required for all of Gulf Power's coal plants.

18. Referring to lines 23 through 25, please explain how the estimated $541,000 in O&M expense was derived and identify each of the component items that comprise this estimated O&M cost.

ANSWER:

The O&M expenses were derived from estimated company manpower requirements, estimated sampling and analytical costs, and preliminary discussions with emission testing contractors. These expenses reflect the Company's best estimate at this time. A summary of the estimated O&M expenses is provided below.

	Smith	Crist	Scholz	Daniel **
Approximate Days of Testing	6	7	3	7
*Proposed Emission Test**	D	(A),M	A	A, O
Estimated Contractor Cost	$103,000	$171,000	$55,000	$104,000
Estimated Coal Analysis Cost	$18,000	$21,000	$21,000	$7,000
Estimated Coal Sampling Labor Cost	$7,000	$8,000	$5,000	$4,000
Plant Setup Cost	$4,000	$7,000	$2,000	$4,000
Estimated Total Cost:	$132,000	$207,000	$83,000	$119,000
		Total Estimate for		**$541,000**

*Test: A- acid gases, D- dioxins/furans, O- organics, M- Hg and other metals

() indicate the test was not selected by EPA but based on selection criteria, will likely be selected in the final ICR.

** Expenses presented for Gulf represent Gulf's ownership portion

19. Please explain whether Gulf is presently recovering any costs associated with the MACT ICR Project through base rates or any other recovery mechanism.

ANSWER:

None of the costs for the MACT ICR project are currently being recovered through base rates or any other cost recovery mechanism.

20. When will the MACT ICR Project begin?

ANSWER:

The MACT ICR project is expected to begin in January 2010.

21. When will the MACT ICR Project be completed?

ANSWER:

The MACT ICR Project is expected to be completed by August, 2010.

22. Please identify who, the Company or contractor(s), will conduct the ICR required activities described on page 11, lines 19 through 21.

ANSWER:

The Company will conduct all of the ICR activities identified on page 11, lines 19 through 21.

23. Will the Company be soliciting bids for the contractor? If so, when will an RFP be issued?

ANSWER:

The Company will conduct all of the ICR activities identified on page 11, lines 19 through 21; therefore, no RFP will be issued for this work.

24. If the response to No. 23 is negative, has the Company retained the contractors to provide the services?

ANSWER:

See Gulf's response to Item No. 22.

25. If the response to No. 24 is affirmative, please identify each of the contractors that have been retained, as well as the services that each contractor will provide.

Answer:

N/A

26. Please refer to Gulf's response to Staff's 4th Set of Interrogatories No.10(c) filed on August 10, 2009. When will the Plant Reclaimed Water Project be completed?

ANSWER:

The construction schedule and a completion date will be identified after Gulf determines whether or not it is feasible to move forward with this project. The Company anticipates that it will make a decision on whether of not it is able to move forward with the project during 2010.

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Gulf's Responses to Staff's First Request for Production of Documents (Nos. 1-6)

1. Please provide a copy of the "Specific Condition Nine of the Northwest Florida Water Management District (NFWMD) Individual Water Use Permit (No. 19850073) issued November 30, 2006," that Gulf described in its Preliminary List of New Projects.

RESPONSE:

A copy of the Northwest Florida Water Management District Individual Water Use Permit No. 19850073, containing Specific Condition Nine, is included as Attachment A.

Attachment A

Northwest Florida Water Management District

152 Water Management Drive, Havana, Florida 32333-4712

(850) 539-5999 (Fax) 539-2777

Douglas E. Barr
Executive Director

December 4, 2006

Gulf Power, Inc.
Lansing Smith Electric Generating Plant
One Energy Place
Pensacola, FL 32520 0328

NOTICE OF AGENCY ACTION
Individual Water Use Permit No. 19850073
Consumptive Use Permit Application No. 106771

Dear Permitee:

Your Individual Water Use Permit was approved by the Governing Board of the Northwest Florida Water Management District at a public hearing on November 30, 2006. The permit issued is subject to the terms and conditions set forth in the enclosed permit document. As you are legally responsible for compliance with the conditions of the permit please read the document thoroughly. Pay close attention to any condition(s) of the permit which require the one-time or periodic submittal of information to the District. Non-compliance may require the District to initiate enforcement action, including the possible assessment of administrative fines. Please designate an individual as the contact person for compliance. This can be done by sending the person's name, address, phone number and email address in hard-copy to the above address or via email (compliance@nwfwmd.state.fl.us).

If the property where the withdrawal facility is located changes ownership, the permit must be transferred. A permit transfer request must be made on NWFWMD Form A2-F (http://www.nwfwmd.state.fl.us/permits/forms/permit_transfer.pdf) and approved by the Executive Director. If the permit is not transferred you may remain responsible for compliance with the conditions of the permit.

If you have any questions concerning the permit document or if the District can be of any other service, please let us know.

Sincerely,

Angela Chelette, Chief
Bureau of Ground Water Regulation
Division of Resource Regulation

Enclosure
cc: Richard M. Markey

NORTHWEST FLORIDA WATER MANAGEMENT DISTRICT
INDIVIDUAL WATER USE PERMIT

(NWFWMD Form No. 42-E)

Permit granted to:	Permit No.: 19850073 Renewal/Modification
Gulf Power Company Lansing Smith Electric Generating Plant One Energy Place Pensacola, Florida 32520-0328 (Legal Name and Address)	Date Permit Granted: November 30, 2006 Permit Expires On: December 1, 2011 Source Classification: Floridan Aquifer, North Bay, Recycled Water Use Classification: Power Generation, Public Supply, Industrial Uses
County: Bay Area: B	Location: Section ____ 1/4 Section ____
Application No.: 106771	Township 2 South Range 14, 15 West

Terms and standard conditions of this Permit are as follows:

1. That all statements in the application and in supporting data are true and accurate and based upon the best information available, and that all conditions set forth herein will be complied with. If any of the statements in the application and in the supporting data are found to be untrue and inaccurate, or if the Permittee fails to comply with all of the conditions set forth herein, then this Permit shall be revoked as provided by Chapter 373.243, Florida Statutes.

2. This Permit is predicated upon the assertion by the Permittee that the use of water applied for and granted is and continues to be a reasonable and beneficial use as defined in Section 373.019(4), Florida Statutes, is and continues to be consistent with the public interest, and will not interfere with any legal use of water existing on the date this Permit is granted.

3. This Permit is conditioned on the Permittee having obtained or obtaining all other necessary permit(s) to construct, operate and certify withdrawal facilities and the operation of water system.

4. This Permit is issued to the Permittee contingent upon continued ownership, lease or other present control of property rights in underlying, overlying, or adjacent lands. This Permit may be assigned to a subsequent owner as provided by Chapter 40A-2.351, Florida Administrative Code, and the acceptance by the transferee of all terms and conditions of the Permit.

5. This Permit authorizes the Permittee to make a combined average annual withdrawal of **275,200,000*** gallons of water per day, a maximum combined withdrawal of **276,160,000**** gallons during a single day, and a combined monthly withdrawal of **8,531,200,000***** gallons. Withdrawals for the individual facilities are authorized as shown in the table below in paragraph six. However, the total combined amount of water withdrawn by all facilities listed in paragraph six shall not exceed the amounts identified above.

6. Individual Withdrawal Facility Authorization

WITHDRAWAL POINT ID NO.	LOCATION SEC,TWN,RNG	GALLONS/DAY AVERAGE	GALLONS/DAY MAXIMUM
LSGP #1 (AAA6592)	Sec 36, T2S, R15W		720,000
LSGP #2 (AAA6591)	Sec 36, T2S, R15W		720,000
LSGP #3 (AAA6590)	Sec 36, T2S, R15W		Abandoned
LSGP #4 (AAD3491)	Sec 25, T2S, R15W		720,000
LSGP #5 (AAE0186)	Sec 19, T2S, R15W		720,000
LSGP #6 (To Be Assigned)	Sec. 17, T2S, R14W		720,000 Proposed
LGSP 1A/NB	Sec. 36, T2S, R15W		68,256,000
LGSP 1B/NB	Sec 36, T2S, R15W		68,256,000
LGSP 2A/NB	Sec 36, T2S, R15W		68,256,000
LGSP 2B/NB	Sec 36, T2S, R15W		68,256,000

* 1,200,000 Ground Water – 274,000,000 Surface Water
** 2,160,000 Ground Water – 274,000,000 Surface Water
*** 37,200,000 Ground Water – 8,494,000,000 Surface Water

7. The use of the permitted water withdrawal is restricted to the use classification set forth by the Permit. Any change in the use of said water shall require a modification of this Permit.

8. The District's staff, upon proper identification, will have permission to enter, inspect and observe permitted and related facilities in order to determine compliance with the approved plans, specifications and conditions of this Permit.

9. The District's staff, upon providing prior notice and proper identification, may request permission to collect water samples for analysis, measure static and/or pumping water levels and collect any other information deemed necessary to protect the water resources of the area.

10. The District reserves the right, at a future date, to require the Permittee to submit pumpage records for any or all withdrawal point(s) covered by this Permit.

11. Permittee shall mitigate any significant adverse impact caused by withdrawals permitted herein on the resource and legal water withdrawals and uses, and on adjacent land use, which existed at the time of permit application. The District reserves the right to curtail permitted withdrawal rates if the withdrawal causes significant adverse impact on the resource and legal uses of water, or adjacent land use, which existed at the time of permit application.

12. Permittee shall not cause significant saline water intrusion or increased chloride levels. The District reserves the right to curtail permitted withdrawal rates if withdrawals cause significant saline water intrusion or increased chloride levels.

13. The District, pursuant to Section 373.042, Florida Statutes, at a future date, may establish minimum and/or management water levels in the aquifer, aquifers, or surface water hydrologically associated with the permitted withdrawals; these water levels may require the Permittee to limit withdrawal from these water sources at times when water levels are below established levels.

14. Nothing in this Permit should be construed to limit the authority of the Northwest Florida Water Management District to declare water shortages and issue orders pursuant to Section 373.175, Florida Statutes, or to formulate and implement a plan during periods of water shortage pursuant to Section 373.246, Florida Statutes, or to declare Water Resource Caution Areas pursuant to Chapters 40A-2.801, and 62-40.41, Florida Administrative Code

    (a) In the event of a declared water shortage, water withdrawal reductions shall be made as ordered by the District.

    (b) In the event of a declared water shortage or an area as a Water Resource Caution Area, the District may alter, modify or inactivate all or parts of this permit.

15. The Permittee shall properly plug and abandon any well determined unsuitable for its intended use, not properly operated and maintained, or removed from service. The well(s) shall be plugged and abandoned to District Standards in accordance with Section 40A-3.531, Florida Administrative Code.

16. Any Specific Permit Condition(s) enumerated in Attachment A are herein made a part of this Permit.

Authorized Signature
Northwest Florida Water Management District

ATTACHMENT
Gulf Power Company
Lansing Smith Electric Generating Plant

Individual Water Use Permit No. 19850073
Individual Water Use Application No. 106771

1. The Permittee shall include the Individual Water Use Permit number and the well's Florida Unique Identification Number when submitting reports or otherwise corresponding with the District.

2. The Permittee shall not exceed ground water withdrawal amounts of an annual average daily amount of 1.2 million gallons, a maximum daily amount of 2.16 million gallons, and a maximum monthly amount of 37.2 million gallons.

3. The Permittee shall not exceed surface water withdrawal amounts of an annual average daily amount of 274 million gallons, a maximum daily amount of 274 million gallons and a maximum monthly amount of 8,494 million gallons.

4. The Permittee shall record the data required on the Water Use Summary Reporting Form, NWFWMD A2-I, and submit copies to the District by January 31 of each year. The withdrawals shall be reported separately by source (ground water, surface, and reclaimed). The ground and surface water withdrawals shall also be provided as an aggregate. The Permittee, if preferred, may submit the report electronically by downloading the correct form from the District website, filling it out properly, and e-mailing it to compliance@nwfwmd.state.fl.us. The next report is due January 31, 2007.

5. The Permittee, by January 31, April 30, July 31, and October 31 of each year, shall report the following information as specified below:

   a. Water quality results from tests conducted on each production well of the system during the first two weeks of the months of January, April, July, and October as appropriate to the reporting period. The water quality analysis shall test for the following chemical concentrations: chloride, sodium, sulfate, bicarbonate, carbonate, calcium, magnesium, potassium, and total dissolved solids. Prior to sampling, the Permittee shall purge approximately three to five well volumes from each well, and shall report with each set of test results, the duration of purging, purge volume, and purge rates used.

   b. Static water level data for each production well as recorded during the first two weeks of January, April, July, and October as appropriate to the reporting period. The water level data shall be referenced to mean sea level.

   The next water use, water quality and water level reports are due by January 31, 2007.

6. The Permittee shall continue to return approximately 95 percent or more of the surface water withdrawn.

7. The Permittee, at the time of construction, shall install an in-line totaling flow meter at the well head of proposed well LSGP #6. The Permittee shall maintain in working order in-line totaling flow meters on all other ground water wells.

8. The Permittee shall not exceed a withdrawal rate of 2,000 gallons per minute from the Floridan aquifer. The Permittee, at the time that LSGP #6 is operational, shall implement the pumping scenario identified in the ground water modeling analysis whereby LSGP #4, LSGP #5, and LSGP #6 are operated as primary wells and LSGP #1 and #2 are operated as backup and emergency supply wells.

9. The Permittee shall develop a plan to continue and expand implementation of water conservation and efficiency measures at the plant. The findings of the plan, along with a timetable for implementation, shall be submitted to the District no later than July 31, 2009.

10. The Permittee shall mitigate impacts attributable to the authorized withdrawal that interfere with users of water in the vicinity of Gulf Power's wells. The Permittee shall report the occurrence of any such impacts to the District and shall identify the mitigation action undertaken to address the impacts.

Attachment B

Northwest Florida Water Management District

152 Water Management Drive, Havana, Florida 32333-4712
U.S. Highway 90 10 miles west of Tallahassee

(850) 539-5999 • (Fax) 539-2777

Douglas E. Barr
Executive Director

October 20, 2008

Mr. Mike Markey
Gulf Power Company
One Energy Place
Pensacola, Florida 32520-0328

RE: Individual Water Use Permit No. 19850073
Specific Condition No. 9

Dear Mr. Markey:

The District understands that Gulf Power is working to obtain reuse water as part of Gulf Power's water conservation effort in accordance with Specific Condition No. 9 of the Individual Water Use Permit. Obtaining and utilizing reuse water to directly reduce demand for ground water and surface water would result in a significant benefit to the water resources of the area. This activity clearly meets the intent of the permit condition. If I can provide any other information or endorsement in support of this effort, please contact me.

Sincerely,

Angela Chelette

Angela Chelette, P.G.
Chief, Bureau of Ground Water Regulation

3. Referring to the Plant Smith Reclaimed Water Project, please provide all documents and work papers that support the estimated 2010 capital expenditures of $1.5 million ± 20%.

RESPONSE:

The 2010 cost estimate was generated from past engineering experience on a similar project conducted at Plant Crist. In addition, a conference call with an infrastructure engineering firm was conducted to obtain some general design information.

4. Please provide the Company's scope, budget and schedule for the Plant Smith Reclaimed Water Project.

RESPONSE:

The final scope of this project has not been developed at this time. The estimated budget is approximately $20-30 million. The schedule will be determined after feasibility studies have been completed and commitments from domestic wastewater treatment facilities have been received. Local wastewater treatment facilities will supply the needed reclaimed water for this project.

5. Referring to the Plant Crist Unit 6 Precipitator Project, please provide all documents and work papers that support the estimated 2010 capital expenditures of $1.2 million ± 20%.

RESPONSE:

The 2010 budget projection for the Plant Crist Unit 6 precipitator project was based on preliminary engineering and design cost for the Plant Crist Units 4 and 5 precipitator upgrades which was adjusted for the different characteristics of Crist Unit 6.

6. Please provide the Company's scope, budget and schedule for the Plant Crist Unit 6 Precipitator Project.

RESPONSE:

Gulf will begin developing the detailed scope of work, budget, and schedule for the Plant Crist Unit 6 precipitator project during 2010. The scope of work will include replacing the precipitator internals by 2013.

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Gulf's Responses to Staff's Second Request for Production of Documents (No. 7)

7. Referring to the testimony of Richard W. Dodd date August 28, 2009, please provide a schedule that shows the capital structure, components, and cost rates relied upon for calculating the revenue requirement rate of return. Please include in this schedule the derivation of debt and equity components used in the Return on Average Net Investment, lines 7 (a) and (b), on Schedule 4P attached to the testimony. Please cite all sources and include the rationale for using the particular capital structure and cost rates.

ANSWER:

In accordance with FPSC Order No. PSC-94-0044-FOF-EI, the rate of return used to develop the revenue requirements of ECRC investment is based on the capital structure and cost rates approved in Gulf's last rate case, Docket No. 010949-EI, FPSC Order No. PSC-02-0787-FOF-EI, dated June 10, 2002.

Gulf Power Company
Environmental Cost Recovery Clause
Calculation of Revenue Requirement Rate of Return

Line	Capital Component	(1) Jurisdictional Rate Base Test Year ($000's)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %	(5) Revenue Requirement Rate %	(6) Monthly Revenue Requirement Rate %
1	Bonds	423,185	35.2733	6.44	2.2716	2.2716	
2	Short-Term Debt	33,714	2.8101	4.61	0.1295	0.1295	
3	Preferred Stock	98,680	8.2252	4.93	0.4055	0.6602	
4	Common Stock	492,186	41.0247	12.00	4.9230	8.0147	
5	Customer Deposits	13,249	1.1043	5.98	0.0660	0.0660	
6	Deferred Taxes	122,133	10.1801				
7	Investment Tax Credit	16,584	1.3823	8.99	0.1243	0.1790	
8	Total	1,199,731	100.0000		7.9199	11.3210	0.9434
	ITC Component:						
9	Debt	423,185	41.7321	6.44	2.6875	0.0371	
10	Equity-Preferred	98,680	9.7313	4.93	0.4798	0.0108	
11	-Common	492,186	48.5366	12.00	5.8244	0.1311	
12		1,014,051	100.0000		8.9917	0.1790	
	Breakdown of Revenue Requirement Rate of Return between Debt and Equity:						
13	Total Debt Component (Lines 1, 2, 5, and 9)					2.5042	0.2087
14	Total Equity Component (Lines 3, 4, 10, and 11)					8.8168	0.7347
15	Total Revenue Requirement Rate of Return					11.3210	0.9434

Notes:
(1) Capital Structure Approved by FPSC on April 26, 2002 in Doc. 010949-EI
(2) Column (1) / Total Column (1)
(3) Cost Rates Approved by FPSC on April 26, 2002 in Doc. 010949-EI
(4) Column (2) x Column (3)
(5) For equity components: Column (4) / (1-.38575); 38.575% = effective income tax rate
For debt components: Column (4)
(6) Column (5) / 12

7. Referring to the testimony of Richard W. Dodd date August 28, 2009, please provide a schedule that shows the capital structure, components, and cost rates relied upon for calculating the revenue requirement rate of return. Please include in this schedule the derivation of debt and equity components used in the Return on Average Net Investment, lines 7 (a) and (b), on Schedule 4P attached to the testimony. Please cite all sources and include the rationale for using the particular capital structure and cost rates.

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Gulf Power Company
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Gulf Power Company
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(4) Column (2) x Column (3)
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For debt components: Column (4)
(6) Column (5) / 12

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Gulf's Responses to Staff's Third Request for Production of Documents (No. 8)

8. Please provide the workpapers and any supporting documents that support Gulf's response to Interrogatory No. 18.

ANSWER:

See Attachment A.

attachment A

Keough, Ashley J.

From: Markham, Sarah

Sent: Monday, August 03, 2009 5:20 PM

To: Stewart, Jerry L.; Jones, Douglas E.; Flowers, Kimberly D.; McCullough, Theodore J.; Hobson, Chris M.; Huling, Charles H.; Just, Ronny D.; Mitchell, Aaron David; Bowden, Matthew W.; Marino, Anthony J.; Vick, James O.; Waters, G. Dwain; Terry, Greg N.; Berry, Charles Rick (MPC); Hedden, Patrick H.; Steele, C. Mark; McCullars, Jennifer W.

Cc: Monroe, Larry S.; Wilson, Cyndi; Kelley, Eric; Baldwin, Bryan; Adelberg, Kimberly Malm; Herrin, Danny (SCSB); Looney, M. Brandon; Blackburn, Jonathon David; Campbell, Margaret C. (TS)

Subject: O&M Cost Estimates: EPA's proposed Information Collection Request

All,
As you are aware, EPA recently proposed an extensive Information Collection Request (ICR) for coal- and oil-fired electric generating units to support a Maximum Achievable Control Technology (MACT) rulemaking. This ICR will be required and we will have to comply. The proposed ICR consists of 3 parts.

- Parts I and II will be a survey sent to all coal- and oil- fired electric generating units in the industry greater than 25 MW and will require submission of existing data (e.g., emissions data, current controls and costs, fuel analyses, etc.). We plan that Parts I and II will be completed by a cooperative effort between Research and Environmental Affairs, the operating company Environmental Affairs, Engineering and Construction Services, Fuel Services, and others as needed.
- Part III is a broad emission testing program that will be required for coal- and oil-fired units selected by EPA, which were generally selected because of their emissions or emission controls. This portion of the ICR will require significant external resources, and therefore significant costs. The table below highlights the units selected for testing and our best current estimated costs. It is important to note that the ICR is still in the proposal stage and may change by the time the final ICR is issued - the plants and the scope of work may change.

ICR Part III- Emission Testing Only 2010 Budget (100% view)	
Alabama Power	**Estimated Cost**
Barry 5	$157,000
Gadsden 1	$80,000
Gaston 3	$205,000
Gorgas 8,9,10	$79,000
Green Co. 1	$129,000
Miller 4	$372,000
Total:	**$1,022,000**
Georgia Power*	**Estimated Cost**
Bowen 3	$156,000
Hammond 1,2,3,4	$243,000
Kraft 3	$83,000
McIntosh 1	$84,000
McManus 1	$379,000
Mitchell 3**	$80,000
Scherer 3	$378,000
Wansley 2	$156,000
Yates 7	$81,000
Total:	**$1,640,000**
Gulf Power	**Estimated Cost**
Crist 4,5,6,7	$207,000
Scholz 1	$83,000
Smith 2	$132,000
Total:	**$422,000**
Mississippi Power	**Estimated Cost**
Daniel 2	$239,000

attachment A

Watson 5	$132,000
Total:	**$371,000**
Southern Co.	**$3,455,000**

*Plant Branch is not currently selected by EPA.
**Although we are in the process of converting Mitchell to biomass, it was included on EPA's list so we have included it also.

The costs in the table above represent only the external cost associated with Part III of the ICR, emission testing. These costs do not include the significant internal resources that will be relied upon to complete this ICR. We expect that the emissions testing effort will begin in early 2010 and will complete later that year, therefore the costs estimated in the table are for 2010 only. We are currently developing comments to submit to EPA and then to the White House Office of Management and Budget (OMB). Our goal is to reduce the costs and burden of this ICR. We estimate the following schedule:

Proposed ICR: July 2
Comments due to EPA: August 31
Comments due to OMB: Fall 2009
ICR issued: Early 2010
Parts I and II due: Spring 2010
Part III due: Mid-2010

We are working with Cyndi Wilson in Accounting to add these estimates to the 2010 O&M budgets. Also, if you would like us to assist in communicating the ICR to the affected plants, please let us know.

Sarah S. Markham
205.257.6780

Larry Monroe
205.257.7772

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Revised Schedule 5A, filed 4/1/09

Schedule 5A
Revised 4/14/09

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2008 - December 2008

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	0
	.2 Air Emission Fees	-	700,225	23	-	-	-	-	-	-	-	-	123,874	824,122	0	824,122
	.3 Title V	8,180	9,382	8,735	7,963	6,200	8,317	9,668	8,906	9,299	8,686	8,365	9,129	102,830	0	102,830
	.4 Asbestos Fees	1,500	-	300	(1,537)	(79)	-	-	-	-	300	-	(184)	300	300	0
	.5 Emission Monitoring	30,700	31,550	59,328	39,967	43,127	40,897	23,046	47,554	36,120	40,971	43,706	73,015	509,981	0	509,981
	.6 General Water Quality	9,714	25,580	12,045	15,198	28,455	47,583	40,869	39,012	77,796	46,332	42,477	23,438	408,499	408,499	0
	.7 Groundwater Contamination Investigation	(6,161)	64,126	84,006	62,604	122,829	561,836	179,514	33,258	253,815	59,367	41,162	37,743	1,494,099	1,494,099	0
	.8 State NPDES Administration	-	-	-	-	-	-	-	-	-	-	7,500	34,500	42,000	42,000	0
	.9 Lead and Copper Rule	3,583	-	3,036	-	547	3,382	-	3,974	300	6,068	-	-	20,890	20,890	0
	.10 Env Auditing/Assessment	-	-	3,909	377	414	-	10,302	2,808	21	-	215	801	18,847	18,847	0
	.11 General Solid & Hazardous Waste	19,751	15,681	55,590	30,230	36,632	35,756	71,588	33,756	16,933	38,192	17,134	56,805	428,048	428,048	0
	.12 Above Ground Storage Tanks	(7,688)	7,188	35,683	24,143	(7,078)	5,491	25,468	341	1,127	-	19,697	2,439	106,811	106,811	0
	.13 Low Nox	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.14 Ash Pond Diversion Curtains	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.15 Mercury Emissions	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.16 Sodium Injection	18,013	18,068	5,376	24,848	17,380	29,554	7,314	14,571	22,607	7,844	7,457	34,267	207,299	0	207,299
	.17 Gulf Coast Ozone Study	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.18 SPCC Substation Project	-	-	-	-	-	-	-	-	-	-	14,155	54,790	68,945	68,945	0
	.19 FDEP NOX Reduction Agreement	596,519	389,227	169,915	438,599	207,430	258,005	303,745	215,627	281,206	250,847	305,751	223,012	3,639,883	0	3,639,883
	.20 CAIR/CAMR/CAVR Compliance Program	-	-	-	169,999	55,534	(10,665)	19,182	20,261	197,080	21,529	19,557	90,929	583,406	0	583,406
	.21 Mercury Allowances	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.22 Annual NOx Allowances	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.23 Seasonal NOx Allowances	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.24 SO2 Allowances	563,792	510,454	499,179	509,587	449,566	590,490	668,732	624,613	545,756	361,070	359,941	364,330	6,047,510	0	6,047,510
2	Total of O & M Activities	1,237,903	1,771,481	937,125	1,321,978	960,957	1,570,646	1,359,428	1,044,681	1,442,060	841,206	887,112	1,128,888	14,503,470	2,588,439	11,915,031
3	Recoverable Costs Allocated to Energy	1,217,204	1,658,906	742,556	1,190,963	779,237	916,598	1,031,687	931,532	1,092,068	690,947	744,777	918,556	11,915,031		
4	Recoverable Costs Allocated to Demand	20,699	112,575	194,569	131,015	181,720	654,048	327,741	113,149	349,992	150,259	142,340	210,332	2,588,439		
5	Retail Energy Jurisdictional Factor	0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849			
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)	1,173,581	1,603,301	718,271	1,154,594	755,444	888,501	1,001,039	903,136	1,059,663	669,536	720,077	886,370	11,533,513		
8	Jurisdictional Demand Recoverable Costs (B)	19,958	108,546	187,607	126,327	175,217	630,644	316,013	109,100	337,468	144,882	137,247	202,805	2,495,814		
9	Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8)	1,193,539	1,711,847	905,878	1,280,921	930,661	1,519,145	1,317,052	1,012,236	1,397,131	814,418	857,124	1,089,175	14,029,327		

Notes:
(A) Line 3 x Line 5 x line loss multiplier
(B) Line 4 x Line 6

DOCUMENT NUMBER-DATE
03614 APR 20 8
FPSC-COMMISSION CLERK

090007 Hearing Exhibit - 00003002

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PSC's Audit Report for Gulf

State of Florida

FLORIDA PUBLIC SERVICE COMMISSION

DIVISION OF REGULATORY COMPLIANCE
BUREAU OF AUDITING

Tallahassee District Office

GULF POWER COMPANY

ENVIRONMENTAL COST RECOVERY CLAUSE AUDIT

TWELVE MONTH PERIOD ENDED DECEMBER 31, 2008

DOCKET NO. 090007-EI

AUDIT CONTROL NO. 09-012-1-1

Donna D. Brown

Donna Brown, Audit Manager

Lynn M. Deamer

Lynn M. Deamer, Audit Supervisor

TABLE OF CONTENTS

I.		PURPOSE	1
II.		OBJECTIVES AND PROCEDURES	2
III.		EXHIBITS	5
	1.	END OF PERIOD TRUE UP	5
	2.	INTEREST PROVISION	6

DIVISION OF REGULATORY COMPLIANCE

AUDITOR'S REPORT

June 05, 2009

TO: FLORIDA PUBLIC SERVICE COMMISSION

We have performed the procedures described later in this report to meet the agreed upon objectives set forth by the Division of Economic Regulation in its audit service request. We have applied these procedures to the attached schedules prepared by Gulf Power Company in support of its filing for Environmental Cost Recovery Clause (ECRC) True-Up for the 12-month period ending December 31, 2008, Docket No. 090007-EI.

This audit is performed following general standards and field work standards found in the AICPA Statements on Standards for Attestation Engagements. This report is based on agreed upon procedures which are only for internal Commission use.

OBJECTIVES AND PROCEDURES

REVENUES

Objective: To determine that the revenue filed by the company for each cost recovery clause is supported by company documentation and agrees to the general ledger. To verify that the appropriate clause factors are utilized by the company in billing the customers.

Procedures: ECRC revenues were audited jointly with the revenue portions of the other clause audits of Gulf Power Company. The work product is contained in Docket No. 090001-EI, ACN: 09-041-1-4.

EXPENSES

O & M Expenses

Objective: To verify that the company's ECRC Operation and Maintenance expenses for the year ended December 31, 2008 are representative of management's assertions displayed in the books and records.

Procedures: The audit staff recomputed the company's O&M expenses from the monthly general ledger and agreed it to the company's filing Schedule 5A. Verified adjustments to O&M expenses for costs recovered in base rates as per FPSC Order PSC-94-0044-FOF-EI, issued January 12, 1994. Compiled a sample of expenses and traced them to supporting vendor invoices.

SO2 Expenses

Objective: To verify that the company's ECRC SO2 expenses and revenues for the year ending December 31, 2008 are representative of its books and records.

Procedure: Obtained a schedule, by month, of the SO2 allowance expenses for 2008 including revenues, inventory, expensed amounts and the amount included in working capital. Recomputed and traced the emission allowances to Schedule 8A, page 31 of 31 of the company's filing and the general ledger.

Depreciation Expense

Objective: To verify the company's ECRC depreciation on Schedule 8A is correctly computed and omits dismantlement expense for the period ended December 31, 2008.

Procedures:
Obtained supporting company documents calculating depreciation and amortization amounts by month for 2008. Obtained a copy of the Depreciation and Dismantlement Study filed in Docket No. 050381-EI, FPSC Order PSC-06-0348-PAA-EI, issued May 19, 2006, and FPSC Order

PSC-07-0013-PAA-EI, issued January 2, 2007. Recalculated monthly depreciation expense excluding dismantlement expense, and agreed it to company filing for Plant Expenditure's (PE's) on Schedule 8A.

TRUE-UP

Objective: To determine if the true-up calculation and interest provision for the period ended December 31, 2008 as filed with this Commission was calculated correctly.

Procedures: Recalculated the company's total true-up and interest provision for the period ended December 31, 2008 and agreed it to the company filing Schedule 2A. Traced the beginning true-up amount to the 2006 ECRC audit and the true-up provision to FPSC Order PSC-06-0972-FOF-EI, issued November 22, 2006. Agreed rates used to calculate interest provision to the Wall Street Journal 30 day commercial paper rates.

INVESTMENT

Objective: To verify that the company's Capital Investment Projects for the year ended December 31, 2008 are representative of management's assertions displayed in the books and records. To verify that where an ECRC project involves the replacement of existing plant assets, the company is retiring the installed costs of replaced units according to Rule 25-6.0142(4)(b),F.A.C.

Procedures: Generated a schedule which recalculated the Capital Investment Projects recoverable through the ECRC and agreed it to the company filing Schedule 7A. Agreed the total jurisdictional recoverable costs of Capital Investment Projects to the recalculation of company's true-up. Recalculated the appropriate energy jurisdictional factors for each month and agreed all Capital Investment Projects, depreciation expense, accumulated depreciation, and plant in service balances to Schedule 8A.

OTHER

<u>Deferred Accounting</u>

Objective: To determine that the utility's Working Capital balance is properly calculated in compliance with Commission rules.

Procedures: Obtained source documentation of plant expenditures not included in the 2008 filing which were recorded in a deferred account. Obtained FPSC Order PSC-07-0721-S-EI, issued September 5, 2007. Traced deferred amounts to FERC Account 183.

Positive Accumulated Depreciation

Objective: To verify all Positive Accumulated Depreciation (negative depreciation expense).

Procedures: Obtained a list of all Plant Expenditures (PE) with debit balances in accumulated depreciation from the company as of December 31, 2008 by month.

EXHIBITS

Schedule 2A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2008 - December 2008

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)	4,988,103	3,420,308	3,366,536	3,480,633	4,329,772	4,631,384	5,305,640	4,861,102	4,636,354	3,768,308	3,493,081	4,439,433	[illegible]
2	True-Up Provision (Order No. PSC-07-0922-FOF-EI)	11,705	11,705	11,705	11,705	11,705	11,705	11,705	11,705	11,705	11,705	11,705	11,706	140,459
3	ECRC Revenues Applicable to Period (Lines 1 + 2)	4,999,808	3,432,013	3,378,241	3,492,338	4,341,477	4,643,089	5,317,345	4,872,807	4,648,059	3,780,013	3,505,786	4,451,139	[illegible]
4	Jurisdictional ECRC Costs													
	a O & M Activities (Schedule 5A, Line 9)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	b Capital Investment Projects (Schedule 7A, Line 9)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	c Total Jurisdictional ECRC Costs	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
5	Over/(Under) Recovery (Line 3 - Line 4c)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
6	Interest Provision (Schedule 3A, Line 10)	5,387	2,577	569	(1,217)	(1,880)	(1,429)	(344)	684	2,779	[illegible]	425	(12)	[illegible]
7	Beginning Balance True-Up & Interest Provision													
	a Actual Total for True-Up Period 2007	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
	b Final True-Up from January 2006 - December 2006 (Order No. PSC-07-0922-FOF-EI)	2,258,385	2,258,385	2,258,385	2,258,385	2,258,385	2,258,385	2,258,385	2,258,385	2,258,385	2,258,385	2,258,385	2,258,385	2,258,385
8	True-Up Collected/(Refunded) (see Line 2)	(11,705)	(11,705)	(11,705)	(11,705)	(11,705)	(11,705)	(11,705)	(11,705)	(11,705)	(11,705)	(11,705)	(11,706)	(140,459)
9	Adjustments													
10	End of Period Total True-Up (Lines 5 + 6 + 7a + 7b + 8)	1,802,635	408,116	(91,436)	(871,881)	(733,680)	(461,457)	114,075	253,542	701,181	329,353	(68,795)	41,502	[illegible]

Schedule 3A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 20[illegible] - December 20[illegible]

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)	1,610,930	1,602,635	408,116	(97,436)	(971,881)	(775,480)	(431,483)	144,671	753,343	791,381	529,233	(48,745)	
2 Ending True-Up Amount Before Interest (Line 1 + Schedule 2A, Lines 5 + 8)	1,591,240	400,550	(97,8[illegible])	(978,884)	(753,768)	(679,856)	115,717	722,440	788,803	527,064	(76,178)	41,604	
3 Total of Beginning & Ending True-up (Lines 1 + 2)	3,201,170	2,003,173	310,271	(1,066,140)	(1,725,646)	(1,425,724)	(536,766)	867,131	1,542,147	1,318,284	450,864	(35,141)	
4 Average True-Up Amount (Line 3 x 1/2)	1,600,5[illegible]	1,004,087	155,136	(534,070)	(862,823)	(712,862)	(268,133)	433,566	771,073	659,142	225,432	(14,070)	
5 Interest Rate (First Day of Reporting Business Month)	0.049[illegible]	0.050[illegible]	0.01[illegible]	0.0[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
6 Interest Rate (First Day of Subsequent Business Month)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
7 Total of Beginning and Ending Interest Rates (Line 5 + Line 6)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
8 Average Interest Rate (Line 7 x 1/2)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
9 Monthly Average Interest Rate (Line 8 x 1/12)	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	
10 Interest Provision for the Month (Line 4 x Line 9)	5,382	2,571	309	(3,217)	(1,872)	(1,427)	(546)	304	1,377	2,370	425	(12)	9,08[illegible]

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Gulf Environmental Program Update dated 4/1/09

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

Docket No. 090007-EI

GULF POWER COMPANY
ENVIRONMENTAL COMPLIANCE PROGRAM UPDATE

for the

Clean Air Interstate Rule
Clean Air Visibility Rule

April 1, 2009

GULF POWER
A SOUTHERN COMPANY

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1.0 EXECUTIVE SUMMARY

Since the Clean Air Act Amendments (CAAA) were passed by Congress in 1990, Gulf Power Company (Gulf Power or Gulf) has reviewed and updated its environmental compliance plan as needed on an on-going basis. The goal of this process is to identify reasonable, cost-effective compliance strategies that will minimize the impact on Gulf Power's customers while achieving environmental objectives and assuring compliance with all environmental requirements.

This document is an update of Gulf's original compliance plan approved by the Florida Public Service Commission (Commission or FPSC) in Order No. PSC-07-0721-S-EI. That plan: (a) addressed the requirements of the Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), and the Clean Air Visibility Rule (CAVR); (b) reviewed the decision process for assuring compliance at Gulf Power; and (c) provided cost estimates for incorporating these requirements at Gulf Power. The document reviewed the specific issues, timing, alternatives, process, and costs necessary for compliance with the new federal rules and the corresponding implementation programs developed by the Florida Department of Environmental Protection (FDEP) and the Mississippi Department of Environmental Quality (MDEQ).

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 compliance plan. That stipulation identified 10 specific components, Phase I, of Gulf's plan as being reasonable and prudent for implementation and set forth a process for review in connection with the three remaining components of the plan. On August 14, 2007, the Commission voted to approve the stipulation with the proviso that Gulf provide an annual status report regarding cost-effectiveness and prudence of the phases in its Plan into which the Company is moving. On September 18, 2008, the Company filed its first annual compliance plan update, which was approved by the FPSC on November 4, 2008.

Since the Commission's approval of Gulf's compliance plan in 2007, there have been a number of developments. Gulf has addressed in several of its intervening filings, as well as in the annual update, changes to schedules of approved projects, such as the addition and cancellation of Activated Carbon Injection (ACI) at Plant Daniel and other compliance plan changes. However, there have been two significant court decisions that have had and will have further impact on Gulf's compliance plan. In February 2008 the District of Columbia Court of Appeals issued an opinion vacating the Environmental Protection Agency's (EPA) CAMR. The vacatur became effective with the issuance of the court's mandate on March 14, 2008, nullifying CAMR mercury emission control obligations and monitoring requirements. In July 2008, in response to petitions brought by certain states and regulated industries challenging particular aspects of CAIR, the U.S. District Court of Appeals for the District of Colombia issued a decision vacating CAIR in its entirety and remanding it to the EPA for further action consistent with its opinion. On December 23, 2008, however, the Court altered its July decision in response to a rehearing petition and remanded CAIR to the EPA without vacatur, thereby leaving CAIR compliance requirements in place while the EPA develops a revised rule. The Court did not impose a particular schedule by which EPA must alter CAIR but did remind EPA that they did not intend to grant an indefinite stay of the effectiveness of their decision. The States of Florida and Mississippi have EPA-approved plans to implement this rule.

This document addresses Gulf's ongoing compliance projects and the reasons Gulf plans to continue these projects. Florida and Mississippi's EPA approved CAIR implementation plans must be met. Gulf Power's compliance plan will be impacted by factors such as: implementation of these rules; the result of EPA's promulgation of a CAIR replacement rule; EPA's, FDEP's, and the MDEQ's responses to court decisions vacating CAMR; changes to existing environmental laws and regulations, the cost of emissions allowances, performance of emission control equipment; and any change in the use of coal. Based on these factors, future environmental compliance costs will continue to be incurred, and projections will be revised. The timing of the requirements and costs incurred will be a function of the compliance options selected, fuel burn, energy demand, fuel sulfur content, availability and prices for allowance purchases, natural gas prices, performance of emission control equipment, and other variables.

A capital and operations and maintenance (O&M) cost summary for Gulf's compliance plan is provided in Table 1.0-1. Detailed capital and O&M costs are provided in Section 3 of this document.

As noted in the Commission's approval of Gulf's original compliance plan, the plan will likely evolve over time, so, at present, only Phase I projects have been approved. Gulf has changed the implementation of some of those projects. This document reflects all the changes to Gulf's compliance plan since the initial plan was approved. As circumstances become clearer, it is reasonable to anticipate further changes.

Gulf Power has remained in compliance with all requirements of the CAAA and has addressed local concerns regarding potential ozone nonattainment in Pensacola and along the Gulf Coast. Implementation of the plan described in this document will help assure continued compliance; however, new ozone standards may still result in the Pensacola area being designated as non-attainment. The FDEP recently released a list of non-attainment areas for ozone to EPA that included both the Pensacola Metropolitan area and Bay County. EPA is expected to make the final designations early next year.

Beyond CAIR and CAVR, many of the future regulatory requirements, especially those needed to attain current and future ozone and fine-particulate ambient standards and reasonable progress visibility requirements, will be aimed at further nitrogen oxide (NO_X) and sulfur dioxide (SO_2) reductions. However, many of these anticipated requirements are not yet fully developed. With the vacatur of CAMR, it is anticipated that EPA will adopt a rule for maximum achievable control technology (MACT) for power plant mercury emissions and potentially other hazardous air pollutants (HAPs). As mentioned earlier, the EPA has been ordered to promulgate a new rule addressing the issues in the D.C. Circuit Court's July 2008 CAIR decision. In addition, there are multiple state, federal and international initiatives regarding greenhouse gases (GHG), particularly carbon dioxide (CO_2), pending. If adopted, these rules could further impact Gulf's compliance plan. All of this uncertainty reinforces the need for a flexible, robust compliance plan. Accordingly, as decision dates for equipment purchases approach, and as better information relative to regulatory and economic drivers becomes available, the analysis will be updated as needed to enable the selection of the most reasonable and cost-effective compliance alternatives while maintaining future flexibility in the plan.

Table 1.0-1
Projected 2009-2018 Compliance Plan
Capital and O&M Costs by Plant

Plant	Phase I Capital Expenditures ($M)	Phase II Capital Expenditures ($M)	Phase I O&M Expenses ($M)	Phase II O&M Expenses ($M)
Crist	463	0	184	0
Daniel*	315	206	24	8
Smith	1	307	37	4
Scholz	0	0	0.2	0
TOTAL	779	513	245	12

*Costs for Gulf Power's ownership portion of Plant Daniel in Mississippi.
Note: Allowance cost projections are not included in Table 1.0-1

2.0 REGULATORY AND LEGISLATIVE UPDATE

This section provides a regulatory and legislative update and review of the CAIR, CAMR, and CAVR.

2.1 CLEAN AIR INTERSTATE RULE

In March 2005, the EPA published the final CAIR, a rule that addresses transport of SO_2 and NO_X emissions that contribute to nonattainment of the ozone and fine particulate matter National Ambient Air Quality Standards (NAAQS) in the Eastern United States. This cap and trade rule addresses power plant SO_2 and NO_X emissions that were found to contribute to non-attainment of the 8-hour ozone and fine particulate matter standards in downwind states. Twenty-eight eastern states, including Florida and Mississippi, are subject to the requirements of the rule. The rule calls for additional reductions of NO_X and SO_2 to be achieved in two phases, 2009/2010 and 2015, as shown in Table 2.1-1.

Table 2.1-1

CAIR Emission Reduction Requirements

Emissions	Phase I reduction from acid rain allocations or current emissions	Phase II reduction from current allocations or current emissions
SO_2	50% (2010)	66% (2015)
NO_X	50% (2009)	65% (2015)

On July 11, 2008, in response to petitions brought by certain states and regulated industries challenging particular aspects of CAIR, the Circuit Court of Appeals for the District of Columbia issued a decision vacating CAIR in its entirety, and remanding it to EPA for further action consistent with its opinion. In December 2008, however, the U.S. Circuit Court altered its July 2008 decision in response to a rehearing petition and remanded CAIR to the EPA without vacatur, thereby leaving CAIR compliance requirements in place while EPA develops a revised rule. The States of Florida and Mississippi have EPA-approved plans to implement this rule. Compliance with these plans will be accomplished by the installation of additional emission controls at the Company's coal-fired facilities and/or by the purchase of emission allowances. Decisions regarding Gulf's CAIR compliance strategy were made jointly with the CAMR and CAVR compliance plans due to co-benefits of proposed controls.

Gulf Power's overall compliance strategy has been developed in response to numerous federal and state regulatory requirements, many of which remain unaffected by the court's ruling. The court's decision has the potential to impact future decision making regarding capital expenditures, the installation and operation of pollution control equipment, the purchase of emissions allowances, and the carrying cost of the existing emissions allowances. The ultimate impact of this decision, if any, cannot be determined at this time and will depend on subsequent legal action, including future EPA and State rulemaking. However, what is clear for the present is that Gulf must comply with Florida and Mississippi's EPA approved CAIR implementation plans.

2.2 CLEAN AIR MERCURY RULE

In March 2005, the EPA published the final CAMR, a cap and trade program for the reduction of mercury emissions from coal-fired power plants. The rule set caps on mercury emissions to be implemented in two phases, 2010 and 2018, and provided for an emission allowance trading market.

The final CAMR was challenged in the U.S. Court of Appeals for the District of Columbia Circuit. The petitioners alleged that the EPA was not authorized to establish a cap-and-trade program for mercury emissions and instead the EPA must establish Maximum Achievable Control Technologies (MACT) standards for coal-fired electric utility steam generating units. On February 8, 2008, the court issued an opinion vacating the CAMR. The vacatur became effective with the issuance of the court's mandate on March 14, 2008, nullifying CAMR mercury emission control obligations and monitoring requirements.

With CAMR voided, electric generating facilities are no longer required to install mercury controls to meet the CAMR emission limits and are not required to install mercury monitoring equipment to meet the January 2009 monitoring deadline. EPA is expected to initiate a rulemaking proceeding to develop MACT standards for power plants; however, this process could take multiple years to complete. The CAMR court decision does not impact state rules that may continue to be developed in Florida. In addition, it is anticipated that emission controls installed to achieve compliance with CAIR, the Acid Rain Program, ambient air quality rules, and other environmental requirements will continue to result in mercury emission reductions. Future rulemakings could require emission reductions more stringent than those required by the CAMR.

2.3 CLEAN AIR VISIBILITY RULE

The Clean Air Visibility Rule (formerly called the Regional Haze Rule) was finalized in July 2005. The goal of this rule is to restore natural visibility conditions in certain areas (primarily national parks and wilderness areas) by 2064. The rule involves (1) the application of Best Available Retrofit Technology (BART) to certain sources built between 1962 and 1977, and (2) the application of any additional emissions reductions which may be deemed necessary for each designated area to achieve reasonable progress by 2018 toward the natural conditions goal. Thereafter, for each 10-year planning period, additional emissions reductions will be required to continue to demonstrate reasonable progress in each area during that period. For power plants, the CAVR allows states to determine that the CAIR satisfies BART requirements for SO_2 and NO_X. Extensive studies were performed for each of the company's affected units to demonstrate that additional PM controls were not necessary under BART. States are currently completing implementation plans that contain strategies for BART and any other measures required to achieve the first phase of reasonable progress. The Florida Regional Haze rule, Chapter 62 Part 296.340, F.A.C., requires BART compliance as expeditiously as practicable, but not later than December 31, 2013. The Mississippi Regional Haze State Implementation Plan (SIP) has been submitted to EPA and is currently under review.

3.0 GULF'S COMPLIANCE PLAN

3.1 GULF POWER'S ELECTRIC GENERATING SYSTEM

Gulf Power owns and operates three fossil–fueled generating facilities in Northwest Florida (Plants Crist, Smith and Scholz). Gulf also owns a 50 percent undivided ownership interest in Unit 1 and Unit 2 at Mississippi Power Company's Plant Daniel. This fleet of generating units consists of ten fossil steam units, one combined cycle (CC) unit and one combustion turbine (CT). The name plate generating capacity of Gulf's generating fleet affected by CAIR and/or CAVR is 2,783 Megawatts (MW).

A summary of the Compliance Plan capital projects and associated expenditures through 2018 is provided in Table 3.1-1. The projected plant O&M expenses associated with the capital projects are included in Table 3.1-2. The cost information is provided by plant and by project.

Table 3.1-1
Compliance Plan Capital Expenditures
$ in Thousands

A B C D E F G H I J

	Prior Years**	2009	
By Plant			[redacted]
Plant Crist			
Mercury Monitoring			
Unit 6 SCR	5,270	14,215	
Units 4-7 Scrubber	332,229	251,585	
Plant Scholz			
Mercury Monitoring	556		
Plant Smith			
Unit 2 Baghouse*			
Unit 1 SNCR	7,603	696	
Unit 2 SNCR	2,254	229	
Mercury Monitoring	1,964		
Units 1-2 Scrubber *			
CAIR Parametric Monitor	229		
Plant Daniel			
Mercury Monitoring	7	(7)	
Unit 1 SCR*			
Unit 2 SCR*			
Units 1 & 2 Scrubber			
Unit 1 SNCR			
Unit 1 Low NOx Burners	170	1,274	
Unit 2 SNCR			
Unit 2 Low NOx Burners	3,265	161	
By Project			
Mercury Monitoring	2,527	(7)	
SCRs	5,270	14,215	
Scrubbers	332,229	251,585	
SNCRs	9,857	925	
Baghouse			
CAIR Parametric Monitor	229		
Low Nox Burners	3,435	1,435	
Annual Total	353,547	268,153	

* Phase II projects that have not been approved for ECRC recovery
** 2006-2008 expenditures
Expenditures presented for Plant Daniel represent Gulf's ownership portion.
Allowance cost projections are not included in Table 3.1-1

Table 3.1-2
Compliance Plan Plant O&M Expenses
$ in Thousands

A B C D E F G H I J

	2008	2009	[redacted]
By Plant			
Plant Crist			
Mercury Monitoring			
Unit 6 SCR			
Units 4-7 Scrubber	366	1,739	
Plant Scholz			
Mercury Monitoring		18	
Plant Smith			
Unit 2 Baghouse*			
Unit 1 SNCR		1,700	
Unit 2 SNCR		1,640	
Mercury Monitoring			
Units 1-2 Scrubber*			
CAIR Parametric Monitor			
Plant Daniel			
Mercury Monitoring	145	7	
Unit 1 SCR*			
Unit 2 SCR*			
Units 1&2 Scrubber			
Units 1 & 2 SNCR(s)			
Unit 1 Low NOx Burners			
Unit 2 Low NOx Burners			
Activated Carbon Injection	71		
By Project			
Mercury Monitoring	145	25	
SCRs			
Scrubbers	366	1,739	
SNCRs		3,340	
Baghouse			
CAIR Parametric Monitor			
Low Nox Burners			
Activated Carbon Injection	71		
Annual Total	582	5,104	

* Phase II projects that have not been approved for ECRC recovery
Expenses presented for Plant Daniel represent Gulf's ownership portion.
Allowance cost projections are not included in Table 3.1-2

3.2 COMPLIANCE OPTIONS

A comprehensive environmental compliance planning evaluation considers a range of options for economically meeting the energy needs of Gulf Power's customers. Gulf Power investigated four major options for environmental compliance:

- Dependence on allowance purchases
- Fuel switching
- Retrofit of environmental emission controls to existing generating units
- Retirement of existing generating units and replacement with new or purchased generation

Combinations of these options were also considered.

3.2.1 Allowance Purchase Option

The CAIR rule proposed a new cap and trade program. Cap and trade programs use a market-based approach to reduce emissions. The program sets a cap, or limit, for each pollutant such as SO_2 and NO_X, which is then divided into emission allowances that are allocated to each affected source. Sources are allowed to determine the most reasonable, cost-effective way to comply. Facilities may install environmental emission controls, use fuel switching, replace the generating units, rely on the emission allowance market, or use some combination of these options.

In addition to the already existing SO_2 (acid rain) and seasonal NO_X (ozone) allowance markets, the CAIR introduced an additional allowance market for annual NO_X.

3.2.2 Fuel Switching Option

Fuel switching refers to instances where an electric generating unit's primary fuel is changed to reduce emissions. For certain facilities, NO_X emissions can be reduced by burning high-moisture, low-Btu sub-bituminous coals, while mercury emissions can be reduced by utilizing coal lower in mercury content. In Gulf's case, fuel switching to lower sulfur coal was shown under the Acid Rain Program to be a cost effective means for reducing emissions of SO_2.

3.2.3 Retrofit Options

Retrofit options refer to additional environmental emission controls that can be installed on existing generating units. As discussed in Section 2, affected coal-fired electric generating units would be required to comply with SO_2 and NO_X limits under CAIR and CAVR, if the units are to continue to operate. These reductions may be met by installing additional SO_2, and NO_X

emission controls on existing units. Currently, the proven control technology of choice for SO_2 reduction is wet scrubbing. For NO_X removal, there are a number of proven emission controls available such as Selective Catalytic Reduction (SCR), Selective Non-Catalytic Reduction (SNCR), and Low NO_X Burners (LNBs).

3.2.4 Retirement and Replacement Option

A retirement and replacement evaluation is used to compare retrofit compliance options to premature retirement and replacement of specific generating units in order to determine the most reasonable, cost-effective compliance option. These evaluations are performed at two levels of detail: (1) a less detailed retirement/replacement evaluation and (2) a more detailed site specific replacement evaluation. The retirement option is typically more applicable to smaller, older, less efficient coal plants that cannot financially support the addition of environmental controls. The evaluation methodology and the evaluation results are discussed in Section 3.3.4.

3.3 GULF'S EVALUATION OF COMPLIANCE OPTIONS

3.3.1 Evaluation of Allowance Purchase Option

The two existing emissions allowance markets (SO_2 and seasonal NO_X) have proven to be fundamentally driven by supply and demand. However, over time, many speculative investors have begun entering the allowance markets, particularly the SO_2 market, introducing considerable volatility and uncertainty concerning the price and availability of allowances.

The costs of compliance with the SO_2 programs represent a major portion of Gulf Power's total environmental compliance program cost. With the high price volatility, the future price and availability of allowances cannot be treated as predictable; therefore, depending solely on the market for SO_2 compliance presents a large risk for Gulf Power's customers. Additionally, should allowances not be available, Gulf Power might be forced to operate higher cost units while curtailing operation of lower cost units in order to maintain compliance.

The CAIR program introduced an additional allowance market for annual NO_X. This market was expected to emerge as soon as the states finalized their implementation plans. Indeed, EPA has populated the annual NO_X accounts. Due to the December 2008 court decision leaving CAIR intact, these allowances are necessary for continued operation after January 1, 2009. In addition, the seasonal NO_X program will be implemented in Florida and Mississippi.

Total dependence on these commodity markets for compliance would be very risky and potentially costly for Gulf Power and its customers. The market does, however, provide realistic opportunities for reducing costs through selected and limited purchases of allowances in conjunction with other options to achieve cost effective compliance.

In summary, in order for the allowance market based approach to be an appropriate solution for Gulf Power's compliance shortfall, these allowance markets must be established, reasonably stable, and have sufficient quantities of allowances available. Furthermore, to avoid short-term supply and demand volatility, these conditions must be met with sufficient lead time to allow time to pursue other options such as constructing emission controls. Given the timing of construction schedules and the compliance deadlines for the new rules, Gulf Power could not wait to see if stable allowance markets emerged. These overall uncertainties eliminated the exclusive use of an all allowance purchase option from consideration.

3.3.2 Evaluation of Fuel Switching Option

Fuel switching was shown under the Acid Rain Program to be cost effective for reducing emissions of SO_2. For certain facilities, NO_X emissions can be reduced by burning high-moisture, low-Btu sub-bituminous coals, and some coals are lower in mercury content than others. However, for the magnitude of emission reductions required by CAIR and CAVR, fuel switching is no longer a viable option.

3.3.3 Evaluation of Retrofit Options

Having determined that neither an all allowance plan nor an all fuel switching plan would be feasible or desirable, Gulf Power was left with the primary options of either retrofitting units or retiring and replacing units (and, if necessary, supplementing those options with allowance purchases or fuel switching). However, before making a comparison of retrofit and replacement options, Gulf Power first had to choose among competing retrofit options. Those selections of the best retrofit options were discussed in Gulf's original compliance plan and have not changed; therefore, they are not repeated here.

3.3.4 Evaluation of Retrofit versus Replacement Options

Selection between retrofit and replacement options is based upon a financial assessment of which option ultimately is expected to be the most reasonable, cost effective alternative for Gulf's customers. The analyses examines the relative cost of dispatching the System (a) with the retrofit technology in place and (b) with having retired the unit without making the retrofit and instead, replacing it with new or purchased capacity. The analyses included all Gulf Power units that would require environmental controls under Phase I of CAIR and are anticipated under CAVR.

This analysis is run at both a less detailed level (Phase I) and using a more detailed methodology (Phase II). The basic methodology is the same for both types of analyses, but the Phase I analysis employs some simplifying but more stringent assumptions. The Phase I level analysis uses a lower-cost replacement alternative than is used in the more detailed Phase II methodology (essentially peaking capacity with energy priced at the Southern electric system's marginal cost of energy instead of an equivalent amount of CC capacity replacing the unit that would be retired). Consequently, if a retrofit option passes the more stringent Phase I level analysis, it will pass the more detailed Phase II analysis that uses a higher cost, site-specific replacement option. The employment of this Phase I methodology allows a quick, yet more stringent evaluation of financial viability and is an excellent indicator of which retrofit options need a more detailed evaluation. The Phase II evaluation focuses on a comparison of continued unit operation with replacement by a CC. The detailed evaluation also includes more refined production cost modeling and cost implications to the transmission system. Changes in production cost, capital, and other fixed costs are captured in the comparison analysis to help determine the most economical option.

Phase I Methodology

The Phase I economic analysis creates a comparison of the costs over a period from the current year until the planned retirement date for each unit at which a retrofit is being contemplated. The costs of operating the retrofitted unit, its affect on system dispatch costs, and the need to purchase allowances to meet any remaining emission shortfalls (all of which are characterized as "Incremental Costs") are compared to the cost of a generic peaking unit and System replacement energy costs. To calculate those associated energy costs, Gulf assumes energy purchases from the Southern electric system at the System incremental cost. The costs associated with capacity to replace a unit and the associated energy costs are characterized as "Avoided Cost," as these are the costs that are avoided by operating the retrofitted unit.

The analysis compares the net present value (NPV) on a $/kW basis of the two cost streams over the period analyzed to determine which has the lower cost on a net present value basis. The difference between the Avoided Cost associated with replacement and the Incremental Costs of operating the retrofitted unit is characterized as "the overall net contribution of continued operation." If the replacement option cost was lower than the retrofit option cost, then this value would be negative. The control schedules are based on potential CAIR, CAVR and ozone non-attainment requirements.

Avoided Cost

Avoided cost includes capacity and energy costs. These costs are properly characterized as benefits, as they are the costs avoided due to operating the retrofitted unit. The avoidance of these costs is a benefit to Gulf Power and its customers.

Capacity costs are the costs of a peaking generator used for system reliability to meet peak loads. These costs for the replacement option in the Phase I analysis are based on a peaking capacity price forecast that assumed short-term purchases from the market until 2014 and the economic carrying cost of a self-build combustion turbine thereafter.

Energy costs in the Phase I analysis are developed using the Strategist® model. Strategist® is a production cost model commonly employed throughout both the Southern electric system and the utility industry. The avoided energy cost for each retrofitted unit is calculated by determining the average energy purchase costs during the hours the retrofitted unit operated each year. This methodology simplifies avoided energy cost calculations for use in Phase I potential retirement candidates.

Incremental Costs

Incremental costs include fuel, O&M, capital, and emission allowance costs (NO_X, SO_2, and CO_2) necessary for continued operation of the retrofitted facility. Mercury allowances were not included in the Strategist® model due to the vacatur of CAMR. Further, given that CAIR's vacatur was stayed by the Court, NO_X and SO_2 allowance costs necessary to comply were included.

The fuel and allowance price assumptions are based on Southern Company forecasts developed by polling external and internal subject matter experts. Southern Company provides primarily near term projections based on its experience with the short term markets and relies primarily on an external consultant for its long term forecast. The Strategist® model is then provided total annual fuel and emissions costs based on the economic operation of the retrofitted unit for the base case and the two CO_2 sensitivities for the remaining life of the unit. O&M costs for the retrofitted unit include labor, materials, overheads, and engineering and support services. Four-year projections of the retrofitted unit's incremental O&M costs were developed. The O&M costs of the retrofitted unit over its remaining life are calculated using a moving average of the projections for the first 4 years and escalating the resulting value for inflation.

The incremental capital costs for the remaining life of the retrofitted unit were based on capital expenditures projected for each retrofitted generating unit. These projected capital expenditures were necessary to keep the units running through the analysis period at the current level of operation. Future capital expenditures for environmental controls were also included.

Sensitivities

Gulf's September 2008 CAIR/CAMR/CAVR Compliance Plan update included the results of a Phase I base case analysis and two sensitivities that were developed around uncertainty in CO_2 legislation. These planning sensitivities were developed in order to capture variations in the operating environments that would affect the retirement dates of the units. The sensitivities were developed by Southern Company based on input from subject matter experts within Southern Company. The sensitivities were based on \$10/Ton CO_2 and \$20/Ton CO_2 (2008\$) starting in 2015 escalating at 5% above inflation. The Phase I analysis has not been updated since the September 2008 filing because Gulf's economic analyses have not been finalized using the updated 2009 planning assumptions.

Summary of Study Results

Tables 3.3-3 through 3.3-8 summarize the results of the September 2008 Phase I analysis. The tables illustrate costs and benefits of continued operation of each of the units with environmental controls over the remaining life of each unit for the base case and both CO_2 sensitivities. Assumptions for the timing and installation of environmental controls are listed at the bottom of the table. A description of each line item included in the evaluation is also included on Table 3.3-9.

In most reasonable sensitivities analyzed for Gulf's units with proposed retrofit projects, continuing to operate the existing unit with the retrofit option has a NPV lower than the cost to replace the unit. Under higher CO_2 penalties ($20/Ton) and moderate fuel prices, the evaluation indicates it would be cost effective to replace the units by 2020; however, under those conditions, the higher demand and higher related price for natural gas that would result would likely provide enough economic margin to continue to operate the coal units. Customers will also continue to benefit from the value of diversity in future fuel costs with the retrofit of existing coal units instead of Gulf increasing its reliance on gas.

The September 2008 Phase I level results indicate there is a savings shown by continuing to operate each generating unit as opposed to replacing it with new or purchased capacity and System energy purchases for both the base case (No CO_2) and $10 CO_2 sensitivity. By adding the net contribution values for the base case shown in Tables 3.3-3 through 3.3-8, the savings for Plants Crist and Daniel are $1.9 billion and $1.2 billion, respectively, under the No CO_2 case, and $1.3 billion and $0.9 billion, respectively, under the $10 CO_2 sensitivity. Under the extreme $20 CO_2 sensitivity, which does not recognize a corresponding increase in natural gas prices, Crist Units 4 through 6 and Daniel Units 1 and 2 are indicated to retire by 2020. Crist Unit 7 remains economic even under the most severe CO_2 sensitivity.

Phase II Methodology

The Phase II analysis focuses on a comparison of continued operation with retrofits to replacement by a combined cycle unit. This evaluation also includes more refined production cost modeling and cost implications to the transmission system. Changes in production cost, capital, and other fixed costs are captured in the comparison analysis to help determine the most economical option. In the September 2008 Phase II analysis the System production costs were generated with the Strategist® model using a thirty-year period (2008 – 2037) with the updated 2008 Energy Ventures Analysis, Inc (EVA) published forecasts for allowances and the Southern Company 2009 Fuel Forecast Update. Fixed costs associated with the continued operation of the existing generating units were based on projections of annual O&M and the NPV of the revenue requirements associated with incremental capital investment necessary to keep the unit operational over the 30-year evaluation period. Replacement, installation capital, fixed O&M, and continue to operate capital, are site specific costs developed by Southern Company Engineering and Construction Services. Replacement capacity costs are expressed as a credit of

Engineering and Construction Services. Replacement capacity costs are expressed as a credit of CC capacity cost for all replacement MWs that exceed the amount being replaced. The NPV of the difference between replacement cost and unit operational cost is calculated to determine the overall net contribution. The annual cost difference is present-valued and accumulated to determine if there is an economic retirement date. The units analyzed and the dates utilized in the retirement detailed analyses were determined based on the units impacted by the CAIR and CAVR control deadlines and time required for replacement combined cycles to be built. These control deadlines are based on potential CAIR, CAVR, and ozone non-attainment requirements.

As in the Phase I analysis, the September 2008 Phase II analysis incorporated the base case and two planning sensitivities that were developed around uncertainty in CO_2 legislation. These planning sensitivities were developed by Southern Company based on input from subject matter experts both externally and internally within Southern Company. The sensitivities were based on \$10/Ton CO_2 and \$20/Ton CO_2 (2008\$) starting in 2015 escalating at 5% above inflation. The units analyzed in Phase II are Crist Units 4 through 6 and Daniel Units 1 and 2. The Phase II analysis has not been updated since the September 2008 filing because Gulf's economic analyses have not been finalized using the updated 2009 planning assumptions.

<u>Plant Crist Units 4 through 6</u>

The purpose of this evaluation was to determine the economic benefits of retiring Plant Crist Units 4 through 6 in May of 2014 and replacing the units with the lowest cost option. The evaluation also included estimates of transmission cost implications and dismantlement costs associated with a potential retirement. It was assumed in this study that the replacement combined cycle unit would be placed on the Plant Crist site. The evaluation retired and replaced Crist Units 4 through 6 with one 2x1 G series CC in June of 2014, avoiding the Crist 6 SCR installation in the fall of 2012.

Crist 7 was excluded from this evaluation due to the large economic value indicated in the Phase I evaluation. Since Crist 7 already has an SCR and is scheduled to have a scrubber operational in 2009, nearly all of its environmental retrofit costs are either spent or committed. At this point in the construction of the Plant Crist scrubber, eliminating Crist Units 4 through 6 from the project scope would not result in significant, if any, cost savings. For this reason, all of the remaining cost of the Crist scrubber was allocated to Crist Unit 7. Even with this allocation, Crist Unit 7 remains the most economic choice to be controlled.

Transmission and Dismantlement Cost Assumptions

[redacted]

1
2 [redacted]

Partial dismantlement cost estimates for Crist Units 4 through 6 were based on a 2008 study. The results of that study indicated that for Crist Units 4 through 6 the projected cost is $5.5 million in 2008$.

Results

An economic evaluation of the CC replacement option was performed to compare customer costs over a thirty-year period from 2008-2037. The CC replacement option was compared back to the cost of continuing operation of Crist 4 through 6 with the SCR installed on Crist 6.

Table 3.3-1 summarizes the additional fuel (System Production Cost), capital, and O&M costs for the CC replacement options for the September 2008 base case and two sensitivity cases. It shows that the No CO_2 and \$10 CO_2 cases would result in a total cost to the customer of \$936.6 million and \$643.4 million, respectively, if Crist Units 4 through 6 were replaced with a combined cycle unit. Under the higher \$20 CO_2 penalty and the current fuel forecast, the evaluation indicated there would be a total cost to the customer of \$376.9 million, if Crist Units 4 through 6 were replaced with a combined cycle unit. Under such a high CO_2 penalty, the higher demand and related higher price for natural gas that would result would likely provide an even greater economic margin to continue to operate the coal units.

Table 3.3-1
Net Replacement Costs – Crist Units 4 through 6

[redacted]

Plant Daniel Units 1 and 2

The purpose of this evaluation was to determine the economic benefits of retiring Plant Daniel Units 1 and 2 in December of 2014 and replacing the units with the lowest cost option. The evaluation also included estimates of transmission cost implications and site closure costs associated with a potential retirement. It was assumed in this study that the replacement CC would be placed on the Plant Daniel site. The evaluation retired and replaced Daniel Units 1 and 2 with two 2x1 G series CC's in January of 2015, avoiding the Daniel Units 1 and 2 SCRs in the fall of 2014 and the spring of 2015, respectively, and the fall 2013 Scrubber installation.

Transmission and Site Closure Cost Assumptions

[redacted]

Site closure cost estimates for Daniel Units 1 and 2 were based on a 2008 study. The results of that study indicated that for Daniel Units 1 and 2, the projected cost is $33.2 million in 2008$, which included the closure of the ash pond.

Results

Table 3.3.2 summarizes the additional fuel (System Production Cost), capital, and O&M costs for the CC replacement options for the September 2008 base case and two scenarios analyzed. It showed that for the No CO_2 and $10 CO_2 cases there would be a total cost to Gulf's customers of $669.2 million and $365.0 million, respectively, to replace Daniel Units 1 and 2. Under the higher $20 CO_2 penalty, and the current fuel forecast, the evaluation indicated there would be a total cost to Gulf's customers of $50.4 million to replace Daniel Units 1 and 2. Under such a high CO_2 penalty, the higher demand and higher related price for natural gas that would result would likely provide an even greater economic margin to continue to operate the coal units.

Table 3.3-2 Net Replacement Costs – Daniel Units 1 and 2

[redacted]

A B C D

TRADE SECRET - PROTECTED

Table 3.3-3
Phase I Economic Viability Study – Crist Unit 4

1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20

[redacted]

Environmental Controls	
Scrubber	2009
SCR	N/A

A B C D

Table 3.3-4
Phase I Economic Viability Study – Crist Unit 5

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[redacted]

Environmental Controls	
Scrubber	2009
SCR	N/A

A B C D

TRADE SECRET – PROTECTED

Table 3.3-5
Phase I Economic Viability Study – Crist Unit 6

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[redacted]

Environmental Controls	
Scrubber	2009
SCR	2012

A B C D

Table 3.3-6
Phase I Economic Viability Study – Crist Unit 7

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[redacted]

Environmental Controls	
Scrubber	2009
SCR	*Existing*

	A	B	C	D

TRADE SECRET – PROTECTED

Table 3.3-7
Phase I Economic Viability Study – Daniel Unit 1

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[redacted]

Environmental Controls		
Scrubber	2013	
SCR	2014	

A B C D

TRADE SECRET - PROTECTED

Table 3.3-8
Phase I Economic Viability Study – Daniel Unit 2

1 [redacted]
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Environmental Controls	
Scrubber	2013
SCR	2015

TRADE SECRET – PROTECTED

Table 3.3-9
Phase I Economic Viability Study – Evaluation Description

Economic Screening Analysis
NPV of Study Period in 2008 $/kW

Generating Unit	*Description*
Avoided Cost Based Benefits	
Energy	The value of System lambda (marginal energy costs) during the hours the unit is running
Avoided Capacity Benefit	The projected value of peaking capacity based on the long term cost of a new CT
Avoided Cost Benefits	Total Avoided Costs
Incremental Costs	
Fuel	The fuel cost to operate the existing unit
SO_2	The cost of SO_2 emissions based on SO_2 allowance costs and unit emissions
NOx	The cost of NO_x emissions based on NO_x allowance costs and unit emissions
CO_2	The cost of CO_2 emissions based on CO_2 penalties and unit emissions
Hg	The cost of Hg emissions based on Hg allowance costs and unit emissions
O&M	The fixed and variable O&M costs (including environmental) to operate the unit
Capital Expenditures	The capital necessary to continue to operate and meet environmental compliance
Total	Total Incremental Costs
Net Contribution	Avoided Cost Benefits minus Incremental Costs
MW Capacity	Average Net Generating Capacity
Net Contribution in Thousands of Dollars	Net Contribution in Thousands of Dollars
Economic Retirement Date	Year that maximum accumulated net contribution occurs

4.0 PLANT-BY-PLANT COMPLIANCE PLAN

4.1 Plant Crist

Plant Crist is a four-unit, coal-fired electric generating facility located just north of Pensacola, Florida. Three older natural gas and oil-fired units at the site have been retired. Units 4 and 5 each have a nameplate rating of 93.7 MW and Units 6 and 7 have nameplate ratings of 369 MW and 578 MW, respectively. All four units were affected under the Acid Rain Program, and the plant has operated on low-sulfur coals since the 1990s to lower SO_2 emissions. All four units are equipped with low-NO_X burner systems. Plant Crist Units 4, 5 and 6 have SNCR systems, while Crist Unit 7 is equipped with a SCR system.

For compliance with CAIR and later with CAVR and potential NAAQS, Plant Crist needs significant SO_2 and NO_X reductions. Gulf Power forecasts that without additional emission controls Plant Crist would exceed allowance allocations for SO_2 and NO_X. Only a few technologies have demonstrated the ability to provide the needed emission reductions at the commercial scale required for Plant Crist.

For CAIR requirements at Plant Crist, a thorough assessment was conducted to compare the retrofit controls versus retirement and replacement options for compliance. As noted under Section 3.2, fuel switching or exclusive reliance on allowance purchases were eliminated as viable options for Gulf Power. Retrofit options, as well as retirement and replacement options, are each reviewed below specifically for Plant Crist.

4.1.1 Plant Crist Retrofit Options

Plant Crist Units 4 through 7 Flue Gas Desulphurization Scrubber Project

Very high levels of SO_2 emission reductions can be achieved by flue gas desulphurization. There are no other commercially available options for SO_2 emission reductions at the level needed to assure compliance with CAIR and CAVR and address the significant local concerns in the Pensacola area.

A scrubber was the only SO_2 compliance option for Crist Units 6 and 7, and because of their size and emissions, these units were the best, most cost-effective candidates for SO_2 scrubbing and mercury removal. Gulf's plan focuses on placing this scrubber on the largest Gulf Power generating units first and delaying emission controls and costs on other smaller units and plants. Installing additional ductwork and boiler controls to include Crist Units 4 and 5 was also cost-effective and increased incremental SO_2 and mercury emission reductions. The Crist scrubber project is projected to reduce SO_2 emissions by approximately 50,000 tons per year. With these reductions, Gulf Power will be able to reasonably manage compliance with its SO_2 allowance bank and some market purchases of allowances as required.

In terms of timing, the Crist scrubber was needed for Phase I CAIR compliance in 2010. Even if the CAIR rule had been vacated, Gulf Power anticipated that the Crist Scrubber project would still be needed for Crist Units 6 and 7 to comply with CAVR by 2013. Given that the Crist Scrubber project was still needed for CAVR compliance, regardless of the resolution of CAIR and the new rule that EPA promulgates, the issue Gulf faced was whether or not to defer the Crist Scrubber project for several years. During 2008, Gulf determined that the Crist Scrubber project should proceed for a variety of reasons. First, over $175 million of equipment had already been ordered. Second, significant construction had already occurred, and the construction workforce had been fully mobilized; deferral would have significantly increased the total project costs. The project was approximately 55% complete at the end of 2008. Demobilization would have meant the potential loss of personnel already on site. Deferral for three years until 2012 to meet 2013 CAVR requirements would have increased the project construction cost by approximately $53 million. The associated increase in AFUDC, which Gulf would seek for recovery, would have been at least $45 million. Thus, deferral would have cost around $100 million. Third it was also reasonable to anticipate that EPA and/or FDEP would act again to address the same issues in the replacement to the CAIR rule when it is developed. If they do, the scrubber project would continue to be the best, most cost-effective means of limiting SO_2 and mercury emissions, with Gulf potentially facing increased costs in order to meet accelerated in- service dates.

Plant Crist Unit 6 SCR Project

The Plant Crist Unit 7 SCR became operational in 2005, significantly reducing emissions of NO_X from the plant. This project was called for under an agreement with the FDEP. The agreement also called for additional NO_X reductions at Plant Crist Units 4 through 6 up to and including a SCR for Unit 6. Additional NO_X reductions are needed at Plant Crist, and only SCR technology will provide the additional increment needed. The SCR on Unit 6 will be important for Pensacola to achieve attainment with the new 8-hour ozone standard and addresses significant local pressures to continue NO_X reductions from the plant. In addition, the Crist Unit 6 SCR was also needed for CAIR and CAMR compliance. While CAMR compliance is no longer required, CAIR requirements still remain applicable. The Crist Unit 6 SCR will still be needed to satisfy FDEP requirements, the new 8-hour ozone standard, and local pressure to reduce NO_X emissions. Gulf has deferred the in-service date for the Crist Unit 6 SCR from 2010 to 2012.

4.1.2 Plant Crist Comparison of Retrofit versus Retirement and Replacement

The initial selection between retrofit and retire/replacement options for Plant Crist was based upon a financial assessment and analysis to determine the most reasonable, least cost option for Gulf Power and its customers. The analysis examined the relative cost of dispatching the Gulf system (a) with the retrofit technology in place and (b) with having retired the Crist unit(s) without making the retrofit and instead, replacing it with capacity from another generation source.

This analysis was run at both a less detailed level (Phase I) and using a more detailed methodology (Phase II). The basic methodology was the same for both types of analyses, but the Phase I analysis employed some simplifying but more stringent assumptions. For Phase I, the costs of operating the retrofitted units and its affect on system dispatch costs and the need to purchase allowances to meet any remaining emissions (all of which are characterized as "incremental costs") were compared to the cost of a generic peaking unit and associated energy costs. The September 2008 Phase I level results indicated there is a savings shown by continuing to operate each generating unit as opposed to replacing it with new or purchased capacity and System energy purchases for both the base case (No CO_2) and \$10 CO_2 sensitivity. The projected NPV cost savings or benefit to Gulf and its customers for Gulf's Environmental compliance plan for Plant Crist ranged from \$0.8 billion - \$1.9 billion over the period 2008 through the affected units' planned retirement dates.

The Phase II analysis focused on a comparison of continued operation with unit replacement by a combined cycle and included Crist Units 4, 5, and 6. This evaluation also included more refined production cost modeling and cost implications to the transmission system. Changes in production cost, capital and other fixed costs were captured in the comparison analysis to help determine the most economical option. The September 2008 Phase II results showed that the No CO_2 and \$10 CO_2 cases would result in a total cost to the customer of \$936.6 million and \$643.4 million, respectively, if Plant Crist Units 4, 5, and 6 were retired and replaced with a new combined cycle unit. Under the higher \$20 CO_2 penalty and the 2008 fuel forecast the evaluation indicated it would be a total cost to the customer of \$376.9 million if Plant Crist Units 4, 5, and 6 were retired and replaced with a new combined cycle unit. Under such a high CO_2 penalty, the higher demand and higher related price for natural gas that would result would likely provide an even greater economic margin to continue to operate the coal units.

4.1.3 Plant Crist Emission Monitoring Requirements

Mercury continuous emission monitoring systems for Plant Crist Units 4 through 7 and the common scrubber stack were included as part of Gulf's original CAIR, CAMR and CAVR compliance plan approved by the Commission. 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 at Plant Crist 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. With CAMR voided, electric generating facilities are no longer required to install mercury monitoring equipment to meet the January 2009 monitoring deadline. In response to the CAMR vacatur, Gulf has delayed further mercury monitoring capital costs until at least 2010.

4.1.4 Conclusions for Plant Crist

Based on this assessment, the retrofit of Crist Units 4 through 7 with a single flue gas desulphurization scrubber and the addition of a SCR on Unit 6 are the best options for compliance with CAIR, CAVR, the new 8-hour ozone standard, potential mercury regulation and a potential fine particulate NAAQS. These are the only technologies that offer the necessary emission reductions for SO_2 and NO_X and when used together, the scrubber and the SCRs on Units 6 and 7 will capture mercury. The scrubber is anticipated to be required as part of the CAVR "reasonable progress program." Further fuel switching will not reduce emissions to the required level. Allowance purchases are too uncertain and risky as a sole compliance option, especially for annual NO_X. The September 2008 Phase II analysis indicated that retirement and replacement of the units with a combined cycle unit is not economically feasible relative to retrofit of the existing units under all the CO_2 compliance cost scenarios analyzed.

4.2 Plant Daniel

Gulf Power's ownership interest at Plant Daniel is associated with two coal-fired electric generating units that each have a nameplate rating of 548.2 MW. Gulf Power and Mississippi Power Company each own 50 percent of Daniel Units 1 and 2. The plant is operated by Mississippi Power employees. The facility is located just north of Pascagoula, Mississippi, with direct transmission access across Alabama and into Florida. Both coal-fired units were affected under the Acid Rain Program and have operated on low-sulfur coals since the 1990s to lower SO_2 emissions. These New Source Performance Standards (NSPS) units are relatively low NO_X emitters, and as a result, Gulf and Mississippi Power have been able to delay installation of controls and associated costs required under the Acid Rain Program.

For compliance with CAIR and later with CAVR, Plant Daniel Units 1 and 2 need significant SO_2 and NO_X reductions. Only a few technologies have demonstrated the ability to provide the needed emission reductions at the commercial scale required for the coal units at Plant Daniel. In light of the CAIR and CAMR developments, some of the proposed Plant Daniel projects have been canceled or deferred.

For CAIR and CAVR requirements at Plant Daniel Units 1 and 2, an assessment was conducted to compare retrofit controls versus retirement and replacement options for compliance. As noted under Section 3.2, further fuel switching and complete reliance on allowance purchases were eliminated as viable options for all of Gulf Power's units, including its share of Plant Daniel Units 1 and 2. Retrofit options, as well as and retirement and replacement options, are each reviewed below specifically for Plant Daniel.

4.2.1 Plant Daniel Retrofit Options

Plant Daniel Unit 1 and Unit 2 Flue Gas Desulfurization Scrubber Project

Very high levels of SO_2 emission reductions can be achieved by flue gas desulfurization. There are no other commercially available options for SO_2 emission reductions at the level needed to assure compliance with CAIR and CAVR.

The Daniel scrubber project continues to be an effective means of reducing SO_2 and mercury emissions. It is still anticipated that this scrubber project may be required for CAVR compliance, even if it is not required for compliance with CAIR or potential mercury regulation. These large, co-owned units are the most efficient units owned by Gulf Power. A wet scrubber has been determined to be the only viable SO_2 retrofit compliance option for Plant Daniel.

The Daniel scrubber project is projected to reduce Gulf's SO_2 emissions by approximately 14,000 tons per year (Gulf Power ownership share). With these reductions, Gulf Power will be able to reasonably manage compliance using its SO_2 allowance bank and some market purchases of allowances as required. The scrubber is currently scheduled for completion in 2013, but its timing will continue to remain flexible based on the status of environmental regulations. For CAIR, the scrubber would minimize the reliance on a very volatile SO_2 allowance market and assure compliance for Plant Daniel Units 1 and 2.

Plant Daniel NO_X Reduction Projects

Additional NO_X controls were scheduled for Plant Daniel Units 1 and 2 under the Phase I CAIR annual and seasonal NO_X cap and trade allowance programs. The Daniel Unit 1 and 2 Low NO_X burners were planned for Phase I CAIR annual and seasonal NO_X cap and trade allowance programs. The Daniel Unit 2 Low NO_X burners were installed during 2008. The Daniel Unit 1 Low NO_X burner project that was originally scheduled to be placed in-service during 2009 had been delayed during 2008, pending the outcome of the CAIR decision. Now that the CAIR rule has been remanded to EPA and remains in effect, the Low NO_x burner project at Daniel Unit 1 has been rescheduled to be placed in-service during 2010.

Plant Daniel Units 1 and 2 were previously scheduled to receive SNCR retrofits in 2011 and 2012, respectively. Expenditures for these projects were projected to begin in 2009. Plant Daniel planned to operate the SNCRs until the SCRs were placed in-service. The SNCR projects have since been removed from the compliance schedule, and the SCR installation has been accelerated by two years. The Plant Daniel Units 1 and 2 SCRs are planned for operation in 2014 and 2015, respectively, to help meet the requirements of CAIR and 8-hour ozone nonattainment. The SCR projects have been accelerated based on the new 8-hour ozone standard that Gulf anticipates will require these controls in an earlier time period than previously planned.

These SCRs, along with the Unit 1 and 2 scrubber, also provide a co-benefit of significantly reducing mercury emissions. The schedule for these proposed SCRs remains flexible and will be continuously re-evaluated. While CAMR compliance is no longer required, CAIR requirements still remain applicable. The Daniel SCRs will also be needed to achieve attainment with the new 8-hour ozone standard.

Plant Daniel Activated Carbon Injection

During 2007, capital expenditures for Activated Carbon Injection systems at Plant Daniel were added to Gulf's compliance plan. The ACI projects were scheduled to be placed in-service by January 1, 2010 in anticipation of CAMR Phase I. The projects were added due to concerns that the mercury allowance market would not develop in time to ensure compliance during the first year of Phase I.

Based on the vacatur of the CAMR ruling, the ACI projects have been removed from the compliance schedule and budget projections. The need for ACI at Plant Daniel will be reexamined as new mercury regulation emerges.

4.2.2 Plant Daniel Comparison of Retrofit versus Retirement and Replacement

Selection between retrofit and retirement/replacement options for Plant Daniel was based upon a financial assessment and analysis to determine the least cost option for Gulf Power and its customers. The analysis examined the relative cost of (a) completing the retrofit project and operating the retrofitted unit with (b) retiring the Daniel units without making the retrofit and instead, replacing them with capacity from another generation source.

This analysis was run at both a less detailed level (Phase I) and using a more detailed methodology (Phase II). The basic methodology was the same for both types of analyses, but the Phase I analysis employed some simplifying but more stringent assumptions. For Phase I, the costs of operating the retrofitted units and its affect on system dispatch costs and the need to purchase allowances to meet any remaining emissions (all of which are characterized as "incremental costs") were compared to the cost of a generic peaking unit and associated energy costs. The September 2008 Phase I level results indicated there was a savings shown by continuing to operate each generating unit as opposed to replacing it with new or purchased capacity and System energy purchases for both the base case (No CO_2) and \$10 CO_2 sensitivity. The projected NPV cost savings or benefit to Gulf and its customers for Gulf's Environmental compliance plan for Plant Daniel ranged from \$0.6 billion - \$1.2 billion over the period 2008 through the affected units' planned retirement dates.

The Phase II analysis focused on a comparison of continued operation with unit replacement by a combined cycle. This evaluation also included more refined production cost modeling and cost implications to the transmission system. Changes in production cost, capital and other fixed costs were captured in the comparison analysis to help determine the most economical option. The September 2008 Phase II results showed that for the No CO_2 and

$10 CO_2 cases there would be a total cost to Gulf's customers of $669.2 million and $365.0 million, respectively, if Plant Daniel Units 1 and 2 were replaced instead of being retrofitted. Under the higher $20 CO_2 penalty and the 2008 fuel forecast, the evaluation indicated there would be a total cost to Gulf's customers of $50.4 million, if Plant Daniel Units 1 and 2 were replaced instead of being retrofitted. Under such a high CO_2 penalty, the higher demand and higher related price for natural gas that would result would likely provide an even greater economic margin to continue to operate the coal units.

4.2.3 Plant Daniel Emission Monitoring Requirements

Based on the 2008 CAMR vacatur, the Daniel mercury monitors have been removed from the compliance schedule and the budget. This decision will be reexamined as new mercury regulation emerges.

4.2.4 Conclusions for Plant Daniel

Based on this assessment, the retrofit of Daniel Units 1 and 2 with a flue gas desulphurization scrubber, the installation of low-NO_X combustion controls, and the addition of SCRs on both units are the best options for compliance with CAIR, CAVR, and the 8-hour ozone standard at Plant Daniel. These technologies offer the necessary emission reductions for SO_2, NO_X, and when used together, the scrubber and the SCRs will also capture mercury. The scrubber may also be required as part of the CAVR "reasonable progress program." Fuel switching will not reduce emissions to the required level. Allowance purchases are too uncertain and risky as a sole compliance option, especially for annual NO_X. The Phase II analysis indicated that retirement and replacement of the units with a combined cycle unit is not economically feasible relative to retrofit of the existing units under all of the CO_2 compliance cost scenarios analyzed.

4.3 Plant Smith

Plant Smith includes two coal-fired electric generating units (Unit 1 and Unit 2) along with an oil-fired combustion turbine and a natural gas-fired combined cycle unit. The facility is located just north of Panama City, Florida. Plant Smith Unit 1 has a nameplate rating of 149.6 MW, and Unit 2 has a nameplate rating of 190.4 MW. Both coal-fired units were affected under the Acid Rain Program, and the plant has operated on low-sulfur coals since the 1990s to lower SO_2 emissions. Both units are also equipped with low-NO_X combustion systems. Unit 1 has special low-NO_X burner tips, and Unit 2 has low-NO_X burners and separated overfired air.

For compliance with CAIR, the new 8-hour ozone standard, and later with CAVR, Plant Smith needs significant SO_2 and NO_X reductions. Only a few technologies have demonstrated the ability to provide the needed emission reductions at the commercial scale required for Plant Smith.

For CAIR and CAVR requirements at Plant Smith, an assessment was conducted to compare retrofit controls versus retirement and replacement options for compliance. As noted under Section 3.2 fuel switching and exclusive reliance on allowance purchases were eliminated as viable options for Gulf Power. Retrofit options and retirement and replacement options are each reviewed below specifically for Plant Smith.

4.3.1 Plant Smith Retrofit Options

Plant Smith SNCR and NO_X Reduction Projects

Installation of SNCRs for Plant Smith Units 1 and 2 are needed for Phase I CAIR compliance in 2009. In addition to CAIR compliance, the SNCRs are needed to assist in maintaining local compliance with the more stringent 8-hour ozone standard. The Smith Unit 2 SNCR was placed in-service in the fall of 2008, and the Smith Unit 1 SNCR will be placed in-service during the spring of 2009.

Plant Smith Units 1 and 2 Flue Gas Desulfurization Scrubber Project

The Plant Smith scrubber project has been included in the Gulf Power environmental compliance plan because the requirements of CAVR will likely lead to a scrubber being required for Plant Smith Units 1 and 2. This decision is based upon anticipated CAVR command and control requirements. In addition, the scrubber will provide the added benefit of reducing mercury emissions. The scrubber project is currently planned for operation in 2017. This schedule and decisions about the Plant Smith scrubber remain very flexible. This scrubber would offer the same benefits as the scrubbers previously discussed for Plants Crist and Daniel.

Plant Smith Unit 2 Baghouse

The Plant Smith Unit 2 baghouse project has been included in the Gulf Power Environmental compliance plan because potential mercury regulation will likely lead to additional controls being required for Plant Smith. The baghouse project is currently planned for operation in 2018. The schedule and decisions about the Plant Smith Unit 2 baghouse remain very flexible.

4.3.2 Plant Smith Comparison of Retrofit versus Retirement and Replacement

Gulf's March 2007 CAIR/CAMR/CAVR compliance plan included results of an economic analysis that was performed to assess the costs over a period from 2006 until the current planned retirement date for the two coal-fired Plant Smith units. The costs of operating the retrofitted units and its affect on system dispatch costs and the need to purchase allowances to meet any remaining emission limits (all of which are characterized as "incremental costs") were compared to the cost of a generic peaking unit and associated energy costs. The results of the analysis indicated there was a savings associated with retrofitting and continuing to operate each generating unit at Plant Smith, as opposed to replacing the generation.

The Plant Smith economic analysis has not been updated because Gulf has not made any changes to the Plant Smith compliance strategy, other than delaying completion of the mercury monitor installation. In addition, the majority of the expenditures for Phase I environmental projects at Plant Smith were incurred prior to 2009. An updated analysis will be performed before Gulf moves forward with the Plant Smith scrubber and baghouse projects. Both of these projects are included in Phase II of Gulf's compliance plan which has not yet been approved for ECRC recovery.

4.3.3 Plant Smith Emission Monitoring Requirements

CAIR required the installation of a parametric emission monitoring system on the Plant Smith combustion turbine during 2007. Gulf will continue to incur future maintenance expenses to ensure accurate accounting of emissions. In response to the CAMR vacatur, Gulf has delayed further mercury monitoring capital costs until at least 2010.

4.3.4 Conclusions for Plant Smith

The retrofit of Smith Units 1 and 2 with SNCR, a flue gas desulfurization scrubber, and a baghouse are the best options for compliance with CAIR, CAVR, and potential mercury regulation at Plant Smith. These technologies offer the necessary emission reductions for SO_2 and NO_X. The Smith Unit 2 SNCR was placed in-service in the fall of 2008 and the Smith Unit 1 SNCR will be placed in-service during the spring of 2009. The Plant Smith mercury monitoring project has been delayed until at least 2010. The schedule and decisions regarding the Plant Smith scrubber and baghouse, Phase II projects, remain very flexible. These projects are included in Gulf's compliance plan for future review and approval.

Fuel switching will not reduce emissions to the required level. Allowance purchases are too uncertain and risky as a sole compliance option, especially for annual NO_X. Retirement and replacement of the units is not economic relative to retrofit of the existing units. The scrubber may also be required as part of the CAVR "reasonable progress program."

4.4 Plant Scholz

Plant Scholz consists of two coal-fired electric generating units that each have a nameplate rating of 49 MW. The facility is located in Jackson County, Florida. Both units were affected under the Acid Rain Program, and the plant has operated on low-sulfur coals since the 1990s to lower SO_2 emissions. Because these units are small and older, NO_X averaging was used to achieve compliance with the NO_X requirements under the Acid Rain Program without the installation of emission control equipment.

For CAIR and CAVR requirements at Plant Scholz, a thorough assessment was conducted to compare retrofit controls versus retirement and replacement options for compliance. As noted under Section 3.2, fuel switching and exclusive reliance on allowance purchases were eliminated as viable options for Gulf Power. Because this small plant is nearing retirement, significant investments in capital equipment to reduce emissions cannot be justified economically. The plant will utilize Company-wide allowance trading options to comply up until the Scholz units are retired, repowered, or replaced.

4.4.1 Plant Scholz Emission Monitoring Requirements

The Scholz mercury emission monitoring system was being installed during February of 2008 when the court issued an opinion vacating the CAMR. Gulf completed the Scholz installation but postponed certification of the system due to pending regulatory uncertainty regarding quality assurance and reference testing protocols required for certification. Gulf's 2009 ECRC budget projection includes general O&M expenses for the Plant Scholz mercury monitor.

4.4.2 Conclusions for Plant Scholz

For CAIR and CAVR requirements at Plant Scholz, a thorough assessment was conducted to compare the various options for compliance. Fuel switching, allowance purchases, and emission control retrofit versus retirement and replacement were all evaluated as options for compliance. The plant will utilize Company-wide allowance trading options to comply until it is retired, repowered, or replaced.

4.5 GULF'S ALLOWANCE PURCHASES

Although the retrofit installations set forth in Gulf's compliance plan significantly reduce emissions, they will not result in Gulf achieving CAIR compliance levels without the purchase of some emission allowances. Thus, Gulf's environmental compliance plan calls for the purchase of allowances. The emission allowances Gulf Power projects it needs to purchase, along with estimated costs, are shown in Table 4.5-1. The purchase of allowances in conjunction with the retrofit projects comprises the most reasonable, cost-effective means for Gulf to meet CAIR and CAVR requirements.

Gulf's SO_2 allowance purchases are intended to address: a) the projected shortfalls in 2009 (Acid Rain Program) and 2010-2013 (CAIR) and b) create a buffer of allowances in the event actual emissions varied materially from projections. At this time, Gulf has a projected SO_2 allowance bank of pre-2010 allowances to be carried forward into 2010, the first year of CAIR compliance for SO_2. Gulf projects a need to purchase CAIR annual and seasonal NOx allowances beginning this year.

Table 4.5-1
Gulf Power Allowance Projection and Costs
(2009-2017)

Annual Emissions in Excess of Allocations

	2009	2010	2011	2012	2013	2014	2015	2016	2017
SO_2	15,178	9,903	7,720	5,038	4,812	0	0	0	0
Seasonal NO_X	2,287	2,016	2,029	1,075	1,032	897	808	732	704
Annual NO_X	4,993	5,439	4,563	3,183	2,622	2,360	1,322	1,045	916

Cost of Emissions in Excess of Allocations ($ in thousands)*

		2009	2010	2011	2012	2013	2014	2015	2016	2017
			A	B	C	D	E	F	G	H
1	SO_2	$8,832	[redacted]							
2	Seasonal NO_X	$1,372								
3	Annual NO_X	$21,176								
4	Total Cost	$31,380								

* Projected cost is at forecasted prices of the spot market in a given year; forecast includes pending transactions and commitments to purchase. No costs for SO_2 are projected beginning in 2010 due to banked SO_2 allowances.

FCR-21 Run

TRADE SECRET

090007 Hearing Exhibit - 00003054

5.0 POTENTIAL NEW ENVIRONMENTAL REGULATIONS

5.1 New 8-Hour Ozone Standard

In 2004-2005, the EPA revoked an ozone standard that was based on one-hour ozone levels and published two sets of final rules for implementation of a new, more stringent ozone standard based on eight-hour average levels. State implementation plans, including new emission control regulations necessary to bring ozone nonattainment areas into attainment, were required for most nonattainment areas by June 2007. In June 2007, EPA again proposed revisions to the current ozone standard.

In March 2008, the EPA finalized its revisions to the eight-hour ozone standard, increasing its stringency. The EPA plans to designate nonattainment areas based on the new standard by 2010, and new nonattainment areas within Gulf Power's service territory are expected.

State implementation plans will be developed for these areas by 2013. These SIPs will prescribe emission control measures designed to bring areas into attainment. Although designation of a number of new nonattainment areas is anticipated, specific designations and any subsequent SIP control measures will be based in part on air quality measurements to be made in the future. The ultimate outcome of this matter cannot be determined at this time and will depend on subsequent legal action and/or future nonattainment designations and regulatory plans. Potential nonattainment counties under the new standard are shown below.

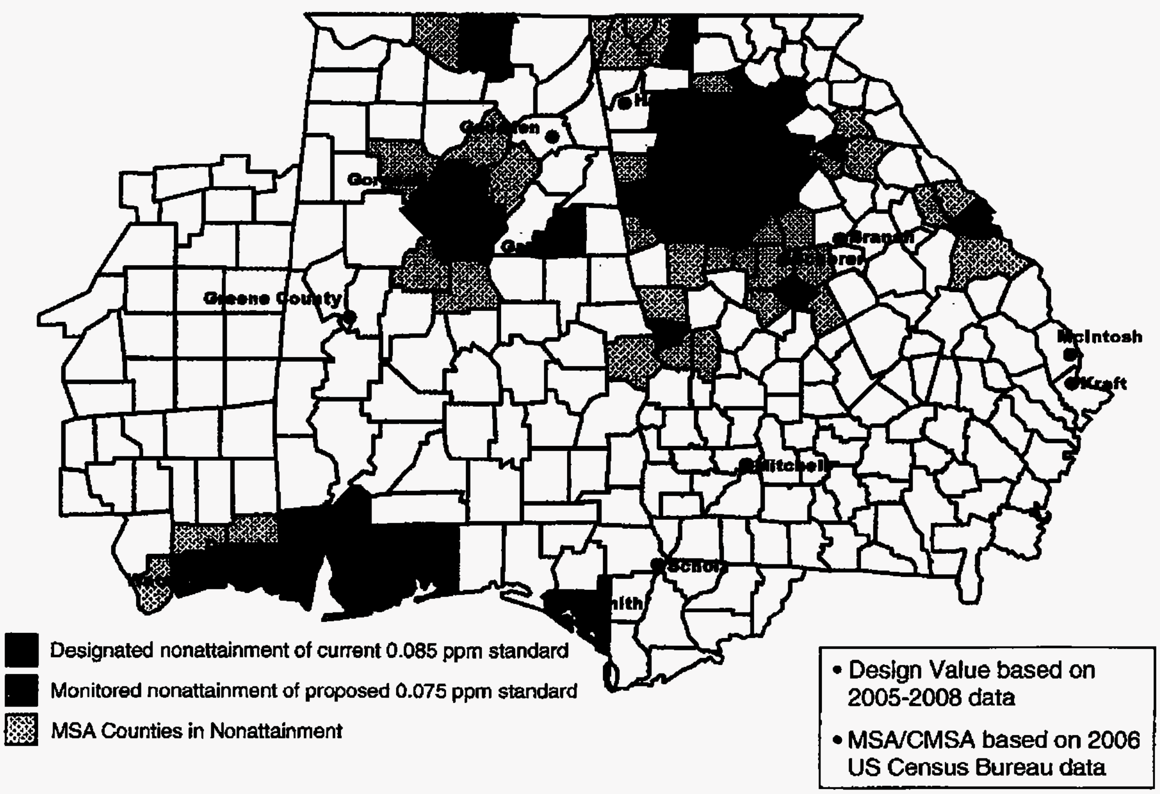

Figure 5.1-1 Potential Ozone Nonattainment Counties

The control strategy for further reducing emissions of ozone will be affected by the strategy implemented for compliance with the CAIR as discussed in Section 2.1.

5.2 New Fine Particulate Standard

During 2005, the EPA's fine particulate matter nonattainment designations became effective for several areas within Southern Company's service area in Alabama and Georgia. State plans for addressing the nonattainment designations under the existing standard were due by April 2008 and could require further reductions in SO_2 and NO_X emissions from power plants. In September 2006, the EPA published a final rule which increased the stringency of the 24-hour fine particulate matter air quality standard. The state-recommended nonattainment areas are shown on the map below; actual EPA designations of areas which fail to meet this newly revised standard were issued in December 2008. The ultimate outcome of this matter depends on the development and submittal of the required state plans and resolution of pending legal challenges and, therefore, cannot be determined at this time.

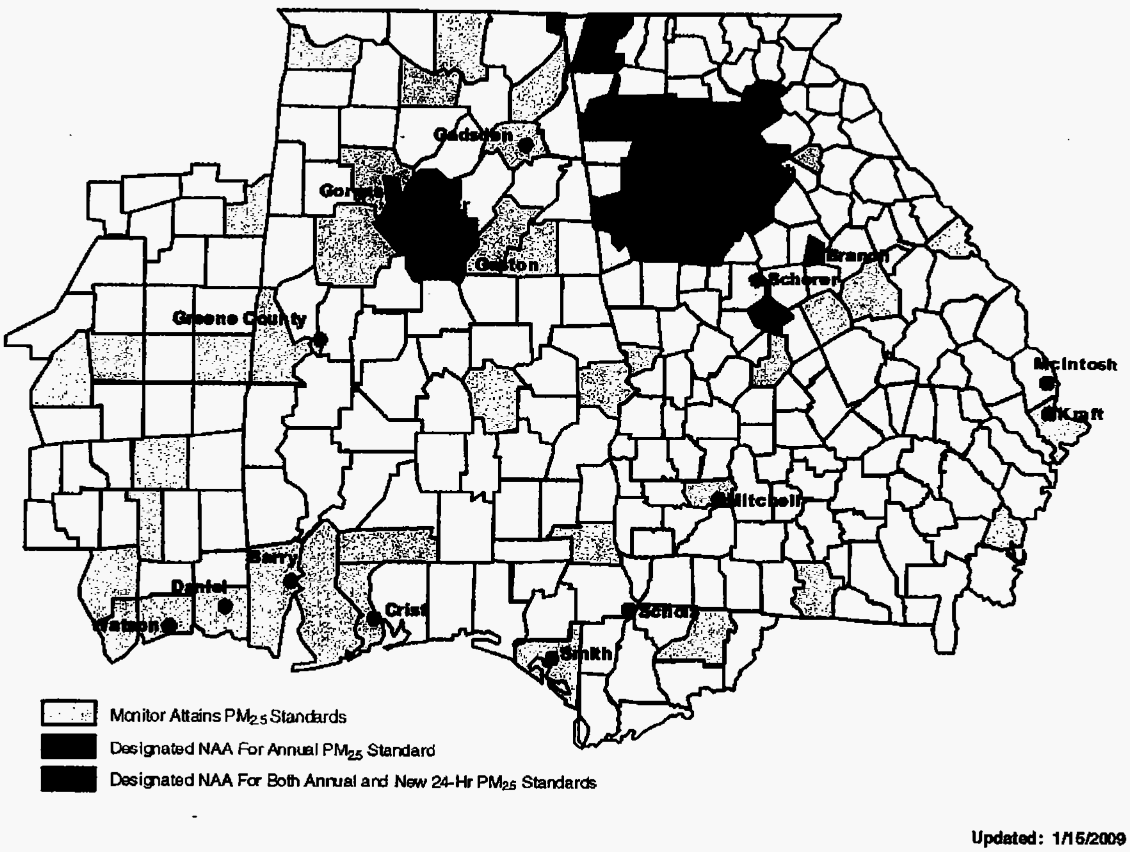

Figure 5.2-1 Nonattainment Areas for Annual PM-2.5 and EPA-Recommended Nonattainment Areas for 24-Hr PM2.5

5.3 Global Climate Issues

Federal legislative proposals that would impose mandatory requirements related to greenhouse gas emissions and renewable energy standards continue to be strongly considered in Congress, and the reduction of greenhouse gas emissions has been identified as a high priority by the current Administration. The ultimate outcome of these proposals cannot be determined at this time; however, mandatory restrictions on the Company's greenhouse gas emissions could result in significant additional compliance costs that could affect future unit retirement and replacement decisions and results of operations, cash flows, and financial condition if such costs are not recovered through regulated rates.

In April 2007, the U.S. Supreme Court ruled that EPA has authority under the Clean Air Act to regulate greenhouse gas emissions from new motor vehicles. The EPA is currently developing its response to this decision. Regulatory decisions that will follow from this response may have implications for both new and existing stationary sources, such as power plants. The ultimate outcome of these rulemaking activities cannot be determined at this time; however, as with the current legislative proposals, mandatory restrictions on the Company's greenhouse gas emissions could result in significant additional compliance costs for electric utilities including Gulf Power.

On June 25, 2008, Florida's Governor signed comprehensive energy-related legislation that includes authorization for the FDEP to adopt rules for a cap-and-trade regulatory program to address greenhouse gas emissions from electric utilities, conditioned upon their ratification by the legislature no sooner than the 2010 legislative session. This legislation also authorizes the Florida PSC to adopt a renewable portfolio standard for public utilities, subject to legislative ratification. The impact of this and any similar legislation on the Company will depend on the future development, adoption, legislative ratification, implementation, and potential legal challenges to rules governing greenhouse gas emissions and mandates regarding the use of renewable energy, and the ultimate outcome cannot be determined at this time.

International climate change negotiations under the United Nations Framework Convention on Climate Change also continue. Current efforts focus on a potential successor to the Kyoto Protocol for the post 2012 timeframe, with a conclusion to this round of negotiations targeted for the end of 2009. The outcome and impact of the international negotiations cannot be determined at this time.

6.0 SUMMARY OF GULF'S COMPLIANCE PLAN

Gulf Power's environmental compliance plan reflects a comprehensive assessment of requirements Gulf and its customers face in meeting CAIR, CAVR and potential mercury, SO_2 and NO_X regulations. CAIR will require significant reductions in SO_2 and NO_X. CAVR may also require the installation of command and control retrofit equipment at certain facilities. In assessing the most cost-effective means of meeting these significant regulatory requirements, Gulf Power considered four primary compliance options: fuel switching, purchase of allowances, retrofit installations, and retirement and replacement of existing units. Fuel switching alone could not meet the requirements of these programs. Given the uncertainty of emerging allowance markets, it was highly questionable whether mature stable allowance markets would emerge in time for an all allowance purchase option to be implemented. There was a fundamental question of whether sufficient allowances would even be available. In addition, given the historic volatility in existing allowance markets, the potential cost of an all-allowance option could be significant. Therefore, risks regarding availability and costs of allowances resulted in an unacceptable level of risk for an all-allowance compliance approach for Gulf and its customers. As a result, Gulf assessed the best means of meeting plant-by-plant emission requirements through retrofit measures supplemented by allowance purchases and compared those options to retiring and replacing existing units. That analysis led to the selection of Gulf Power's environmental compliance plan set forth in Tables 3.1-1 and 3.1-2. Gulf Power's environmental compliance plan, which is based upon analytically sound technical and economic evaluations of alternatives, is the most reasonable, cost effective compliance plan available to Gulf and its customers under current planning assumptions. Gulf Power's environmental compliance plan assures environmental compliance and preserves flexibility for dealing with ever changing requirements and assumptions.

APPENDIX I

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

JANUARY 2008 - DECEMBER 2008
FINAL TRUE-UP

TJK-1
DOCKET NO. 090007-EI
EXHIBIT__________
PAGES 1-64

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 3
COMPANY Florida Power & Light Company (Direct)
WITNESS T. J. Keith (TJK-1)
DATE 11/02/09

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up for the Period
January through December 2008

Line No.				
1	Over/(Under) Recovery for the Current Period (Form 42-2A Page 2 of 2, Line 5)	($3,141,513)		
2	Interest Provision (Form 42-2A Page 2 of 2, Line 6)	$107,061		
3	Total		($3,034,452)	
4	Estimated/Actual Over/(Under) Recovery for the Same Period *	($5,816,598)		
5	Interest Provision	$88,022		
6	Total		($5,728,576)	
7	Net True-Up for the period			$2,694,124

* Per Order No. PSC-08-0775-FOF-EI dated November 24, 2008.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January through December 2008

Line No.		January	February	March	April	May	June
1	ECRC Revenues (net of Revenue Taxes)	$3,100,841	$2,884,144	$2,853,259	$2,956,273	$3,236,589	$3,795,339
2	True-up Provision (Order No. PSC-07-0922-FOF-EI)	81,502	81,502	81,502	81,502	81,502	81,502
3	ECRC Revenues Applicable to Period (Lines 1 + 2)	3,182,343	2,965,646	2,934,761	3,037,775	3,318,091	3,876,841
4	Jurisdictional ECRC Costs						
	a - O&M Activities (Form 42-5A, Line 9)	902,508	428,125	949,072	631,259	771,264	1,437,813
	b - Capital Investment Projects (Form 42-7A, Line 9)	2,157,693	2,202,282	2,254,942	2,312,532	2,396,490	2,496,952
	c - Total Jurisdictional ECRC Costs	3,060,201	2,630,407	3,204,015	2,943,791	3,167,753	3,934,765
5	Over/(Under) Recovery (Line 3 - Line 4c)	122,141	335,239	(269,253)	93,983	150,337	(57,924)
6	Interest Provision (Form 42-3A, Line 10)	14,013	11,142	10,240	9,430	9,196	8,462
7	Prior Periods True-Up to be (Collected)/Refunded in 2008	978,023	1,032,676	1,297,555	957,040	978,952	1,056,983
	a - Deferred True-Up from 2007 (Form 42-1A, Line 7)	3,174,379	3,174,379	3,174,379	3,174,379	3,174,379	3,174,379
8	True-Up Collected /(Refunded) (See Line 2)	(81,502)	(81,502)	(81,502)	(81,502)	(81,502)	(81,502)
9	End of Period True-Up (Lines 5+6+7+7a+8)	4,207,055	4,471,934	4,131,419	4,153,331	4,231,362	4,100,398
10	Adjustments to Period Total True-Up Including Interest						
11	End of Period Total Net True-Up (Lines 9+10)	$4,207,055	$4,471,934	$4,131,419	$4,153,331	$4,231,362	$4,100,398

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Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January through December 2008

Line No.		July	August	September	October	November	December	End of Period Amount
1	ECRC Revenues (net of Revenue Taxes)	$3,795,206	$3,765,541	$3,984,614	$3,533,673	$2,926,814	$2,965,034	$39,797,325
2	True-up Provision (Order No. PSC-07-0922-FOF-EI)	81,502	81,502	81,502	81,502	81,502	81,502	978,023
3	ECRC Revenues Applicable to Period (Lines 1 + 2)	3,876,708	3,847,043	4,066,116	3,615,175	3,008,316	3,046,535	40,775,348
4	Jurisdictional ECRC Costs							
	a - O&M Activities (Form 42-5A, Line 9)	1,499,685	1,209,396	737,612	1,571,289	1,142,260	1,311,562	12,591,845
	b - Capital Investment Projects (Form 42-7A, Line 9)	2,606,964	2,727,077	2,834,991	2,936,623	3,051,530	3,346,941	31,325,017
	c - Total Jurisdictional ECRC Costs	4,106,648	3,936,473	3,572,604	4,507,912	4,193,791	4,658,503	43,916,862
5	Over/(Under) Recovery (Line 3 - Line 4c)	(229,941)	(89,430)	493,512	(892,737)	(1,185,475)	(1,611,968)	(3,141,513)
6	Interest Provision (Form 42-3A, Line 10)	8,037	7,562	11,839	11,752	4,554	834	107,061
7	Prior Periods True-Up to be (Collected)/Refunded in 2008	926,019	622,614	459,244	883,093	(79,394)	(1,341,817)	978,023
	a - Deferred True-Up from 2007 (Form 42-1A, Line 7)	3,174,379	3,174,379	3,174,379	3,174,379	3,174,379	3,174,379	
8	True-Up Collected /(Refunded) (See Line 2)	(81,502)	(81,502)	(81,502)	(81,502)	(81,502)	(81,502)	(978,023)
9	End of Period True-Up (Lines 5+6+7+7a+8)	3,796,993	3,633,623	4,057,472	3,094,985	1,832,562	139,926	(3,034,452)
10	Adjustments to Period Total True-Up Including Interest							
11	End of Period Total Net True-Up (Lines 9+10)	$3,796,993	$3,633,623	$4,057,472	$3,094,985	$1,832,562	$139,926	($3,034,452)

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January through December 2008

Form 42-3A
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)	$4,152,402	$4,207,055	$4,471,934	$4,131,419	$4,153,331	$4,231,362
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	4,193,042	4,460,792	4,121,179	4,143,901	4,222,166	4,091,936
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	$8,345,444	$8,667,847	$8,593,113	$8,275,320	$8,375,497	$8,323,298
4	Average True-Up Amount (Line 3 x 1/2)	$4,172,722	$4,333,923	$4,296,556	$4,137,660	$4,187,748	$4,161,649
5	Interest Rate (First Day of Reporting Month)	4.98000%	3.08000%	3.09000%	2.63000%	2.84000%	2.43000%
6	Interest Rate (First Day of Subsequent Month)	3.08000%	3.09000%	2.63000%	2.84000%	2.43000%	2.45000%
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	8.06000%	6.17000%	5.72000%	5.47000%	5.27000%	4.88000%
8	Average Interest Rate (Line 7 x 1/2)	4.03000%	3.08500%	2.86000%	2.73500%	2.63500%	2.44000%
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.33583%	0.25708%	0.23833%	0.22792%	0.21958%	0.20333%
10	Interest Provision for the Month (Line 4 x Line 9)	$14,013	$11,142	$10,240	$9,430	$9,196	$8,462

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Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January through December 2008

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)	$4,100,398	$3,796,993	$3,633,623	$4,057,472	$3,094,985	$1,832,562	$45,863,535
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	3,788,956	3,626,061	4,045,633	3,083,233	1,828,008	139,092	41,743,999
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	$7,889,354	$7,423,054	$7,679,256	$7,140,705	$4,922,993	$1,971,654	$87,607,534
4	Average True-Up Amount (Line 3 x 1/2)	$3,944,677	$3,711,527	$3,839,628	$3,570,353	$2,461,496	$985,827	$43,803,767
5	Interest Rate (First Day of Reporting Month)	2.45000%	2.44000%	2.45000%	4.95000%	2.95000%	1.49000%	N/A
6	Interest Rate (First Day of Subsequent Month)	2.44000%	2.45000%	4.95000%	2.95000%	1.49000%	0.54000%	N/A
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	4.89000%	4.89000%	7.40000%	7.90000%	4.44000%	2.03000%	N/A
8	Average Interest Rate (Line 7 x 1/2)	2.44500%	2.44500%	3.70000%	3.95000%	2.22000%	1.01500%	N/A
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.20375%	0.20375%	0.30833%	0.32917%	0.18500%	0.08458%	N/A
10	Interest Provision for the Month (Line 4 x Line 9)	$8,037	$7,562	$11,839	$11,752	$4,554	$834	$107,061

Form 42-4A

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-Up Amount for the Period
January 2008 - December 2008

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	$1,575,551	$1,640,982	($65,431)	-4.0%
	3a Continuous Emission Monitoring Systems-O&M	$856,108	$957,685	($101,577)	-10.6%
	4a Clean Closure Equivalency-O&M	$0	$0	$0	0.0%
	5a Maintenance of Stationary Above Ground Fuel	$1,767,431	$1,513,172	$254,259	16.8%
	8a Oil Spill Cleanup/Response Equipment-O&M	$312,361	$276,344	$36,017	13.0%
	8c Oil Spill Cleanup/Response Equipment-Revenue	$0	$0	$0	0.0%
	9 Low-Level Radioactive Waste Access Fees-O&M	$0	$0	$0	0.0%
	13 RCRA Corrective Action-O&M	$51,059	$64,978	($13,919)	-21.4%
	14 NPDES Permit Fees-O&M	$124,394	$124,395	($1)	0.0%
	17a Disposal of Noncontainerized Liquid Waste-O&M	$256,046	$331,803	($75,757)	-22.8%
	19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	$1,040,997	$1,633,506	($592,509)	-36.3%
	19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	$336,533	$342,390	($5,857)	-1.7%
	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	($917,053)	($983,208)	$66,155	-6.7%
	21 St. Lucie Turtle Net	$4,352	$0	$4,352	N/A
	22 Pipeline Integrity Management	$134,307	$414,465	($280,158)	-67.6%
	23 SPCC-Spill Prevention, Control & Countermeasures	$703,158	$754,325	($51,167)	-6.8%
	24 Manatee Reburn	$608,890	$499,997	$108,893	21.8%
	25 Port Everglades ESP	$1,480,329	$1,991,699	($511,370)	-25.7%
	26 UST Replacement/Removal	$0	$0	$0	0.0%
	27 Lowest Quality Water Source	$273,922	$246,103	$27,819	11.3%
	28 CWA 316(b) Phase II Rule	$346,648	$385,137	($38,489)	-10.0%
	29 SCR Consumables	$361,028	$361,930	($902)	-0.2%
	30 HBMP	$25,757	$19,999	$5,758	28.8%
	31 CAIR Compliance	$1,289,179	$1,242,112	$47,067	3.8%
	32 BART	$1,355	$1,355	$0	0.0%
	34 St. Lucie Cooling Water System Inspection & Maintenance	$2,677,907	$4,996,865	($2,318,958)	-46.4%
	35 Martin Plant Drinking Water System Compliance	$0	$0	$0	0.0%
	36 Low Level Radioactive Waste	$887	120,271	($119,384)	-99.3%
2	Total O&M Activities	$12,750,913	$16,376,072	($3,625,159)	-22.1%
3	Recoverable Costs Allocated to Energy	$5,828,201	$6,360,367	($532,166)	-8.4%
4a	Recoverable Costs Allocated to CP Demand	$6,161,831	$8,662,315	($2,500,484)	-28.9%
4b	Recoverable Costs Allocated to GCP Demand	$760,881	$1,353,390	($592,509)	-43.8%

Notes:
Column(1) is the 12-Month Totals on Form 42-5A
Column(2) is the approved estimated/actual amount in accordance with FPSC Order No. PSC-08-0775-FOF-EI.
Column(3) = Column(1) - Column(2)
Column(4) = Column(3) / Column(2)
Totals may not add due to rounding

Form 42-5A
Page 1 of 2

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January 2008 - December 2008

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	$ 196,527	$ (134,689)	$ 196,527	$ 153,613	$ 153,613	$ 153,613	$719,304
	3a	Continuous Emission Monitoring Systems-O&M	233,577	15,515	35,043	39,344	29,578	43,475	396,532
	5a	Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	(6,866)	15,106	353,242	321,824	428,297	256,002	1,367,604
	8a	Oil Spill Cleanup/Response Equipment-O&M	2,599	5,086	39,949	18,131	10,544	51,916	128,226
	13	RCRA Corrective Action-O&M	0	2,000	0	4,645	0	0	6,645
	14	NPDES Permit Fees-O&M	124,400	13,583	0	0	(13,588)	0	124,395
	17a	Disposal of Noncontainerized Liquid Waste-O&M	0	8,782	36,957	28,698	35,532	70,062	180,030
	19a	Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	17,067	4,595	4,238	86,447	24,371	11,508	148,226
	19b	Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	33,400	1,139	22,981	228	16	8,226	65,990
	19c	Substation Pollutant Discharge Prevention & Removal - Costs included in Base Rates	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(280,116)
	20	Wastewater Discharge Elimination &Reuse	0	0	0	0	0	0	0
	NA	Amortization of Gains on Sales of Emissions Allowances	(18,608)	(18,608)	(18,608)	(18,608)	(281,499)	(89,611)	(445,542)
	21	St. Lucie Turtle Net	0	0	0	0	0	0	0
	22	Pipeline Integrity Management	1,267	44,518	27,366	16,283	24,955	(4,924)	109,465
	23	SPCC - Spill Prevention, Control & Countermeasures	3,073	6,039	7,649	15,094	11,967	38,967	82,791
	24	Manatee Reburn	1,336	19,999	31,432	85,777	62,320	94,222	295,086
	25	Pt. Everglades ESP Technology	98,999	116,552	72,030	60,451	112,346	117,013	577,390
	26	UST Replacement/Removal	0	0	0	0	0	0	0
	27	Lowest Quality Water Source	21,167	21,725	20,835	21,637	21,182	22,601	129,147
	28	CWA 316(b) Phase II Rule	32,338	49,927	30,405	(162,519)	44,946	103,277	98,374
	29	SCR Consumables	38,128	22,404	33,637	36,950	32,225	24,533	187,877
	30	HBMP	0	1,482	2,245	1,482	1,482	1,482	8,172
	31	CAIR Compliance	180,550	256,769	104,509	22,045	41,257	61,092	666,221
	32	BART	0	0	832	0	522	0	1,355
	34	St. Lucie Cooling Water System Inspection & Maintenance	2,977	28,922	7,605	(45,674)	85,740	522,093	601,662
	35	Martin Plant Drinking Water System Compliance	0	0	0	0	0	0	0
	36	Low Level Wast Facility	0	0	0	0	2,165	18,107	20,271
2		Total of O&M Activities	$ 915,246	$ 434,260	$ 962,189	$ 639,161	$ 781,284	$ 1,456,964	$ 5,189,104
3		Recoverable Costs Allocated to Energy	$ 733,882	$ 290,202	$ 532,281	$ 424,622	$ 194,810	$ 526,544	$ 2,702,340
4a		Recoverable Costs Allocated to CP Demand	$ 187,640	$ 162,807	$ 449,013	$ 151,435	$ 585,447	$ 942,255	$ 2,478,597
4b		Recoverable Costs Allocated to GCP Demand	$ (6,276)	$ (18,748)	$ (19,105)	$ 63,104	$ 1,028	$ (11,835)	$ 8,168
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)	$ 723,470	$ 286,084	$ 524,729	$ 418,597	$ 192,046	$ 519,073	$ 2,663,999
8a		Jurisdictional CP Demand Recoverable Costs (B)	$ 185,314	$ 160,789	$ 443,448	$ 149,558	$ 578,190	$ 930,575	$ 2,447,874
8b		Jurisdictional GCP Demand Recoverable Costs (C)	$ (6,276)	$ (18,748)	$ (19,105)	$ 63,104	$ 1,028	$ (11,835)	$ 8,168
9		Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 902,508	$ 428,125	$ 949,072	$ 631,259	$ 771,264	$ 1,437,813	$ 5,120,041

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 2008 - December 2008

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	$ 153,613	$ 153,613	$ 166,298	$ 153,613	$ 114,556	$ 114,556	$856,247	$1,575,551			$1,575,551
3a	Continuous Emission Monitoring Systems-O&M	274,562	33,134	29,043	56,089	32,125	34,622	459,576	856,108			856,108
5a	Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	105,736	69,804	66,075	6,105	82,155	69,951	399,827	1,767,431	1,767,431		
8a	Oil Spill Cleanup/Response Equipment-O&M	22,839	19,720	15,836	19,343	40,265	66,133	184,135	312,361			312,361
13	RCRA Corrective Action-O&M	38,008	8,555	(2,149)	0	0	0	44,414	51,059	51,059		
14	NPDES Permit Fees-O&M	(0)	(0)	(1)	0	0	(0)	(1)	124,394	124,394		
17a	Disposal of Noncontainerized Liquid Waste-O&M	8,907	0	8,838	5,794	18,939	33,539	76,016	256,046			256,046
19a	Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	198,837	48,764	81,432	90,698	150,336	322,704	892,771	1,040,997		1,040,997	
19b	Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	163,452	10,862	7,642	19,201	69,871	(465)	270,543	336,533	310,646		25,887
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	(89,406)	(76,421)	(76,421)	(76,421)	(76,421)	(76,421)	(471,512)	(917,053)			(917,053)
21	St. Lucie Turtle Net	0	0	4,352	0	0	0	4,352	4,352	4,352		
22	Pipeline Integrity Management	19,780	882	797	0	950	2,432	24,842	134,307	134,307		
23	SPCC - Spill Prevention, Control & Countermeasures	103,094	100,206	79,808	122,370	147,616	67,275	620,367	703,158	703,158		
24	Manatee Reburn	19,215	35,227	31,277	29,156	54,655	144,274	313,803	608,890			608,890
25	Pt. Everglades ESP Technology	67,760	89,588	93,310	111,692	335,082	205,507	902,939	1,480,329			1,480,329
26	UST Replacement/Removal	0	0	0	0	0	0	0	0	0		
27	Lowest Quality Water Source	22,336	31,200	15,313	25,759	26,072	24,094	144,775	273,922	273,922		
28	CWA 316(b) Phase II Rule	47,608	87,986	27,263	44,281	16,719	24,418	248,274	346,648	346,648		
29	SCR Consumables	35,989	24,027	23,717	41,262	16,126	32,032	173,152	361,028			361,028
30	HBMP	1,482	9,232	1,482	2,277	1,556	1,556	17,585	25,757	25,757		
31	CAIR Compliance	76,590	40,536	14,787	190,686	71,570	228,590	622,959	1,289,179			1,289,179
32	BART	0	0	0	0	0	0	0	1,355			1,355
34	St. Lucie Cooling Water System Inspection & Maintenance	291,989	583,877	226,115	796,803	100,755	76,705	2,076,244	2,677,907	2,677,907		
35	Martin Plant Drinking Water System Compliance	0	0	0	0	0	0	0	0	0		
36	Low Level Waste Facility	1,657	729	(21,433)	(1,095)	(130)	887	(19,384)	887	819		68
2	Total of O&M Activities	$1,517,359	$1,224,835	$ 746,691	$1,591,129	$1,156,111	$1,325,684	$ 7,561,809	$12,750,913	$ 6,161,831	$ 760,881	$ 5,828,201
3	Recoverable Costs Allocated to Energy	$ 580,972	$ 318,519	$ 303,826	$ 531,012	$ 610,465	$ 781,067	$ 3,125,862	$ 5,828,201			
4a	Recoverable Costs Allocated to CP Demand	$ 760,893	$ 880,894	$ 384,777	$ 992,762	$ 418,653	$ 245,256	$ 3,683,234	$ 6,161,831			
4b	Recoverable Costs Allocated to GCP Demand	$ 175,494	$ 25,421	$ 58,089	$ 67,355	$ 126,993	$ 299,361	$ 752,713	$ 760,881			
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)	$ 572,730	$ 314,000	$ 299,516	$ 523,478	$ 601,804	$ 769,985	$ 3,081,513	$ 5,745,512			
8a	Jurisdictional CP Demand Recoverable Costs (B)	$ 751,461	$ 869,975	$ 380,007	$ 980,456	$ 413,463	$ 242,216	$ 3,637,578	$ 6,085,452			
8b	Jurisdictional GCP Demand Recoverable Costs (C)	$ 175,494	$ 25,421	$ 58,089	$ 67,355	$ 126,993	$ 299,361	$ 752,713	$ 760,881			
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,499,685	$1,209,396	$ 737,612	$1,571,289	$1,142,260	$1,311,562	$ 7,471,804	$12,591,845			

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 2008 - December 2008

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	$ 848,055	$ 847,926	$ 129	0.0%
3b	Continuous Emission Monitoring Systems-Capital	1,020,123	1,055,168	(35,045)	-3.3%
4b	Clean Closure Equivalency-Capital	3,840	3,840	0	0.0%
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	1,700,054	1,702,928	(2,874)	-0.2%
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	1,559	1,560	(1)	-0.1%
8b	Oil Spill Cleanup/Response Equipment-Capital	86,946	89,905	(2,959)	-3.3%
10	Relocate Storm Water Runoff-Capital	9,560	9,560	0	0.0%
NA	SO2 Allowances-Negative Return on Investment	(280,744)	(279,207)	(1,537)	0.6%
12	Scherer Discharge Pipeline-Capital	62,797	62,796	1	0.0%
17b	Disposal of Noncontainerized Liquid Wate-Capital	0	0	0	N/A
20	Wastewater Discharge Elimination & Reuse	240,965	240,966	(1)	0.0%
21	St. Lucie Turtle Net	119,535	120,632	(1,097)	-0.9%
22	Pipeline Integrity Management	0	0	0	0.0%
23	SPCC-Spill Prevention, Control & Countermeasures	2,132,293	2,122,237	10,056	0.5%
24	Manatee Reburn	4,770,685	4,770,684	1	0.0%
25	Pt. Everglades ESP Technology	11,548,344	11,569,509	(21,165)	-0.2%
26	UST Replacement/Removal	66,965	66,966	(1)	0.0%
31	CAIR Compliance	7,871,095	8,105,619	(234,524)	-2.9%
33	CAMR Compliance	1,471,871	1,569,371	(97,500)	-6.2%
34	St. Lucie Cooling Water System Inspection & Maintenance	0	0	0	0.0%
35	Martin Plant Drinking Water System Compliance	0	9,930	(9,930)	-100.0%
36	Low Level Radioactive Waste	0	0	0	0.0%
37	DeSoto Next Generation Solar Energy Center	12,546	29,115	(16,569)	-56.9%
38	Space Coast Next Generation Solar Energy Center	32,419	4,681	27,738	592.6%
39	Martin Next Generation Solar Energy Center	33,697	81,892	(48,195)	-58.9%
2	Total Investment Projects-Recoverable Costs	$ 31,752,606	$ 32,186,076	$ (433,470)	-1.3%
3	Recoverable Costs Allocated to Energy	$ 18,971,552	$ 19,058,076	$ (86,524)	-0.5%
4	Recoverable Costs Allocated to Demand	$ 12,781,054	$ 13,127,999	$ (346,945)	-2.6%

Notes:
Column(1) is the 12-Month Totals on Form 42-7A
Column(2) is the approved estimated/actual amount in accordance with FPSC Order No. PSC-08-0775-FOF-EI.
Column(3) = Column(1) - Column(2)
Column(4) = Column(3) / Column(2)

Totals not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January 2008 - December 2008

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	$ 72,973	$ 72,559	$ 72,144	$ 71,730	$ 71,315	$ 70,869	$ 431,591
3b Continuous Emission Monitoring Systems-Capital	85,034	85,202	87,449	89,367	89,237	89,210	525,499
4b Clean Closure Equivalency-Capital	326	325	324	323	322	321	1,938
5b Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	143,912	143,504	143,097	142,690	142,282	141,875	857,359
7 Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	131	131	131	131	130	130	785
8b Oil Spill Cleanup/Response Equipment-Capital	7,094	7,123	7,051	7,007	6,963	7,039	42,277
10 Relocate Storm Water Runoff-Capital	804	802	801	800	799	797	4,803
NA SO2 Allowances-Negative Return on Investment	(21,695)	(21,523)	(21,351)	(21,179)	(23,954)	(26,562)	(136,266)
12 Scherer Discharge Pipeline-Capital	5,291	5,280	5,270	5,259	5,249	5,238	31,588
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	7,629	7,620	9,556	11,509	51,599
22 Pipeline Integrity Management	0	0	0	0	0	0	0
23 SPCC - Spill Prevention, Control & Countermeasures	173,891	173,504	173,119	172,733	172,346	171,959	1,037,552
24 Manatee Reburn	403,697	402,581	401,464	400,348	399,232	398,115	2,405,438
25 Pt. Everglades ESP Technology	973,786	972,153	971,222	970,480	969,187	966,759	5,823,586
26 UST Removal / Replacement	5,637	5,627	5,616	5,606	5,596	5,586	33,668
31 CAIR Compliance	257,519	303,271	343,703	389,502	470,279	567,643	2,331,917
33 CAMR Compliance	51,304	54,357	68,227	81,835	90,759	100,568	447,049
35 Martin Plant Drinking Water System Compliance	0	0	0	0	0	0	0
36 Low Level Radioactive Waste	0	0	0	0	0	0	0
37 De Soto Solar Project	0	0	0	0	0	0	0
38 Space coast Solar Project	0	0	0	0	0	0	0
39 Martin Solar Project	0	0	0	0	0	0	0
2 Total Investment Projects - Recoverable Costs	$ 2,187,615	$ 2,232,766	$ 2,286,095	$ 2,344,415	$ 2,429,428	$ 2,531,154	$ 14,011,473
3 Recoverable Costs Allocated to Energy	$ 1,565,627	$ 1,566,494	$ 1,570,557	$ 1,574,874	$ 1,576,125	$ 1,577,835	$ 9,431,511
4 Recoverable Costs Allocated to Demand	$ 621,988	$ 666,272	$ 715,538	$ 769,541	$ 853,303	$ 953,319	$ 4,579,961
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)	$ 1,543,414	$ 1,544,269	$ 1,548,274	$ 1,552,530	$ 1,553,763	$ 1,555,449	$ 9,297,699
8 Jurisdictional Demand Recoverable Costs (C)	$ 614,279	$ 658,013	$ 706,668	$ 760,002	$ 842,726	$ 941,503	$ 4,523,191
9 Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 2,157,693	$ 2,202,282	$ 2,254,942	$ 2,312,532	$ 2,396,489	$ 2,496,952	$ 13,820,890

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 2008 - December 2008

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	$ 70,424	$ 70,010	$ 69,596	$ 69,182	$ 68,768	$ 68,484	$ 416,464	$ 848,055		$ 848,055
3b Continuous Emission Monitoring Systems-Capital	85,729	82,561	81,874	81,712	81,522	81,225	494,624	1,020,123		1,020,123
4b Clean Closure Equivalency-Capital	319	318	317	316	315	314	1,902	3,840	3,545	295
5b Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	141,468	141,060	140,653	140,245	139,838	139,431	842,695	1,700,054	1,569,281	130,773
7 Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	130	129	129	129	129	128	774	1,559	1,439	120
8b Oil Spill Cleanup/Response Equipment-Capital	7,115	7,069	7,340	7,760	7,863	7,522	44,669	86,946	80,258	6,688
10 Relocate Storm Water Runoff-Capital	796	795	793	792	791	790	4,757	9,560	8,824	736
NA SO2 Allowances-Negative Return on Investment	(25,897)	(25,130)	(24,423)	(23,716)	(23,010)	(22,303)	(144,478)	(280,744)		(280,744)
12 Scherer Discharge Pipeline-Capital	5,228	5,217	5,207	5,196	5,186	5,175	31,209	62,797	57,966	4,831
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	119,875	240,965	222,429	18,536
21 St. Lucie Turtle Net	11,520	11,518	11,513	11,512	11,514	10,359	67,936	119,535	110,340	9,195
22 Pipeline Integrity Management	0	0	0	0	0	0	0	0	0	0
23 SPCC - Spill Prevention, Control & Countermeasures	171,572	175,421	179,509	181,173	182,911	204,156	1,094,742	2,132,293	1,968,271	164,022
24 Manatee Reburn	396,999	395,883	394,766	393,650	392,533	391,417	2,365,247	4,770,685		4,770,685
25 Pt. Everglades ESP Technology	964,087	961,191	955,962	950,389	947,840	945,290	5,724,758	11,548,344		11,548,344
26 UST Removal / Replacement	5,575	5,565	5,555	5,545	5,534	5,524	33,298	66,965	61,814	5,151
31 CAIR Compliance	676,027	791,352	883,552	968,892	1,063,176	1,156,178	5,539,177	7,871,095	7,265,626	605,469
33 CAMR Compliance	111,396	121,187	141,110	163,621	187,882	299,626	1,024,822	1,471,871	1,358,650	113,221
35 Martin Plant Drinking Water System Compliance	0	0	0	0	0	0	0	0	0	0
36 Low Level Radioactive Waste	0	0	0	0	0	0	0	0	0	0
37 De Soto Solar Project	0	0	0	0	0	12,546	12,546	12,546	11,581	965
38 Space Coast Solar Project	0	0	0	0	0	32,419	32,419	32,419	29,925	2,494
39 Martin Solar Project	0	0	0	0	0	33,697	33,697	33,697	31,105	2,592
2 Total Investment Projects - Recoverable Costs	$2,642,551	$2,764,177	$2,873,450	$2,976,360	$3,092,720	$3,391,875	$17,741,133	$ 31,752,606	$12,781,054	$18,971,552
3 Recoverable Costs Allocated to Energy	$1,579,896	$1,582,950	$1,585,135	$1,586,997	$1,592,659	$1,612,403	$ 9,540,040	$ 18,971,552		
4 Recoverable Costs Allocated to Demand	$1,062,655	$1,181,227	$1,288,315	$1,389,363	$1,500,062	$1,779,472	$ 8,201,093	$ 12,781,054		
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)	$1,557,481	$1,560,491	$1,562,645	$1,564,481	$1,570,062	$1,589,526	$ 9,404,686	$ 18,702,385		
8 Jurisdictional Demand Recoverable Costs (C)	$1,049,483	$1,166,586	$1,272,346	$1,372,142	$1,481,468	$1,757,415	$ 8,099,440	$ 12,622,631		
9 Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$2,606,964	$2,727,077	$2,834,991	$2,936,623	$3,051,530	$3,346,941	$17,504,126	$ 31,325,017		

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 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 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	($11,342)	($11,342)
	c. Retirements		$0	$0	$0	$0	$0	($11,342)	($11,342)
	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	17,462,051	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	14,663,568	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
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	$2,798,483	n/a
6.	Average Net Investment		3,044,925	3,000,112	2,955,298	2,910,485	2,865,671	2,820,874	n/a
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	44,762	$268,849
	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	$70,869	$431,591

Notes:

(A) N/A
(B) 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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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 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	($140,868)	($152,210)
	c. Retirements		$0	$0	$0	$0	$0	($191,631)	($202,973)
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$17,462,051	17,462,051	17,462,051	17,462,051	17,462,051	17,462,051	17,321,183	n/a
3.	Less: Accumulated Depreciation (C)	$14,663,568	14,708,318	14,753,068	14,797,818	14,842,569	14,887,319	14,740,333	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$2,798,483	$2,753,733	$2,708,982	$2,664,232	$2,619,482	$2,574,732	$2,580,850	n/a
6.	Average Net Investment		2,776,108	2,731,358	2,686,607	2,641,857	2,597,107	2,577,791	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		21,332	20,968	20,644	20,300	19,957	19,808	258,251
	b. Debt Component (Line 6 x 1.8767% x 1/12)		4,342	4,272	4,202	4,132	4,062	4,031	52,560
8.	Investment Expenses								
	a. Depreciation (E)		44,750	44,750	44,750	44,750	44,750	44,644	537,244
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$70,424	$70,010	$69,596	$69,182	$68,768	$68,484	$848,055

Notes:

(A) N/A
(B) 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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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: 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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$943	($235,355)	$165,941	$809	$4,880	$19,642	($43,140)
	c. Retirements		($30,957)	($332,083)	($279,786)	$0	($33,307)	$0	($676,133)
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$12,474,967	12,475,910	12,240,554	12,406,495	12,407,304	12,412,184	12,431,827	n/a
3.	Less: Accumulated Depreciation (C)	$6,950,870	6,953,869	6,655,629	6,409,738	6,443,800	6,444,560	6,478,648	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$5,524,097	$5,522,041	$5,584,925	$5,996,758	$5,963,504	$5,967,624	$5,953,178	n/a
6.	Average Net Investment		5,523,069	5,553,483	5,790,841	5,980,131	5,965,564	5,960,401	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		42,440	42,674	44,498	45,952	45,840	45,801	$267,205
	b. Debt Component (Line 6 x 1.8767% x 1/12)		8,638	8,685	9,056	9,352	9,330	9,321	$54,382
8.	Investment Expenses								
	a. Depreciation (E)		33,956	33,843	33,895	34,062	34,067	34,088	$203,911
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$85,034	$85,202	$87,449	$89,367	$89,237	$89,210	$525,499

Notes:
(A) N/A
(B) 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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(G) N/A

Totals may not add due to rounding.

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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 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		($516,453)	($58,192)	$4,346	$6,343	($1,999)	$1,828	($607,268)
	c. Retirements		(87,220.34)	$0	$0	($17,850)	$0	$0	($781,204)
	d. Other (A)		93,425.96	-	-	-	-	-	
2.	Plant-In-Service/Depreciation Base (B)	$12,431,827	11,915,374	11,857,181	11,861,528	11,867,870	11,865,871	11,867,699	n/a
3.	Less: Accumulated Depreciation (C)	$6,478,648	6,518,098	6,551,167	6,584,103	6,599,200	6,632,158	6,665,126	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$5,953,178	$5,397,276	$5,306,015	$5,277,425	$5,268,671	$5,233,712	$5,202,573	n/a
6.	Average Net Investment		5,675,227	5,351,645	5,291,720	5,273,048	5,251,191	5,218,143	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		43,609	41,123	40,662	40,519	40,351	40,097	513,567
	b. Debt Component (Line 6 x 1.8767% x 1/12)		8,875	8,369	8,276	8,247	8,212	8,161	104,522
8.	Investment Expenses								
	a. Depreciation (E)		33,244	33,069	32,936	32,947	32,959	32,967	402,033
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$85,729	$82,561	$81,874	$81,712	$81,522	$81,225	$1,020,123

Notes:
(A) Reserve Transfer
(B) 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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(G) N/A

Totals may not add due to rounding.

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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 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)	$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	35,802	35,913	36,024	36,135	36,246	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$23,285	$23,174	$23,063	$22,953	$22,842	$22,731	$22,620	n/a
6.	Average Net Investment		23,230	23,119	23,008	22,897	22,786	22,676	n/a
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	$1,938

Notes:
(A) N/A
(B) 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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(G) N/A

Totals may not add due to rounding.

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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 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)	$58,866	58,866	58,866	58,866	58,866	58,866	58,866	n/a
3.	Less: Accumulated Depreciation (C)	$36,246	36,356	36,467	36,578	36,689	36,800	36,910	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$22,620	$22,509	$22,399	$22,288	$22,177	$22,066	$21,955	n/a
6.	Average Net Investment		22,565	22,454	22,343	22,232	22,122	22,011	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		173	173	172	171	170	169	2,066
	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 42-8A, pages 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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 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)	$13,550,217	13,550,217	13,550,217	13,550,217	13,550,217	13,550,217	13,550,217	n/a
3.	Less: Accumulated Depreciation (C)	$2,729,709	2,773,756	2,817,802	2,861,849	2,905,895	2,949,942	2,993,988	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$10,820,508	$10,776,462	$10,732,415	$10,688,369	$10,644,322	$10,600,276	$10,556,229	n/a
6.	Average Net Investment		10,798,485	10,754,438	10,710,392	10,666,346	10,622,299	10,578,253	n/a
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	16,543	$100,293
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	$857,359

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s),, or plant account(s). See Form 42-8A, pages 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(G) N/A

Totals may not add due to rounding.

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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 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)	$13,550,217	13,550,217	13,550,217	13,550,217	13,550,217	13,550,217	13,550,217	n/a
3.	Less: Accumulated Depreciation (C)	$2,993,988	3,038,035	3,082,081	3,126,128	3,170,174	3,214,220	3,258,267	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$10,556,229	$10,512,183	$10,468,136	$10,424,090	$10,380,043	$10,335,997	$10,291,951	n/a
6.	Average Net Investment		10,534,206	10,490,160	10,446,113	10,402,067	10,358,020	10,313,974	n/a
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)		16,474	16,406	16,337	16,268	16,199	16,130	196,107
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	$140,245	$139,838	$139,431	$1,700,054

Notes:
(A) N/A
(B) 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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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		$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)	$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	20,247	20,278	20,309	20,340	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$10,876	$10,845	$10,814	$10,783	$10,752	$10,721	$10,690	n/a
6.	Average Net Investment		10,860	10,829	10,798	10,767	10,736	10,705	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		83	83	83	83	83	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	$785

Notes:

(A) N/A
(B) 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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(G) N/A

Totals may not add due to rounding.

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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 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)	$31,030	31,030	31,030	31,030	31,030	31,030	31,030	n/a
3.	Less: Accumulated Depreciation (C)	$20,340	20,371	20,402	20,433	20,464	20,495	20,526	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$10,690	$10,659	$10,628	$10,597	$10,566	$10,535	$10,504	n/a
6.	Average Net Investment		10,674	10,643	10,612	10,581	10,550	10,519	n/a
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	$1,559

Notes:
(A) N/A
(B) 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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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 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	$2,112	$0	($0)	$0	$9,270	$11,382
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$414,605	414,605	416,717	416,717	416,717	416,717	425,987	n/a
3.	Less: Accumulated Depreciation (C)	$154,046	158,752	163,520	168,251	172,983	177,714	182,522	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$260,559	$255,853	$253,196	$248,465	$243,734	$239,003	$243,465	n/a
6.	Average Net Investment		258,206	254,525	250,831	246,100	241,369	241,234	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		1,984	1,956	1,927	1,891	1,855	1,854	$11,467
	b. Debt Component (Line 6 x 1.8767% x 1/12)		404	398	392	385	377	377	$2,334
8.	Investment Expenses								
	a. Depreciation (E)		4,706	4,769	4,731	4,731	4,731	4,808	$28,476
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$7,094	$7,123	$7,051	$7,007	$6,963	$7,039	$42,277

Notes:
(A) N/A
(B) 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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$1	$3	$29,890	$14,405	$2	($2)	$55,681
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								0
2.	Plant-In-Service/Depreciation Base (B)	$425,987	425,988	425,990	455,880	470,285	470,287	470,285	n/a
3.	Less: Accumulated Depreciation (C)	$182,522	187,408	192,293	197,357	202,684	208,097	213,218	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$243,465	$238,580	$233,697	$258,523	$267,601	$262,190	$257,067	n/a
6.	Average Net Investment		241,022	236,138	246,110	263,062	264,896	259,629	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		1,852	1,815	1,891	2,021	2,036	1,995	23,076
	b. Debt Component (Line 6 x 1.8767% x 1/12)		377	369	385	411	414	406	4,697
8.	Investment Expenses								
	a. Depreciation (E)		4,886	4,886	5,064	5,327	5,413	5,121	59,173
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$7,115	$7,069	$7,340	$7,760	$7,863	$7,522	$86,946

Notes:
(A) N/A
(B) 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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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		$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)	$117,794	117,794	117,794	117,794	117,794	117,794	117,794	n/a
3.	Less: Accumulated Depreciation (C)	$45,687	45,825	45,962	46,100	46,237	46,374	46,512	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$72,107	$71,969	$71,832	$71,694	$71,557	$71,419	$71,282	n/a
6.	Average Net Investment		72,038	71,900	71,763	71,626	71,488	71,351	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		554	552	551	550	549	548	$3,305
	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 42-8A, pages 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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 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)	$117,794	117,794	117,794	117,794	117,794	117,794	117,794	n/a
3.	Less: Accumulated Depreciation (C)	$46,512	46,649	46,787	46,924	47,061	47,199	47,336	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$71,282	$71,145	$71,007	$70,870	$70,732	$70,595	$70,458	n/a
6.	Average Net Investment		71,213	71,076	70,939	70,801	70,664	70,526	n/a
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)		$798	$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 42-8A, pages 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(G) N/A

Totals may not add due to rounding.

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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 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)	$864,260	864,260	864,260	864,260	864,260	864,260	864,260	n/a
3.	Less: Accumulated Depreciation (C)	$414,707	415,845	416,984	418,123	419,262	420,400	421,539	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$449,554	$448,415	$447,276	$446,138	$444,999	$443,860	$442,721	n/a
6.	Average Net Investment		448,984	447,846	446,707	445,568	444,429	443,291	n/a
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	$31,588

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s),, or plant account(s). See Form 42-8A, pages 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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 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)	$864,260	864,260	864,260	864,260	864,260	864,260	864,260	n/a
3.	Less: Accumulated Depreciation (C)	$421,539	422,678	423,817	424,955	426,094	427,233	428,372	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$442,721	$441,583	$440,444	$439,305	$438,166	$437,028	$435,889	n/a
6.	Average Net Investment		442,152	441,013	439,874	438,736	437,597	436,458	n/a
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	8,308
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	$62,797

Notes:
(A) N/A
(B) 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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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. 17b)
(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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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. 17b)
(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	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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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: Wastewater/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		$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)	$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)	$562,996	566,645	570,294	573,943	577,591	581,240	584,889	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,798,665	$1,795,017	$1,791,368	$1,787,719	$1,784,070	$1,780,422	$1,776,773	n/a
6.	Average Net Investment		1,796,841	1,793,192	1,789,544	1,785,895	1,782,246	1,778,597	n/a
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 1.6767% 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 42-8A, pages 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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: Wastewater/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		$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)	$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)	$584,889	588,538	592,186	595,835	599,484	603,132	606,781	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,776,773	$1,773,124	$1,769,476	$1,765,827	$1,762,178	$1,758,529	$1,754,881	n/a
6.	Average Net Investment		1,774,949	1,771,300	1,767,651	1,764,002	1,760,354	1,756,705	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		13,639	13,611	13,583	13,555	13,527	13,499	163,836
	b. Debt Component (Line 6 x 1.8767% x 1/12)		2,776	2,770	2,764	2,759	2,753	2,747	33,344
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	$240,965

Notes:
(A) N/A
(B) 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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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 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	($362,595)	$2,743	($359,851)
	c. Retirements		$0	$0	$0	$0	($828,789)	$0	($828,789)
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$828,789	828,789	828,789	828,789	828,789	466,195	468,938	n/a
3.	Less: Accumulated Depreciation (C)	$105,991	106,958	107,925	108,892	109,859	(718,175)	(717,630)	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$722,798	$721,831	$720,865	$719,898	$718,931	$1,184,370	$1,186,568	n/a
6.	Average Net Investment		722,315	721,348	720,381	719,414	951,650	1,185,469	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		5,550	5,543	5,536	5,528	7,313	9,109	$38,579
	b. Debt Component (Line 6 x 1.8767% x 1/12)		1,130	1,128	1,127	1,125	1,488	1,854	$7,852
8.	Investment Expenses								
	a. Depreciation (E)		967	967	967	967	755	545	$5,169
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$7,647	$7,638	$7,629	$7,620	$9,556	$11,509	$51,599

Notes:
(A) N/A
(B) 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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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: 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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$327	$237	($68)	$772	$578	($221,463)	($579,469)
	c. Retirements		$0	$0	$0	$0	$0	$0	($826,789)
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$468,938	469,265	469,502	469,434	470,206	470,783	249,320	n/a
3.	Less: Accumulated Depreciation (C)	($717,630)	(717,082)	(716,535)	(715,967)	(715,439)	(714,890)	(714,470)	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,186,568	$1,186,348	$1,186,037	$1,185,421	$1,185,645	$1,185,673	$963,790	n/a
6.	Average Net Investment		1,186,458	1,186,193	1,185,729	1,185,533	1,185,659	1,074,732	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		9,117	9,115	9,111	9,110	9,111	8,258	92,401
	b. Debt Component (Line 6 x 1.8767% x 1/12)		1,856	1,855	1,854	1,854	1,854	1,681	18,806
8.	Investment Expenses								
	a. Depreciation (E)		547	548	548	548	549	420	8,328
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$11,520	$11,518	$11,513	$11,512	$11,514	$10,359	$119,535

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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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: 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		$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

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Notes:
(A) N/A
(B) 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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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 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	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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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 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	$231	$0	$0	$0	$231
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$15,849,669	15,849,669	15,849,669	15,849,900	15,849,900	15,849,900	15,849,900	n/a
3.	Less: Accumulated Depreciation (C)	$1,549,691	1,591,528	1,633,366	1,675,203	1,717,041	1,758,879	1,800,716	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$14,299,978	$14,258,141	$14,216,303	$14,174,698	$14,132,859	$14,091,021	$14,049,183	n/a
6.	Average Net Investment		14,279,059	14,237,222	14,195,500	14,153,777	14,111,940	14,070,102	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		109,723	109,401	109,081	108,760	108,439	108,117	$653,520
	b. Debt Component (Line 6 x 1.8767% x 1/12)		22,331	22,266	22,200	22,135	22,070	22,004	$133,006
8.	Investment Expenses								
	a. Depreciation (E)		41,837	41,837	41,838	41,838	41,838	41,838	$251,026
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$173,891	$173,504	$173,119	$172,733	$172,346	$171,959	$1,037,552

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s),, or plant account(s). See Form 42-8A, pages 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$680,610	$38,846	$342,138	$56,605	$3,635,237	$4,753,667
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$15,849,900	15,849,900	16,530,509	16,569,356	16,911,494	16,968,099	20,603,335	n/a
3.	Less: Accumulated Depreciation (C)	$1,800,716	1,842,554	1,885,486	1,929,581	1,973,987	2,018,700	2,068,022	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$14,049,183	$14,007,345	$14,645,023	$14,639,775	$14,937,507	$14,949,399	$18,535,314	n/a
6.	Average Net Investment		14,028,264	14,326,184	14,642,399	14,788,641	14,943,453	16,742,356	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		107,796	110,065	112,515	113,638	114,828	128,651	1,341,032
	b. Debt Component (Line 6 x 1.8767% x 1/12)		21,939	22,405	22,899	23,128	23,370	26,183	272,930
8.	Investment Expenses								
	a. Depreciation (E)		41,838	42,932	44,095	44,406	44,713	49,322	518,331
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$171,572	$175,421	$179,509	$181,173	$182,911	$204,156	$2,132,293

Notes:
(A) N/A
(B) 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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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 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	$22	$0	$22
c. Retirements		$0	$0	$0	$0	$0	$0	$0
d. Other (A)								
2. Plant-In-Service/Depreciation Base (B)	$32,862,547	32,862,547	32,862,547	32,862,547	32,862,547	32,862,568	32,862,568	n/a
3. Less: Accumulated Depreciation (C)	$2,203,935	2,324,657	2,445,380	2,566,103	2,686,825	2,807,548	2,928,271	n/a
4. CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5. Net Investment (Lines 2 - 3 + 4)	$30,658,612	$30,537,889	$30,417,167	$30,296,444	$30,175,721	$30,055,020	$29,934,297	n/a
6. Average Net Investment		30,598,251	30,477,528	30,356,805	30,236,083	30,115,371	29,994,659	n/a
7. Return on Average Net Investment								
a. Equity Component grossed up for taxes (D)		235,122	234,194	233,267	232,339	231,412	230,484	$1,396,818
b. Debt Component (Line 6 x 1.8767% x 1/12)		47,853	47,664	47,475	47,286	47,097	46,909	$284,284
8. Investment Expenses								
a. Depreciation (E)		120,723	120,723	120,723	120,723	120,723	120,723	$724,336
b. Amortization (F)								
c. Dismantlement								
d. Property Expenses								
e. Other (G)								
9. Total System Recoverable Expenses (Lines 7 & 8)		$403,697	$402,581	$401,464	$400,348	$399,232	$398,115	$2,405,438

Notes:

(A) N/A
(B) 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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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 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	$22
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$32,862,568	32,862,568	32,862,568	32,862,568	32,862,568	32,862,568	32,862,568	n/a
3.	Less: Accumulated Depreciation (C)	$2,928,271	3,048,994	3,169,716	3,290,439	3,411,162	3,531,885	3,652,607	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$29,934,297	$29,813,575	$29,692,852	$29,572,129	$29,451,406	$29,330,684	$29,209,961	n/a
6.	Average Net Investment		29,873,936	29,753,213	29,632,491	29,511,768	29,391,045	29,270,322	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		229,556	228,629	227,701	226,773	225,846	224,918	2,760,241
	b. Debt Component (Line 6 x 1.8767% x 1/12)		46,720	46,531	46,342	46,153	45,965	45,776	561,771
8.	Investment Expenses								
	a. Depreciation (E)		120,723	120,723	120,723	120,723	120,723	120,723	1,448,673
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$396,999	$395,883	$394,766	$393,650	$392,533	$391,417	$4,770,685

Notes:
(A) N/A
(B) 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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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 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		$2,868	$153,940	$119,067	$184,499	$28,753	($481)	$488,646
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$80,951,062	80,953,930	81,107,869	81,226,936	81,411,435	81,440,189	81,439,708	n/a
3.	Less: Accumulated Depreciation (C)	$5,768,551	6,048,324	6,328,328	6,608,730	6,889,581	7,170,752	7,451,964	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$75,182,510	$74,905,605	$74,779,542	$74,618,206	$74,521,854	$74,269,437	$73,987,743	n/a
6.	Average Net Investment		75,044,057.76	74,842,573	74,698,874	74,570,030	74,395,645	74,128,590	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		576,651.12	575,103	573,999	573,009	571,669	569,617	$3,440,046
	b. Debt Component (Line 6 x 1.8767% x 1/12)		117,361	117,046	116,822	116,620	116,347	115,930	$700,126
8.	Investment Expenses								
	a. Depreciation (E)		279,773	280,003	280,402	280,851	281,171	281,213	$1,683,413
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$973,785.72	$972,153	$971,222	$970,480	$969,187	$966,759	$5,823,586

Notes:
(A) N/A
(B) 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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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 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		($11,209)	($36,427)	$325	$0	$0	$0	$441,335
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$81,439,708	81,428,498	81,392,072	81,392,396	81,392,396	81,392,396	81,392,396	n/a
3.	Less: Accumulated Depreciation (C)	$7,451,964	7,733,159	8,014,279	8,292,925	8,568,560	8,844,194	9,119,828	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$73,987,743	$73,695,339	$73,377,793	$73,099,471	$72,823,837	$72,548,202	$72,272,568	n/a
6.	Average Net Investment		73,841,541	73,536,566	73,238,632	72,961,654	72,686,019	72,410,385	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		567,411	565,067	562,778	560,650	558,532	556,414	6,810,897
	b. Debt Component (Line 6 x 1.8767% x 1/12)		115,481	115,004	114,538	114,105	113,674	113,243	1,386,170
8.	Investment Expenses								
	a. Depreciation (E)		281,195	281,120	278,646	275,634	275,634	275,634	3,351,277
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$964,087	$961,191	$955,962	$950,389	$947,840	$945,290	$11,548,344

Notes:

(A) N/A
(B) 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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(G) N/A

Totals may not add due to rounding.

<u>Florida Power & Light Company</u>
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
<u>For Project: UST Removal / Replacement (Project No. 26)</u>
(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)	$492,916	492,916	492,916	492,916	492,916	492,916	492,916	n/a
3.	Less: Accumulated Depreciation (C)	$2,773	3,882	4,991	6,100	7,209	8,318	9,427	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$490,144	$489,035	$487,926	$486,817	$485,708	$484,598	$483,489	n/a
6.	Average Net Investment		489,589	488,480	487,371	486,262	485,153	484,044	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,762	3,754	3,745	3,737	3,728	3,719	$22,445
	b. Debt Component (Line 6 x 1.8767% x 1/12)		766	764	762	760	759	757	$4,568
8.	Investment Expenses								
	a. Depreciation (E)		1,109	1,109	1,109	1,109	1,109	1,109	$6,654
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$5,637	$5,627	$5,616	$5,606	$5,596	$5,586	$33,667

Notes:

(A) N/A
(B) 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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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)	$492,916	492,916	492,916	492,916	492,916	492,916	492,916	n/a
3.	Less: Accumulated Depreciation (C)	$9,427	10,536	11,645	12,754	13,863	14,972	16,081	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$483,489	$482,380	$481,271	$480,162	$479,053	$477,944	$476,835	n/a
6.	Average Net Investment		482,935	481,826	480,717	479,608	478,499	477,390	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,711	3,702	3,694	3,685	3,677	3,668	44,583
	b. Debt Component (Line 6 x 1.8767% x 1/12)		755	754	752	750	748	747	9,074
8.	Investment Expenses								
	a. Depreciation (E)		1,109	1,109	1,109	1,109	1,109	1,109	13,309
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$5,575	$5,565	$5,555	$5,545	$5,534	$5,524	$66,965

Notes:
(A) N/A
(B) 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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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: 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		$3,387,815	$6,461,418	$2,644,701	$7,667,808	$9,793,209	$11,256,143	$41,211,094
	b. Clearings to Plant		($1,225)	$217,760	$21,966	$1,695	$5,872	$839	$246,907
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$57,722	56,497	274,258	296,224	297,919	303,791	304,630	n/a
3.	Less: Accumulated Depreciation (C)	$75	222	586	1,188	1,813	2,446	3,085	n/a
4.	CWIP - Non Interest Bearing	$26,078,873	29,466,688	35,710,636	37,920,051	45,587,860	55,381,068	66,637,211	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$26,136,521	$29,522,963	$35,984,308	$38,215,087	$45,863,965	$55,682,413	$66,938,756	n/a
6.	Average Net Investment		27,829,742	32,753,636	37,099,698	42,049,526	50,783,189	61,310,585	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		213,848	251,684	285,080	323,116	390,227	471,121	$1,935,076
	b. Debt Component (Line 6 x 1.8767% x 1/12)		43,523	51,223	58,020	65,761	79,420	95,884	$393,831
8.	Investment Expenses								
	a. Depreciation (E)		148	364	602	625	633	639	$3,010
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$257,519	$303,271	$343,703	$389,502	$470,279	$567,643	$2,331,917

Notes:

(A) N/A
(B) 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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(G) N/A

Totals may not add due to rounding.

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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 Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$11,478,909	$12,935,294	$7,022,837	$11,450,473	$5,326,038	$10,431,057	$99,857,703
	b. Clearings to Plant		$435,331	$236	($13,393)	$1,310	$17,162,833	$661,920	$18,495,144
	c. Retirements		($93,426)	$0	$0	$0	$0	$0	($93,426)
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$304,630	739,961	740,196	726,803	728,113	17,890,946	18,552,866	n/a
3.	Less: Accumulated Depreciation (C)	$3,065	(88,886)	(87,429)	(85,986)	(84,554)	(71,481)	(46,278)	n/a
4.	CWIP - Non Interest Bearing	$66,637,211	78,116,120	91,051,414	98,074,251	109,524,725	98,796,757	109,227,814	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$66,938,756	$78,944,966	$91,879,040	$98,887,041	$110,337,392	$116,759,184	$127,826,958	n/a
6.	Average Net Investment		72,941,861	85,412,003	95,383,040	104,612,217	113,548,288	122,293,071	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		560,497	656,320	732,939	803,858	872,524	939,720	6,500,935
	b. Debt Component (Line 6 x 1.8767% x 1/12)		114,074	133,576	149,170	163,603	177,578	191,254	1,323,086
8.	Investment Expenses								
	a. Depreciation (E)		1,456	1,456	1,443	1,432	13,073	25,203	47,074
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$676,027	$791,352	$883,552	$968,892	$1,063,176	$1,156,178	$7,871,095

Notes:

(A) N/A
(B) 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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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 Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		($844,456)	$1,504,735	$1,494,882	$1,447,972	$482,000	$1,639,243	$5,724,376
	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	$5,969,718	5,125,262	6,629,996	8,124,879	9,572,851	10,054,851	11,694,093	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$5,969,718	$5,125,262	$6,629,996	$8,124,879	$9,572,851	$10,054,851	$11,694,093	n/a
6.	Average Net Investment		5,547,490	5,877,629	7,377,437	8,848,865	9,813,851	10,874,472	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		42,628	45,165	56,689	67,996	75,411	83,561	$371,451
	b. Debt Component (Line 6 x 1.8767% x 1/12)		8,676	9,192	11,538	13,839	15,348	17,007	$75,599
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)		$51,304	$54,357	$68,227	$81,835	$90,759	$100,568	$447,049

Notes:
(A) N/A
(B) 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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(G) N/A

Totals may not add due to rounding.

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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 Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$702,546	$1,414,847	$2,893,607	$1,974,657	$3,272,127	$20,893,768	$36,875,927
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$11,694,093	12,396,640	13,811,486	16,705,093	18,679,750	21,951,877	42,845,645	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$11,694,093	$12,396,640	$13,811,486	$16,705,093	$18,679,750	$21,951,877	$42,845,645	n/a
6.	Average Net Investment		12,045,367	13,104,063	15,258,290	17,692,422	20,315,814	32,398,761	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		92,559	100,694	117,247	135,952	156,110	248,958	1,222,970
	b. Debt Component (Line 6 x 1.8767% x 1/12)		18,838	20,493	23,862	27,669	31,772	50,668	248,902
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)		$111,396	$121,187	$141,110	$163,621	$187,882	$299,626	$1,471,871

Notes:

(A) N/A
(B) 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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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 Water Comp (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 42-8A, pages 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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 Water Comp (Project No. 35)
(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	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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(G) N/A

Totals may not add due to rounding.

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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 Level Rad Waste - LLW (Project No. 36)
(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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(G) N/A

Totals may not add due to rounding.

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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 Level Rad Waste - LLW (Project No. 36)
(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	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 1.6767% 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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Desoto Next Generation Solar Energy Center (Project No. 37)
(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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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: Desoto Next Generation Solar Energy Center (Project No. 37)
(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	$2,713,323	$2,713,323
	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	2,713,323	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$2,713,323	n/a
6.	Average Net Investment		0	0	0	0	0	1,356,661	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	10,425	10,425
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	2,122	2,122
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	$12,546	$12,546

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 42-8A, pages 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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: Space Coast Next Generation Solar Energy Center (Project No. 38)
(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
	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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Space Coast Next Generation Solar Energy Center (Project No. 38)
(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	7,010,918.26	$7,010,918
	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	7,010,918	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$7,010,918	n/a
6.	Average Net Investment		0	0	0	0	0	3,505,459	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	26,937	26,937
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	5,482	5,482
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	$32,419	$32,419

Notes:
(A) N/A
(B) 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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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 Next Generation Solar Energy Center (Project No. 39)
(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
	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 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(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 Next Generation Solar Energy Center (Project No. 39)
(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	$7,287,425	$7,287,425
	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	7,287,425	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$7,287,425	n/a
6.	Average Net Investment		0	0	0	0	0	3,643,712	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	27,999	27,999
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	5,698	5,698
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	$33,697	$33,697

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s),, or plant account(s). See Form 42-8A, pages 49-52
(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 49-52
(F) Applicable amortization period(s). See Form 42-8A, pages 49-52
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2006

Return on Capital Investments, Depreciation and Taxes
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	Six Month 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	(2,355,248)	(2,336,640)	(2,318,032)	(2,299,424)	(2,280,816)	(2,899,518)	(2,844,918)		
2	Total Working Capital	($2,355,248)	($2,336,640)	($2,318,032)	($2,299,424)	($2,280,816)	($2,899,518)	($2,844,918)		
3	Average Net Working Capital Balance		(2,345,944)	(2,327,336)	(2,308,728)	(2,290,120)	(2,590,167)	(2,872,218)		
4	Return on Average Net Working Capital Balance									
a	Equity Component grossed up for taxes (A)		(18,027)	(17,884)	(17,741)	(17,598)	(19,903)	(22,071)		
b	Debt Component (Line 6 x 1.6698% x 1/12)		(3,669)	(3,640)	(3,611)	(3,582)	(4,051)	(4,492)		
5	Total Return Component		($21,695)	($21,523)	($21,351)	($21,179)	($23,954)	($26,562)	($136,266)	(D)
6	Expense Dr (Cr)									
a	411.800 Gains from Dispositions of Allowances		(18,608)	(18,608)	(18,608)	(18,608)	(281,499)	(89,611)		
b	411.900 Losses from Dispositions of Allowances		0	0	0	0	0	0		
c	509.000 Allowance Expense		0	0	0	0	0	0		
7	Net Expense (Lines 6a+6b+6c)		($18,608)	($18,608)	($18,608)	($18,608)	($281,499)	($89,611)	($445,542)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		(40,303)	(40,131)	(39,959)	(39,787)	(305,453)	(116,174)		
a	Recoverable Costs Allocated to Energy		(40,303)	(40,131)	(39,959)	(39,787)	(305,453)	(116,174)		
b	Recoverable Costs Allocated to Demand		0	0	0	0	0	0		
9	Energy Jurisdictional Factor		98.58121%	98.58121%	98.58121%	98.58121%	98.58121%	98.58121%		
10	Demand Jurisdictional Factor		98.76048%	98.76048%	98.76048%	98.76048%	98.76048%	98.76048%		
11	Retail Energy-Related Recoverable Costs (B)		(39,731)	(39,562)	(39,392)	(39,223)	(301,119)	(114,525)		
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0		
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($39,731)	($39,562)	($39,392)	($39,223)	($301,119)	($114,525)		

Notes:

(A) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.2013% reflects an 11% return on equity.
(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule
(E) Line 7 is reported on O&M Schedule

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

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2008

Return on Capital Investments, Depreciation and Taxes
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	Twelve Month 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	($2,844,918)	(2,755,511)	(2,679,090)	(2,602,669)	(2,526,248)	(2,449,827)	(2,373,406)	
2	Total Working Capital	($2,844,918)	($2,755,511)	($2,679,090)	($2,602,669)	($2,526,248)	($2,449,827)	($2,373,406)	
3	Average Net Working Capital Balance		(2,800,215)	(2,717,301)	(2,640,880)	(2,564,459)	(2,488,038)	(2,411,616)	
4	Return on Average Net Working Capital Balance								
a	Equity Component grossed up for taxes (A)		(21,517)	(20,880)	(20,293)	(19,706)	(19,118)	(18,531)	
b	Debt Component (Line 6 x 1.6698% x 1/12)		(4,379)	(4,250)	(4,130)	(4,011)	(3,891)	(3,772)	
5	Total Return Component		($25,897)	($25,130)	($24,423)	($23,716)	($23,010)	($22,303)	($280,744) (D)
6	Expense Dr (Cr)								
a	411.800 Gains from Dispositions of Allowances		(89,406)	(76,421)	(76,421)	(76,421)	(76,421)	(76,421)	
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)		($89,406)	($76,421)	($76,421)	($76,421)	($76,421)	($76,421)	($917,053) (E)
8	Total System Recoverable Expenses (Lines 5+7)		(115,303)	(101,551)	(100,844)	(100,137)	(99,431)	(98,724)	
a	Recoverable Costs Allocated to Energy		(115,303)	(101,551)	(100,844)	(100,137)	(99,431)	(98,724)	
b	Recoverable Costs Allocated to Demand		0	0	0	0	0	0	
9	Energy Jurisdictional Factor		98.58121%	98.58121%	98.58121%	98.58121%	98.58121%	98.58121%	
10	Demand Jurisdictional Factor		98.76048%	98.76048%	98.76048%	98.76048%	98.76048%	98.76048%	
11	Retail Energy-Related Recoverable Costs (B)		(113,667)	(100,110)	(99,413)	(98,717)	(98,020)	(97,323)	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	
13	Tot Applicable beginning of period and end of period depreciable base by production pl		($113,667)	($100,110)	($99,413)	($98,717)	($98,020)	($97,323)	

Notes:

(A) Applicable depreciation rate or rates. See form 42-8A, pages 47-49
(B) Applicable amortization period(s). See Form 42-8A, pages 47-49
(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	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Actual Balance 12/31/07	Actual Balance 12/31/08
02 - Low NOX Burner Technology						
	02 - Steam Generation Plant	PtEverglades U1	31200	6.70%	2,700,574.97	2,689,232.57
	02 - Steam Generation Plant	PtEverglades U2	31200	6.10%	2,368,972.27	2,368,972.27
	02 - Steam Generation Plant	Riviera U3	31200	1.70%	3,815,802.70	3,815,802.70
	02 - Steam Generation Plant	Riviera U4	31200	1.40%	3,246,925.80	3,246,925.80
	02 - Steam Generation Plant	Turkey Pt U1	31200	2.00%	2,925,027.84	2,925,027.84
	02 - Steam Generation Plant	Turkey Pt U2	31200	1.80%	2,416,089.59	2,275,221.65
02 - Low NOX Burner Technology Total					17,473,393.17	17,321,182.83
03 - Continuous Emission Monitoring						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.70%	59,227.10	59,227.10
	02 - Steam Generation Plant	CapeCanaveral Comm	31200	1.30%	26,354.96	44,644.65
	02 - Steam Generation Plant	CapeCanaveral U1	31200	1.40%	494,606.87	325,165.05
	02 - Steam Generation Plant	CapeCanaveral U2	31200	1.10%	511,705.24	345,150.96
	02 - Steam Generation Plant	Cutler Comm	31100	0.00%	64,883.87	64,883.87
	02 - Steam Generation Plant	Cutler Comm	31200	0.50%	36,276.52	36,276.52
	02 - Steam Generation Plant	Cutler U5	31200	0.20%	310,454.41	310,454.41
	02 - Steam Generation Plant	Cutler U6	31200	1.00%	311,861.95	311,861.95
	02 - Steam Generation Plant	Manatee Comm	31200	14.10%	31,859.00	31,859.00
	02 - Steam Generation Plant	Manatee U1	31100	4.10%	56,430.25	56,430.25
	02 - Steam Generation Plant	Manatee U1	31200	4.80%	477,896.88	462,142.42
	02 - Steam Generation Plant	Manatee U2	31100	4.10%	56,332.75	56,332.75
	02 - Steam Generation Plant	Manatee U2	31200	4.00%	508,734.36	508,552.43
	02 - Steam Generation Plant	Martin Comm	31200	4.10%	31,631.74	31,631.74
	02 - Steam Generation Plant	Martin U1	31100	1.50%	36,810.86	36,810.86
	02 - Steam Generation Plant	Martin U1	31200	1.80%	524,263.86	529,824.51
	02 - Steam Generation Plant	Martin U2	31100	1.50%	36,845.37	36,845.37
	02 - Steam Generation Plant	Martin U2	31200	1.50%	520,421.20	525,572.76
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.70%	127,911.34	127,911.34
	02 - Steam Generation Plant	PtEverglades Comm	31200	2.20%	51,132.85	67,787.69
	02 - Steam Generation Plant	PtEverglades U1	31200	6.70%	461,988.64	458,060.74
	02 - Steam Generation Plant	PtEverglades U2	31200	6.10%	475,113.36	480,321.84
	02 - Steam Generation Plant	PtEverglades U3	31200	4.00%	512,296.04	507,658.33
	02 - Steam Generation Plant	PtEverglades U4	31200	3.60%	517,303.41	517,303.41
	02 - Steam Generation Plant	Riviera Comm	31100	1.90%	60,973.18	60,973.18
	02 - Steam Generation Plant	Riviera Comm	31200	0.40%	11,495.25	11,495.25
	02 - Steam Generation Plant	Riviera U3	31200	1.70%	449,392.38	453,591.63
	02 - Steam Generation Plant	Riviera U4	31200	1.40%	433,421.96	437,621.87
	02 - Steam Generation Plant	Sanford U3	31100	4.00%	54,282.08	54,282.08
	02 - Steam Generation Plant	Sanford U3	31200	3.60%	434,357.43	425,269.85
	02 - Steam Generation Plant	Scherer U4	31200	1.90%	515,653.32	515,653.32
	02 - Steam Generation Plant	SJRPP - Comm	31100	3.10%	43,193.33	43,193.33
	02 - Steam Generation Plant	SJRPP - Comm	31200	2.00%	66,188.18	0.00
	02 - Steam Generation Plant	SJRPP U1	31200	2.20%	107,594.02	779.50
	02 - Steam Generation Plant	SJRPP U2	31200	2.30%	107,562.94	779.51
	02 - Steam Generation Plant	Turkey Pt Comm Fsil	31100	2.30%	59,056.19	59,056.19
	02 - Steam Generation Plant	Turkey Pt Comm Fsil	31200	2.10%	37,954.50	37,954.50
	02 - Steam Generation Plant	Turkey Pt U1	31200	2.00%	543,842.20	545,584.31
	02 - Steam Generation Plant	Turkey Pt U2	31200	1.80%	502,946.49	504,688.53
	05 - Other Generation Plant	FtLauderdale Comm	34100	4.10%	58,859.79	58,859.79
	05 - Other Generation Plant	FtLauderdale Comm	34500	4.10%	34,502.21	34,502.21
	05 - Other Generation Plant	FtLauderdale U4	34300	5.00%	463,054.20	462,254.20
	05 - Other Generation Plant	FtLauderdale U5	34300	3.70%	474,559.99	473,359.99
	05 - Other Generation Plant	FtMyers U2 CC	34300	5.50%	4,970.69	21,625.54
	05 - Other Generation Plant	Martin U3	34300	5.80%	411,933.88	418,031.16
	05 - Other Generation Plant	Martin U4	34300	5.70%	404,560.55	410,632.93
	05 - Other Generation Plant	Martin U8	34300	5.50%	13,876.71	4,688.46
	05 - Other Generation Plant	Putnam Comm	34100	4.10%	82,857.82	82,857.82
	05 - Other Generation Plant	Putnam Comm	34300	6.30%	3,138.97	3,138.97
	05 - Other Generation Plant	Putnam U1	34300	5.20%	332,065.69	330,765.69
	05 - Other Generation Plant	Putnam U2	34300	5.40%	365,469.22	364,509.68
	05 - Other Generation Plant	Sanford U4	34300	5.60%	98,339.95	80,349.32
	05 - Other Generation Plant	Sanford U5	34300	5.70%	56,521.05	38,489.84
03 - Continuous Emission Monitoring Total					12,474,967.00	11,867,698.60

Florida Power & Light Company
Environmental Cost Recovery Clause
2008 Annual Capital Depreciation Schedule

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Actual Balance 12/31/07	Actual Balance 12/31/08
04 - Clean Closure Equivalency Demonstration						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.70%	17,254.20	17,254.20
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.70%	19,812.30	19,812.30
	02 - Steam Generation Plant	Turkey Pt Comm Fsil	31100	2.30%	21,799.28	21,799.28
04 - Clean Closure Equivalency Demonstration Total					**58,865.78**	**58,865.78**
05 - Maintenance of Above Ground Fuel Tanks						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.70%	901,636.88	901,636.88
	02 - Steam Generation Plant	Manatee Comm	31100	4.90%	3,111,263.35	3,111,263.35
	02 - Steam Generation Plant	Manatee Comm	31200	14.10%	174,543.23	174,543.23
	02 - Steam Generation Plant	Manatee U1	31200	4.80%	104,845.35	104,845.35
	02 - Steam Generation Plant	Manatee U2	31200	4.00%	127,429.19	127,429.19
	02 - Steam Generation Plant	Martin Comm	31100	1.70%	1,110,450.32	1,110,450.32
	02 - Steam Generation Plant	Martin U1	31100	1.50%	176,338.83	176,338.83
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.70%	1,132,078.22	1,132,078.22
	02 - Steam Generation Plant	Riviera Comm	31100	1.90%	1,081,354.77	1,081,354.77
	02 - Steam Generation Plant	Sanford U3	31100	4.00%	796,754.11	796,754.11
	02 - Steam Generation Plant	SJRPP - Comm	31100	3.10%	42,091.24	42,091.24
	02 - Steam Generation Plant	SJRPP - Comm	31200	2.00%	2,292.39	2,292.39
	02 - Steam Generation Plant	Turkey Pt Comm Fsil	31100	2.30%	87,560.23	87,560.23
	02 - Steam Generation Plant	Turkey Pt U2	31100	2.10%	42,158.96	42,158.96
	05 - Other Generation Plant	FtLauderdale Comm	34200	4.40%	898,110.65	898,110.65
	05 - Other Generation Plant	FtLauderdale GTs	34200	4.50%	584,290.23	584,290.23
	05 - Other Generation Plant	FtMyers GTs	34200	5.00%	68,893.65	68,893.65
	05 - Other Generation Plant	PtEverglades GTs	34200	5.10%	2,359,099.94	2,359,099.94
	05 - Other Generation Plant	Putnam Comm	34200	3.70%	749,025.94	749,025.94
05 - Maintenance of Above Ground Fuel Tanks Total					**13,550,217.48**	**13,550,217.48**
07 - Relocate Turbine Lube Oil Piping						
	03 - Nuclear Generation Plant	StLucie U1	32300	1.20%	31,030.00	31,030.00
07 - Relocate Turbine Lube Oil Piping Total					**31,030.00**	**31,030.00**
08 - Oil Spill Clean-up/Response Equipment						
	02 - Steam Generation Plant	Amortizable	31670	7-Year	343,854.35	390,260.32
	02 - Steam Generation Plant	Martin Comm	31600	3.20%	23,107.32	23,107.32
	05 - Other Generation Plant	Amortizable	34650	5-Year	0.00	9,274.60
	05 - Other Generation Plant	Amortizable	34670	7-Year	45,699.54	45,699.54
	08 - General Plant	Amortizable	39190	3-Year	1,943.47	1,943.47
08 - Oil Spill Clean-up/Response Equipment Total					**414,604.68**	**470,285.25**
10 - Reroute Storm Water Runoff						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.40%	117,793.83	117,793.83
10 - Reroute Storm Water Runoff Total					**117,793.83**	**117,793.83**
12 - Scherer Discharge Pipline						
	02 - Steam Generation Plant	Scherer Comm	31000	0.00%	9,936.72	9,936.72
	02 - Steam Generation Plant	Scherer Comm	31100	1.60%	524,872.97	524,872.97
	02 - Steam Generation Plant	Scherer Comm	31200	1.60%	328,761.62	328,761.62
	02 - Steam Generation Plant	Scherer Comm	31400	1.00%	689.11	689.11
12 - Scherer Discharge Pipline Total					**864,260.42**	**864,260.42**
20 - Wastewater/Stormwater Discharge Elimination						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.70%	706,500.94	706,500.94
	02 - Steam Generation Plant	Martin U1	31200	1.80%	380,994.77	380,994.77
	02 - Steam Generation Plant	Martin U2	31200	1.50%	416,671.92	416,671.92
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.70%	296,707.34	296,707.34
	02 - Steam Generation Plant	Riviera Comm	31100	1.90%	560,786.81	560,786.81
20 - Wastewater/Stormwater Discharge Elimination Total					**2,361,661.78**	**2,361,661.78**
21 - St. Lucie Turtle Nets						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.40%	828,789.34	249,319.93
21 - St. Lucie Turtle Nets Total					**828,789.34**	**249,319.93**

Florida Power & Light Company
Environmental Cost Recovery Clause
2008 Annual Capital Depreciation Schedule

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Actual Balance 12/31/07	Actual Balance 12/31/08
23 - Spill Prevention Clean-Up & Countermeasures						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.70%	665,907.33	689,323.23
	02 - Steam Generation Plant	CapeCanaveral Comm	31400	0.70%	13,451.85	13,451.85
	02 - Steam Generation Plant	CapeCanaveral Comm	31500	1.90%	13,450.30	33,805.48
	02 - Steam Generation Plant	CapeCanaveral U1	31100	2.00%	0.00	0.00
	02 - Steam Generation Plant	CapeCanaveral U2	31100	1.30%	0.00	0.00
	02 - Steam Generation Plant	Cutler Comm	31400	0.00%	12,236.00	12,236.00
	02 - Steam Generation Plant	Cutler U5	31400	0.20%	18,388.00	18,388.00
	02 - Steam Generation Plant	Manatee Comm	31100	4.90%	336,763.43	741,087.68
	02 - Steam Generation Plant	Manatee Comm	31500	3.70%	5,000.00	25,640.57
	02 - Steam Generation Plant	Manatee U1	31500	3.60%	0.00	0.00
	02 - Steam Generation Plant	Manatee U2	31500	3.60%	0.00	0.00
	02 - Steam Generation Plant	Martin Comm	31100	1.70%	0.00	378,539.84
	02 - Steam Generation Plant	Martin U1	31100	1.50%	0.00	0.00
	02 - Steam Generation Plant	Martin U2	31100	1.50%	0.00	0.00
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.70%	10,379.00	2,952,949.32
	02 - Steam Generation Plant	PtEverglades Comm	31500	2.30%	0.00	7,782.85
	02 - Steam Generation Plant	PtEverglades U3	31100	2.60%	0.00	0.00
	02 - Steam Generation Plant	PtEverglades U4	31100	2.60%	0.00	0.00
	02 - Steam Generation Plant	Riviera Comm	31100	1.90%	205,014.03	205,014.03
	02 - Steam Generation Plant	Riviera U3	31200	1.70%	736,958.97	736,958.97
	02 - Steam Generation Plant	Riviera U4	31200	1.40%	894,298.77	894,298.77
	02 - Steam Generation Plant	Sanford U3	31100	4.00%	213,687.21	850,530.75
	02 - Steam Generation Plant	Sanford U3	31200	3.60%	211,727.22	211,727.22
	02 - Steam Generation Plant	Turkey Pt Comm Fsil	31100	2.30%	0.00	85,779.76
	02 - Steam Generation Plant	Turkey Pt Comm Fsil	31500	2.10%	13,559.00	13,559.00
	02 - Steam Generation Plant	Turkey Pt U1	31100	2.50%	0.00	0.00
	02 - Steam Generation Plant	Turkey Pt U2	31100	2.10%	0.00	0.00
	03 - Nuclear Generation Plant	StLucie U1	32300	1.20%	404,549.02	404,835.79
	03 - Nuclear Generation Plant	StLucie U1	32400	1.70%	437,714.57	437,945.38
	03 - Nuclear Generation Plant	StLucie U2	32300	1.90%	396,779.37	544,808.31
	05 - Other Generation Plant	Amortizable	34670	7-Year	7,065.10	7,065.10
	05 - Other Generation Plant	FtLauderdale Comm	34100	4.10%	189,219.17	189,219.17
	05 - Other Generation Plant	FtLauderdale Comm	34200	4.40%	1,480,169.46	1,480,169.46
	05 - Other Generation Plant	FtLauderdale Comm	34300	1.80%	28,250.00	28,250.00
	05 - Other Generation Plant	FtLauderdale GTs	34100	2.20%	92,726.74	92,726.74
	05 - Other Generation Plant	FtLauderdale GTs	34200	4.50%	513,250.07	513,250.07
	05 - Other Generation Plant	FtMyers GTs	34100	2.10%	98,714.92	98,714.92
	05 - Other Generation Plant	FtMyers GTs	34200	5.00%	629,983.29	629,983.29
	05 - Other Generation Plant	FtMyers GTs	34500	2.90%	12,430.00	12,430.00
	05 - Other Generation Plant	FtMyers U2 CC	34300	5.50%	49,727.00	49,727.00
	05 - Other Generation Plant	FtMyers U3 CC	34500	4.80%	12,430.00	12,430.00
	05 - Other Generation Plant	Martin Comm	34100	3.40%	61,215.95	61,215.95
	05 - Other Generation Plant	Martin U8	34200	4.80%	0.00	84,868.00
	05 - Other Generation Plant	Martin U8	34300	5.50%	0.00	0.00
	05 - Other Generation Plant	PtEverglades GTs	34100	1.50%	454,080.68	454,080.68
	05 - Other Generation Plant	PtEverglades GTs	34200	5.10%	1,703,610.61	1,703,610.61
	05 - Other Generation Plant	Putnam Comm	34100	4.10%	148,511.20	148,511.20
	05 - Other Generation Plant	Putnam Comm	34200	3.70%	1,713,191.94	1,713,191.94
	05 - Other Generation Plant	Putnam Comm	34500	4.20%	60,746.93	60,746.93
	06 - Transmission Plant - Electric		35200	2.50%	951,562.91	951,562.91
	06 - Transmission Plant - Electric		35300	2.80%	177,981.88	177,981.88
	07 - Distribution Plant - Electric		36100	2.60%	2,862,093.44	2,862,093.44
	08 - General Plant		39000	2.70%	12,843.35	12,843.35
23 - Spill Prevention Clean-Up & Countermeasures Total					15,849,668.71	20,603,335.44
24 - Manatee Reburn						
	02 - Steam Generation Plant	Manatee U1	31200	4.80%	16,771,308.37	16,771,308.37
	02 - Steam Generation Plant	Manatee U2	31200	4.00%	16,091,238.26	16,091,259.94
24 - Manatee Reburn Total					32,862,546.63	32,862,568.31

Florida Power & Light Company
Environmental Cost Recovery Clause
2008 Annual Capital Depreciation Schedule

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Actual Balance 12/31/07	Actual Balance 12/31/08
25 - PPE ESP Technology						
	02 - Steam Generation Plant	PtEverglades U1	31100	2.60%	298,709.93	298,709.93
	02 - Steam Generation Plant	PtEverglades U1	31200	6.70%	10,404,603.15	10,404,603.15
	02 - Steam Generation Plant	PtEverglades U1	31500	2.00%	2,500,248.85	2,500,248.85
	02 - Steam Generation Plant	PtEverglades U1	31600	1.00%	307,032.30	307,032.30
	02 - Steam Generation Plant	PtEverglades U2	31100	2.60%	184,084.01	184,084.01
	02 - Steam Generation Plant	PtEverglades U2	31200	6.10%	11,979,735.29	11,979,735.29
	02 - Steam Generation Plant	PtEverglades U2	31500	2.10%	3,954,581.63	3,954,581.63
	02 - Steam Generation Plant	PtEverglades U2	31600	1.70%	324,086.94	324,086.94
	02 - Steam Generation Plant	PtEverglades U3	31100	2.60%	4,812,793.71	713,693.44
	02 - Steam Generation Plant	PtEverglades U3	31200	4.00%	16,040,755.59	17,911,019.51
	02 - Steam Generation Plant	PtEverglades U3	31500	2.20%	2,404,282.44	4,304,056.69
	02 - Steam Generation Plant	PtEverglades U3	31600	1.00%	0.00	528,541.18
	02 - Steam Generation Plant	PtEverglades U4	31100	2.60%	0.00	313,275.79
	02 - Steam Generation Plant	PtEverglades U4	31200	3.60%	24,864,782.55	20,387,242.26
	02 - Steam Generation Plant	PtEverglades U4	31500	2.10%	2,875,365.39	6,729,950.05
	02 - Steam Generation Plant	PtEverglades U4	31600	1.30%	0.00	551,535.30
25 - PPE ESP Technology Total					**80,951,061.78**	**81,392,396.32**
26 - UST Remove/Replace						
	08 - General Plant		39000	2.70%	492,916.42	492,916.42
26 - UST Remove/Replace Total					**492,916.42**	**492,916.42**
31 - Clean Air Interstate Rule (CAIR)						
	02 - Steam Generation Plant	Manatee U1	31400	3.70%	0.00	277,326.13
	02 - Steam Generation Plant	Manatee U2	31200	4.00%	0.00	0.00
	02 - Steam Generation Plant	Manatee U2	31400	3.00%	0.00	0.00
	02 - Steam Generation Plant	Martin U1	31200	1.80%	0.00	10,580,457.33
	02 - Steam Generation Plant	Martin U1	31400	1.30%	0.00	6,985,668.11
	02 - Steam Generation Plant	Martin U2	31200	1.50%	0.00	0.00
	02 - Steam Generation Plant	Martin U2	31400	0.80%	0.00	0.00
	02 - Steam Generation Plant	SJRPP U1	31200	2.20%	0.00	210,549.74
	02 - Steam Generation Plant	SJRPP U2	31200	2.30%	0.00	222,893.37
	05 - Other Generation Plant	FtLauderdale GTs	34300	2.20%	0.00	110,241.57
	05 - Other Generation Plant	FtMyers GTs	34300	3.10%	57,722.33	57,855.19
	05 - Other Generation Plant	PtEverglades GTs	34300	2.60%	0.00	107,874.44
31 - Clean Air Interstate Rule (CAIR) Total					**57,722.33**	**18,552,865.88**
Grand Total					**178,389,499.35**	**200,796,398.27**

APPENDIX I

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

JANUARY 2009 – DECEMBER 2009
ESTIMATED/ACTUAL TRUE-UP

TJK-2
DOCKET NO. 090007-EI
FPL WITNESS: T.J. KEITH
EXHIBIT ______

FLORIDA PUBLIC SERVICE COMMISSION
1 DOCKET NO. 090007-EI EXHIBIT 4
COMPANY Florida Power & Light Company (Direct)
WITNESS T. J. Keith (TJK-2)
DATE 11/02/09

Form 42-1E

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up
for the Period January through December 2009

Line No.		
1	Over/(Under) Recovery for the Current Period (Form 42-2E, Page 2 of 2, Line 5)	$3,570,693
2	Interest Provision (Form 42-2E, Page 2 of 2, Line 6)	$32,060
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	$3,602,753

( ) Reflects Underrecovery

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up Amount for the Period
January through December 2009

Line No.		January	February	March	April	May	June
1	ECRC Revenues (net of Revenue Taxes)	$6,552,273	$6,531,467	$6,044,536	$6,548,128	$7,264,092	$8,066,158
2	True-up Provision (Order No. PSC-08-0775-FOF-EI)	(212,850)	(212,850)	(212,850)	(212,850)	(212,850)	(212,850)
3	ECRC Revenues Applicable to Period (Lines 1 + 2)	6,339,424	6,318,617	5,831,686	6,335,278	7,051,242	7,853,308
4	Jurisdictional ECRC Costs						
	a - O&M Activities (Form 42-5E, Line 9)	863,689	420,976	881,398	972,078	904,281	972,897
	b - Capital Investment Projects (Form 42-7E, Line 9)	3,626,553	3,724,876	4,080,372	4,563,538	4,928,981	5,441,109
	c - Total Jurisdictional ECRC Costs	4,490,242	4,145,852	4,961,770	5,535,616	5,833,262	6,414,006
5	Over/(Under) Recovery (Line 3 - Line 4c)	1,849,182	2,172,765	869,917	799,662	1,217,981	1,439,302
6	Interest Provision (Form 42-3A, Line 10)	649	2,179	2,780	2,447	2,160	2,424
7	Prior Periods True-Up to be (Collected)/Refunded in 2009	(2,554,197)	(491,516)	1,896,278	2,981,824	3,996,783	5,429,774
	a - Deferred True-Up from 2008 (Form 42-1A, Line 7)	2,694,222	2,694,222	2,694,222	2,694,222	2,694,222	2,694,222
8	True-Up Collected /(Refunded) (See Line 2)	212,850	212,850	212,850	212,850	212,850	212,850
9	End of Period True-Up (Lines 5+6+7+7a+8)	2,202,706	4,590,500	5,676,046	6,691,005	8,123,996	9,778,572
10	Adjustments to Period Total True-Up Including Interest						
11	End of Period Total Net True-Up (Lines 9+10)	$2,202,706	$4,590,500	$5,676,046	$6,691,005	$8,123,996	$9,778,572

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up Amount for the Perio
January through December 2009

Line No.		July	August	September	October	November	December	End of Period Amount
1	ECRC Revenues (net of Revenue Taxes)	$8,679,706	$8,627,280	$8,866,037	$7,580,020	$7,060,130	$6,869,837	$88,689,664
2	True-up Provision (Order No. PSC-08-0775-FOF-EI)	(212,850)	(212,850)	(212,850)	(212,850)	(212,850)	(212,850)	(2,554,197)
3	ECRC Revenues Applicable to Period (Lines 1 + 2)	8,466,856	8,414,430	8,653,187	7,367,170	6,847,280	6,656,987	86,135,467
4	Jurisdictional ECRC Costs							
	a - O&M Activities (Form 42-5E, Line 9)	1,614,289	783,488	1,114,506	1,155,541	1,588,305	1,425,362	12,696,810
	b - Capital Investment Projects (Form 42-7E, Line 9)	5,962,616	6,415,120	6,859,201	7,308,458	7,992,493	8,964,647	69,867,964
	c - Total Jurisdictional ECRC Costs	7,576,905	7,198,608	7,973,707	8,463,998	9,580,799	10,390,009	82,564,774
5	Over/(Under) Recovery (Line 3 - Line 4c)	889,951	1,215,822	679,480	(1,096,828)	(2,733,518)	(3,733,021)	3,570,693
6	Interest Provision (Form 42-3A, Line 10)	3,013	3,383	3,722	3,725	3,229	2,349	32,060
7	Prior Periods True-Up to be (Collected)/Refunded in 2009	7,084,350	8,190,164	9,622,219	10,518,271	9,638,018	7,120,578	(2,554,197)
	a - Deferred True-Up from 2008 (Form 42-1A, Line 7)	2,694,222	2,694,222	2,694,222	2,694,222	2,694,222	2,694,222	
8	True-Up Collected /(Refunded) (See Line 2)	212,850	212,850	212,850	212,850	212,850	212,850	2,554,197
9	End of Period True-Up (Lines 5+6+7+7a+8)	10,884,386	12,316,441	13,212,493	12,332,240	9,814,800	6,296,977	3,602,753
10	Adjustments to Period Total True-Up Including Interest							
11	End of Period Total Net True-Up (Lines 9+10)	$10,884,386	$12,316,441	$13,212,493	$12,332,240	$9,814,800	$6,296,977	$3,602,753

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up Amount for the Period
January through December 2009

Interest Provision (In Dollars)

Line No.		January	February	March	April	May	June
1	Beginning True-Up Amount (Form 42-2E, Lines 7 + 7a + 10)	$140,025	$2,202,706	$4,590,500	$5,676,046	$6,691,005	$8,123,996
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2E, Lines 5 + 8)	2,202,057	4,588,321	5,673,266	6,688,558	8,121,836	9,776,148
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	$2,342,082	$6,791,027	$10,263,766	$12,364,604	$14,812,841	$17,900,144
4	Average True-Up Amount (Line 3 x 1/2)	$1,171,041	$3,395,513	$5,131,883	$6,182,302	$7,406,420	$8,950,072
5	Interest Rate (First Day of Reporting Month)	0.54000%	0.79000%	0.75000%	0.55000%	0.40000%	0.30000%
6	Interest Rate (First Day of Subsequent Month)	0.79000%	0.75000%	0.55000%	0.40000%	0.30000%	0.35000%
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	1.33000%	1.54000%	1.30000%	0.95000%	0.70000%	0.65000%
8	Average Interest Rate (Line 7 x 1/2)	0.66500%	0.77000%	0.65000%	0.47500%	0.35000%	0.32500%
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.05542%	0.06417%	0.05417%	0.03958%	0.02917%	0.02708%
10	Interest Provision for the Month (Line 4 x Line 9)	$649	$2,179	$2,780	$2,447	$2,160	$2,424

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Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up Amount for the Perio
January through December 2009

Interest Provision (In Dollars)

Line No.		July	August	September	October	November	December	End of Period Amount
1	Beginning True-Up Amount (Form 42-2E, Lines 7 + 7a + 10)	$9,778,572	$10,884,386	$12,316,441	$13,212,493	$12,332,240	$9,814,800	N/A
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2E, Lines 5 + 8)	10,881,373	12,313,058	13,208,771	12,328,515	9,811,571	6,294,628	N/A
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	$20,659,945	$23,197,444	$25,525,212	$25,541,008	$22,143,811	$16,109,428	N/A
4	Average True-Up Amount (Line 3 x 1/2)	$10,329,972	$11,598,722	$12,762,606	$12,770,504	$11,071,905	$8,054,714	N/A
5	Interest Rate (First Day of Reporting Month)	0.35000%	0.35000%	0.35000%	0.35000%	0.35000%	0.35000%	N/A
6	Interest Rate (First Day of Subsequent Month)	0.35000%	0.35000%	0.35000%	0.35000%	0.35000%	0.35000%	N/A
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	0.70000%	0.70000%	0.70000%	0.70000%	0.70000%	0.70000%	N/A
8	Average Interest Rate (Line 7 x 1/2)	0.35000%	0.35000%	0.35000%	0.35000%	0.35000%	0.35000%	N/A
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.02917%	0.02917%	0.02917%	0.02917%	0.02917%	0.02917%	N/A
10	Interest Provision for the Month (Line 4 x Line 9)	$3,013	$3,383	$3,722	$3,725	$3,229	$2,349	$32,060

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Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-Up Amount for the Period
January 2009 - December 2009

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 Air Operating Permit Fees-O&M	$950,185	$1,958,100	($1,007,915)	-51.5%
	3a Continuous Emission Monitoring Systems-O&M	$961,773	$999,894	($38,121)	-3.8%
	5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	$1,391,496	$1,067,572	$323,924	30.3%
	8a Oil Spill Cleanup/Response Equipment-O&M	$241,800	$241,800	$0	0.0%
	13 RCRA Corrective Action-O&M	$13,742	$50,000	($36,258)	-72.5%
	14 NPDES Permit Fees-O&M	$124,400	$124,900	($500)	-0.4%
	17a Disposal of Noncontainerized Liquid Waste-O&M	$293,044	$323,000	($29,956)	-9.3%
	19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	$2,889,680	$2,693,288	$196,392	7.3%
	19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	$696,600	$728,712	($32,112)	-4.4%
	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	($344,421)	($983,208)	$638,787	-65.0%
	21 St. Lucie Turtle Net	$0	$0	$0	0.0%
	22 Pipeline Integrity Management	$250,628	$40,000	$210,628	526.6%
	23 SPCC-Spill Prevention, Control & Countermeasures	$864,252	$688,000	$176,252	25.6%
	24 Manatee Reburn	$500,000	$500,000	$0	0.0%
	25 Port Everglades ESP	$2,049,829	$2,276,313	($226,484)	-9.9%
	26 UST Replacement/Removal	$0	$0	$0	0.0%
	27 Lowest Quality Water Source	$304,663	$258,471	$46,192	17.9%
	28 CWA 316(b) Phase II Rule	($230,121)	$607,000	($837,121)	-137.9%
	29 SCR Consumables	$293,009	$350,000	($56,991)	-16.3%
	30 HBMP	$40,767	$40,000	$767	1.9%
	31 CAIR Compliance	$1,123,477	$1,611,396	($487,919)	-30.3%
	32 BART	$0	$0	$0	0.0%
	34 St. Lucie Cooling Water System Inspection & Maintenance	$476,960	$1,800,000	($1,323,040)	-73.5%
	35 Martin Plant Drinking Water System Compliance	$17,000	$17,000	$0	0.0%
	36 Low-Level Radioactive Waste Storage	($887)	$1,000,000	($1,000,887)	-100.1%
	37 DeSoto Next Generation Solar Energy Center	$237,100	$467,475	($230,375)	-49.3%
	38 Space Coast Next Generatino Solar Energy Center	$30,240	$20,000	$10,240	51.2%
	39 Martin Next Generation Solar Energy Center	$0	$0	$0	0.0%
	40 Greenhouse Gas Reduction Program	$0	$50,000	($50,000)	-100.0%
	41 Manatee Temporary Heating System Project	$12,500	$0	$12,500	NA
	42 Turkey Point Cooling Canal Monitoring Plan	$200,000	$0	$200,000	NA
2	Total O&M Activities	$12,827,484	$16,369,481	($3,541,997)	-21.6%
3	Recoverable Costs Allocated to Energy	$ 6,313,166	$7,651,803	($1,338,637)	-17.5%
4a	Recoverable Costs Allocated to CP Demand	$ 3,904,754	$6,304,506	($2,399,752)	-38.1%
4b	Recoverable Costs Allocated to GCP Demand	$ 2,609,564	$2,413,172	$196,392	8.1%

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-08-0775-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 Amount for the Period
January 2009 - December 2009

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	$ 105,591	$ (203,715)	$ 103,425	$ 99,469	$ 102,993	$ 108,330	$316,093
	3a Continuous Emission Monitoring Systems-O&M	162,608	50,437	39,806	23,105	74,143	48,244	398,343
	5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	0	33,157	239,877	208,902	116,446	76,614	674,996
	8a Oil Spill Cleanup/Response Equipment-O&M	10,653	31,509	6,673	7,654	12,130	13,254	81,873
	13 RCRA Corrective Action-O&M	0	0	2,000	3,454	745	0	6,199
	14 NPDES Permit Fees-O&M	112,900	0	0	11,500	0	0	124,400
	17a Disposal of Noncontainerized Liquid Waste-O&M	(2,118)	60,000	43,906	20,625	44,081	56,550	223,044
	19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	164,838	173,475	201,065	268,183	328,062	301,960	1,437,583
	19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	33,272	63,732	24,348	53,221	62,148	33,017	269,738
	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	(12,858)	(12,858)	(15,015)	(53,391)	(25,466)	(32,119)	(151,707)
	21 St. Lucie Turtle Net	0	0	0	0	0	0	0
	22 Pipeline Integrity Management	13,483	4,277	2,156	108,576	9,612	8,524	146,628
	23 SPCC - Spill Prevention, Control & Countermeasures	49,567	48,754	47,812	50,941	34,589	36,840	268,503
	24 Manatee Reburn	56,403	68,330	21,972	27,326	111,480	79,128	364,639
	25 Pt. Everglades ESP Technology	49,224	37,792	77,731	53,549	87,190	230,637	536,123
	26 UST Replacement/Removal	0	0	0	0	0	0	0
	27 Lowest Quality Water Source	25,526	25,750	25,261	24,550	25,617	26,736	153,440
	28 CWA 316(b) Phase II Rule	2,040	87	3,500	0	(204,024)	(61,483)	(259,880)
	29 SCR Consumables	22,689	29,011	32,446	37,765	7,566	14,032	143,509
	30 HBMP	1,556	1,556	2,229	2,511	4,142	13,646	25,640
	31 CAIR Compliance	96,844	33,097	25,707	82,197	152,338	56,530	446,713
	32 BART	0	0	0	0	0	0	0
	34 St. Lucie Cooling Water System Inspection & Maintenance	19,814	35,338	52,222	(2,069)	15,089	18,244	138,638
	35 Martin Plant Drinking Water System Compliance	0	0	0	0	0	0	0
	36 Low-Level Radioactive Waste Storage	7,727	(8,614)	0	0	0	0	(887)
	37 DeSoto Next Generation Solar Energy Center	0	0	0	0	0	0	0
	38 Space Coast Next Generation Solar Energy Center	0	0	0	0	0	0	0
	39 Martin Next Generation Solar Energy Center	0	0	0	0	0	0	0
	40 Greenhouse Gas Reduction Program	0	0	0	0	0	0	0
	41 Manatee Temporary Heating System Project	0	0	0	0	0	0	0
	42 Turkey Point Cooling Canal Monitoring Plan	0	0	0	0	0	0	0
2	Total of O&M Activities	$ 873,073	$ 424,429	$ 890,435	$ 981,382	$ 912,195	$ 981,998	$ 5,063,512
3	Recoverable Costs Allocated to Energy	$ 490,394	$ 96,047	$ 336,728	$ 300,597	$ 569,440	$ 575,330	$ 2,368,537
4a	Recoverable Costs Allocated to CP Demand	$ 241,184	$ 178,250	$ 375,985	$ 435,945	$ 38,036	$ 128,051	$ 1,397,450
4b	Recoverable Costs Allocated to GCP Demand	$ 141,495	$ 150,132	$ 177,722	$ 244,840	$ 304,719	$ 278,617	$ 1,297,525
5	Retail Energy Jurisdictional Factor	98.69261%	98.69261%	98.69261%	98.69261%	98.69261%	98.69261%	
6a	Retail CP Demand Jurisdictional Factor	98.76729%	98.76729%	98.76729%	98.76729%	98.76729%	98.76729%	
6b	Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	
7	Jurisdictional Energy Recoverable Costs (A)	$ 483,983	$ 94,792	$ 332,326	$ 296,667	$ 561,995	$ 567,808	$ 2,337,571
8a	Jurisdictional CP Demand Recoverable Costs (B)	$ 238,211	$ 176,052	$ 371,350	$ 430,571	$ 37,567	$ 126,472	$ 1,380,223
8b	Jurisdictional GCP Demand Recoverable Costs (C)	$ 141,495	$ 150,132	$ 177,722	$ 244,840	$ 304,719	$ 278,617	$ 1,297,525
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 863,689	$ 420,976	$ 881,398	$ 972,078	$ 904,281	$ 972,897	$ 5,015,319

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.

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Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated / Actual Amount for the Period
January 2009 - December 2009

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	$ 105,682	$ 105,682	$ 105,682	$ 105,682	$ 105,682	$ 105,682	$634,092	$950,185			$950,185
	3a Continuous Emission Monitoring Systems-O&M	231,821	36,308	126,461	38,308	36,072	94,460	563,430	961,773			961,773
	5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	125,500	168,000	0	67,000	30,500	325,500	716,500	1,391,496	1,391,496		
	8a Oil Spill Cleanup/Response Equipment-O&M	48,577	25,170	19,577	21,877	19,577	25,149	159,927	241,800			241,800
	13 RCRA Corrective Action-O&M	1,257	1,257	1,257	1,257	1,257	1,258	7,543	13,742	13,742		
	14 NPDES Permit Fees-O&M	0	0	0	0	0	0	0	124,400	124,400		
	17a Disposal of Noncontainerized Liquid Waste-O&M	45,000	0	0	25,000	0	0	70,000	293,044			293,044
	19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	150,000	150,000	253,032	253,032	336,033	310,000	1,452,097	2,889,680		2,889,680	
	19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	45,000	45,000	70,620	100,620	100,622	65,000	426,862	696,600	643,015		53,585
	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	(32,119)	(32,119)	(32,119)	(32,119)	(32,119)	(32,119)	(192,714)	(344,421)			(344,421)
	21 St. Lucie Turtle Net	0	0	0	0	0	0	0	0	0		
	22 Pipeline Integrity Management	64,000	0	0	0	40,000	0	104,000	250,628	250,628		
	23 SPCC - Spill Prevention, Control & Countermeasures	49,000	62,000	86,000	211,000	131,749	56,000	595,749	864,252	864,252		
	24 Manatee Reburn	78,022	11,000	11,498	10,000	11,667	13,174	135,361	500,000			500,000
	25 Pt. Everglades ESP Technology	627,129	131,235	230,971	226,111	110,971	187,289	1,513,706	2,049,829			2,049,829
	26 UST Replacement/Removal	0	0	0	0	0	0	0	0	0		
	27 Lowest Quality Water Source	25,203	25,203	25,203	25,203	25,203	25,208	151,223	304,663	304,663		
	28 CWA 316(b) Phase II Rule	18,759	3,000	2,000	2,000	2,000	2,000	29,759	(230,121)	(230,121)		
	29 SCR Consumables	24,000	24,000	26,000	24,500	24,500	26,500	149,500	293,009			293,009
	30 HBMP	1,556	1,556	1,556	1,556	1,556	7,347	15,127	40,767	40,767		
	31 CAIR Compliance	40,000	40,000	40,000	56,219	460,545	40,000	676,764	1,123,477			1,123,477
	32 BART	0	0	0	0	0	0	0	0			0
	34 St. Lucie Cooling Water System Inspection & Maintenance	32,040	28,040	184,040	39,041	30,581	24,580	338,322	476,960	476,960		
	35 Martin Plant Drinking Water System Compliance	0	0	0	17,000	0	0	17,000	17,000	17,000		
	36 Low-Level Radioactive Waste Storage	0	0	0	0	0	0	0	(887)	(819)		(68)
	37 DeSoto Next Generation Solar Energy Center	0	13,300	13,300	13,300	98,600	98,600	237,100	237,100	237,100		
	38 Space Coast Next Generation Solar Energy Center	0	0	7,560	7,560	7,560	7,560	30,240	30,240	30,240		
	39 Martin Next Generation Solar Energy Center	0	0	0	0	0	0	0	0	0		
	40 Greenhouse Gas Reduction Program	0	0	0	0	0	0	0	0			
	41 Manatee Temporary Heating System Project	0	0	0	0	9,000	3,500	12,500	12,500			12,500
	42 Turkey Point Cooling Canal Monitoring Plan	0	0	0	0	100,000	100,000	200,000	200,000			200,000
2	Total of O&M Activities	$ 1,633,741	$ 791,946	$ 1,125,952	$ 1,167,461	$ 1,604,870	$ 1,440,002	$ 7,763,972	$ 12,827,484	$ 3,904,754	$ 2,609,564	$ 6,313,166
3	Recoverable Costs Allocated to Energy	$ 1,169,778	$ 342,942	$ 531,707	$ 481,522	$ 851,840	$ 566,839	$ 3,944,628	$ 6,313,166			
4a	Recoverable Costs Allocated to CP Demand	$ 337,306	$ 322,347	$ 364,556	$ 456,250	$ 440,340	$ 586,506	$ 2,507,305	$ 3,904,754			
4b	Recoverable Costs Allocated to GCP Demand	$ 126,657	$ 126,657	$ 229,689	$ 229,689	$ 312,690	$ 286,657	$ 1,312,039	$ 2,609,564			
5	Retail Energy Jurisdictional Factor	98.69261%	98.69261%	98.69261%	98.69261%	98.69261%	98.69261%					
6a	Retail CP Demand Jurisdictional Factor	98.76729%	98.76729%	98.76729%	98.76729%	98.76729%	98.76729%					
6b	Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%					
7	Jurisdictional Energy Recoverable Costs (A)	$ 1,154,484	$ 338,458	$ 524,755	$ 475,227	$ 840,703	$ 559,429	$ 3,893,056	$ 6,230,627			
8a	Jurisdictional CP Demand Recoverable Costs (B)	$ 333,148	$ 318,373	$ 360,062	$ 450,625	$ 434,912	$ 579,276	$ 2,476,396	$ 3,856,619			
8b	Jurisdictional GCP Demand Recoverable Costs (C)	$ 126,657	$ 126,657	$ 229,689	$ 229,689	$ 312,690	$ 286,657	$ 1,312,039	$ 2,609,564			
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 1,614,289	$ 783,488	$ 1,114,506	$ 1,155,541	$ 1,588,305	$ 1,425,362	$ 7,681,491	$ 12,696,810			

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 2009 - December 2009

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	$791,224	$787,974	$ 3,250	0.4%
3b	Continuous Emission Monitoring Systems-Capital	$951,183	$1,025,943	(74,760)	-7.3%
4b	Clean Closure Equivalency-Capital	$3,690	$3,692	(2)	-0.1%
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	$1,651,908	$1,648,976	2,932	0.2%
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	$1,517	$1,517	0	0.0%
8b	Oil Spill Cleanup/Response Equipment-Capital	$97,384	$111,495	(14,111)	-12.7%
10	Relocate Storm Water Runoff-Capital	$9,376	$9,377	(1)	0.0%
NA	SO2 Allowances-Negative Return on Investment	($257,980)	($278,987)	21,007	-7.5%
12	Scherer Discharge Pipeline-Capital	$61,280	$61,280	0	0.0%
17b	Disposal of Noncontainerized Liquid Waste-Capital	$0	$0	0	0.0%
20	Wastewater Discharge Elimination & Reuse	$236,106	$236,106	0	0.0%
21	St. Lucie Turtle Net	$114,621	$137,914	(23,293)	-16.9%
22	Pipeline Integrity Management	$0	$6,395	(6,395)	-100.0%
23	SPCC-Spill Prevention, Control & Countermeasures	$2,669,799	$2,525,090	144,709	5.7%
24	Manatee Reburn	$4,608,575	$4,609,917	(1,342)	0.0%
25	Pt. Everglades ESP Technology	$11,174,199	$11,251,101	(76,902)	-0.7%
26	UST Replacement/Removal	$65,487	$65,488	(1)	0.0%
31	CAIR Compliance	$22,192,708	$23,103,538	(910,830)	-3.9%
33	CAMR Compliance	$6,595,264	$5,934,022	661,242	11.1%
34	St. Lucie Cooling Water System Inspection & Maintenance	$0	$19,518	(19,518)	-100.0%
35	Martin Plant Drinking Water System Compliance	$28,162	$27,801	361	1.3%
36	Low-Level Radioactive Waste Storage	$27,338	$27,338	0	0.0%
37	DeSoto Next Generation Solar Energy Center	$10,870,525	$11,224,344	(353,819)	-3.2%
38	Space Coast Next Generation Solar Energy center	$1,357,538	$1,508,123	(150,585)	-10.0%
39	Martin Next Generation Solar Energy Center	$7,483,394	$11,788,849	(4,305,455)	-36.5%
41	Manatee Temporary Heating System Project	$22,849	$0	22,849	NA
42	Turkey Point Cooling Canal Monitoring Plan	$0	$0	0	0.0%
2	Total Investment Projects-Recoverable Costs	$ 70,756,147	$ 75,836,811	$ (5,080,664)	-6.7%
3	Recoverable Costs Allocated to Energy	$ 21,381,735	$ 21,891,398	$ (509,663)	-2.3%
4	Recoverable Costs Allocated to Demand	$ 49,374,412	$ 53,945,413	$ (4,571,001)	-8.5%

Notes:
Column(1) is the 12-Month Totals on Form 42-7E
Column(2) is the approved projected amount in accordance with FPSC Order No. PSC-08-0775-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 Amount for the Period
January 2009 - December 2009

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	$68,201	$67,789	$67,377	$66,965	$66,553	$ 66,141	$ 403,026
3b Continuous Emission Monitoring Systems-Capital	80,941	80,636	80,327	80,017	79,712	79,407	481,040
4b Clean Closure Equivalency-Capital	313	312	311	310	309	308	1,863
5b Maintenance of Stationary Above Ground Fuel	139,023	138,616	138,209	138,378	138,568	138,180	830,974
Storage Tanks-Capital							0
7 Relocate Turbine Lube Oil Underground Piping	128	128	127	127	127	127	764
to Above Ground-Capital							0
8b Oil Spill Cleanup/Response Equipment-Capital	7,184	7,140	7,101	7,050	7,186	7,543	43,204
10 Relocate Storm Water Runoff-Capital	788	787	786	785	783	782	4,711
NA SO2 Allowances-Negative Return on Investment	(21,890)	(21,771)	(21,642)	(21,954)	(22,218)	(22,035)	(131,510)
12 Scherer Discharge Pipeline-Capital	5,165	5,154	5,144	5,133	5,122	5,112	30,830
17b Disposal of Noncontainerized Liquid Waste-Capital	0	0	0	0	0	0	0
20 Wastewater Discharge Elimination & Reuse	19,861	19,827	19,794	19,760	19,726	19,692	118,660
21 St. Lucie Turtle Net	9,384	9,568	9,576	9,579	9,575	9,572	57,254
22 Pipeline Integrity Management	0	0	0	0	0	0	0
23 SPCC - Spill Prevention, Control & Countermeasures	224,878	224,447	224,229	223,790	223,294	222,799	1,343,437
24 Manatee Rebum	390,300	389,184	388,067	386,951	385,834	384,612	2,324,948
25 Pt. Everglades ESP Technology	942,744	940,195	937,643	935,094	932,589	930,220	5,618,485
26 UST Removal / Replacement	5,514	5,503	5,493	5,483	5,473	5,462	32,928
31 CAIR Compliance	1,244,509	1,311,657	1,396,666	1,532,443	1,676,061	1,809,519	8,970,855
33 CAMR Compliance	370,320	360,907	394,529	434,286	465,911	507,449	2,533,402
34 St. Lucie Cooling Water System Inspection & Maintenance	0	0	0	0	0	0	0
35 Martin Plant Drinking Water System Compliance	998	2,251	2,505	2,502	2,499	2,496	13,251
36 Low-Level Radioactive Waste Storage	0	0	0	0	0	0	0
37 DeSoto Next Generation Solar Energy Center	41,010	70,144	291,436	559,750	691,866	947,812	2,602,018
38 Space Coast Next Generation Solar Energy Center	65,396	66,095	66,674	72,820	78,985	80,075	430,045
39 Martin Next Generation Solar Energy Center	78,281	94,033	118,200	162,505	223,841	315,070	991,930
41 Manatee Temporary Heating System Project	0	0	0	0	0	0	0
42 Turkey Point Cooling Canal Monitoring Plan	0	0	0	0	0	0	0
2 Total Investment Projects - Recoverable Costs	$ 3,673,048	$3,772,602	$4,132,552	$4,621,774	$4,991,796	$5,510,343	$26,702,115
3 Recoverable Costs Allocated to Energy	$ 1,630,508	$1,634,231	$1,657,986	$1,691,281	$1,715,495	$1,751,576	$10,081,076
4 Recoverable Costs Allocated to Demand	$ 2,042,540	$2,138,371	$2,474,566	$2,930,493	$3,276,301	$3,758,767	$16,621,039
5 Retail Energy Jurisdictional Factor	98.69261%	98.69261%	98.69261%	98.69261%	98.69261%	98.69261%	
6 Retail Demand Jurisdictional Factor	98.76729%	98.76729%	98.76729%	98.76729%	98.76729%	98.76729%	
7 Jurisdictional Energy Recoverable Costs (B)	$ 1,609,191	$1,612,865	$1,636,310	$1,669,169	$1,693,067	$1,728,676	$ 9,949,278
8 Jurisdictional Demand Recoverable Costs (C)	$ 2,017,362	$2,112,011	$2,444,062	$2,894,369	$3,235,914	$3,712,433	$16,416,151
9 Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 3,626,553	$3,724,876	$4,080,372	$4,563,538	$4,928,981	$5,441,109	$26,365,429

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

Totals may not add due to rounding.

Form 42-7E
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Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated / Actual Amount for the Period
January 2009 - December 2009

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	Energy
1 Description of Investment Projects (A)										
2 Low NOx Burner Technology-Capital	$ 65,729	$ 65,317	$ 64,906	$ 64,494	$ 64,082	$ 63,670	$ 388,198	$ 791,224		$ 791,224
3b Continuous Emission Monitoring Systems-Capital	79,102	78,797	78,492	78,187	77,882	77,683	470,143	951,183		951,183
4b Clean Closure Equivalency-Capital	307	306	305	304	303	302	1,827	3,690	3,406	284
5b Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	137,770	137,359	136,949	136,539	136,128	136,189	820,934	1,651,908	1,524,838	127,070
7 Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	126	126	126	125	125	125	753	1,517	1,400	117
8b Oil Spill Cleanup/Response Equipment-Capital	8,203	8,803	8,828	9,054	9,361	9,931	54,180	97,384	89,893	7,491
10 Relocate Storm Water Runoff-Capital	781	779	778	777	776	774	4,665	9,376	8,655	721
NA SO2 Allowances-Negative Return on Investment	(21,821)	(21,524)	(21,227)	(20,930)	(20,633)	(20,335)	(126,470)	(257,980)		(257,980)
12 Scherer Discharge Pipeline-Capital	5,101	5,091	5,080	5,070	5,059	5,049	30,450	61,280	56,566	4,714
17b Disposal of Noncontainerized Liquid Waste-Capital	0	0	0	0	0	0	0	0	0	0
20 Wastewater Discharge Elimination &Reuse	19,659	19,625	19,591	19,557	19,524	19,490	117,446	236,106	217,944	18,162
21 St. Lucie Turtle Net	9,569	9,566	9,563	9,560	9,556	9,553	57,367	114,621	105,804	8,817
22 Pipeline Integrity Management	0	0	0	0	0	0	0	0	0	0
23 SPCC - Spill Prevention, Control & Countermeasures	222,302	221,806	221,309	220,812	220,315	219,818	1,326,362	2,669,799	2,464,430	205,369
24 Manatee Reburn	383,391	382,276	381,162	380,047	378,933	377,818	2,283,627	4,608,575		4,608,575
25 Pt. Everglades ESP Technology	928,899	927,444	926,811	926,309	924,234	922,017	5,555,714	11,174,199		11,174,199
26 UST Removal / Replacement	5,452	5,442	5,432	5,421	5,411	5,401	32,559	65,487	60,450	5,037
31 CAIR Compliance	1,929,369	2,044,923	2,130,548	2,216,239	2,328,752	2,572,022	13,221,853	22,192,708	20,485,577	1,707,131
33 CAMR Compliance	563,051	616,551	665,714	699,759	724,518	792,269	4,061,862	6,595,264	6,087,936	507,328
34 St. Lucie Cooling Water System Inspection & Maintenance	0	0	0	0	0	0	0	0	0	0
35 Martin Plant Drinking Water System Compliance	2,493	2,490	2,487	2,484	2,480	2,477	14,911	28,162	25,996	2,166
36 Low-Level Radioactive Waste Storage	0	0	0	0	0	27,338	27,338	27,338	25,235	2,103
37 DeSoto Next Generation Solar Energy Center	1,162,769	1,228,417	1,265,452	1,302,500	1,535,359	1,774,010	8,268,507	10,870,525	10,034,331	836,194
38 Space Coast Next Generation Solar Energy Center	90,710	121,780	148,243	159,683	171,367	235,710	927,493	1,357,538	1,253,112	104,426
39 Martin Next Generation Solar Energy Center	445,426	641,190	895,664	1,185,111	1,500,179	1,823,894	6,491,464	7,483,394	6,907,748	575,646
41 Manatee Temporary Heating System Project	0	0	0	0	0	22,849	22,849	22,849	21,091	1,758
42 Turkey Point Cooling Canal Monitoring Plan	0	0	0	0	0	0	0	0	0	0
2 Total Investment Projects - Recoverable Costs	$6,038,388	$6,496,564	$6,946,213	$7,401,102	$8,093,711	$9,078,054	$44,054,032	$ 70,756,147	$49,374,412	$21,381,735
3 Recoverable Costs Allocated to Energy	$1,789,384	$1,821,868	$1,854,457	$1,887,568	$1,937,514	$2,009,868	$11,300,660	$ 21,381,735		
4 Recoverable Costs Allocated to Demand	$4,249,004	$4,674,696	$5,091,756	$5,513,534	$6,156,197	$7,068,186	$32,753,372	$ 49,374,412		
5 Retail Energy Jurisdictional Factor	98.69261%	98.69261%	98.69261%	98.69261%	98.69261%	98.69261%				
6 Retail Demand Jurisdictional Factor	98.76729%	98.76729%	98.76729%	98.76729%	98.76729%	98.76729%				
7 Jurisdictional Energy Recoverable Costs (B)	$1,765,990	$1,798,049	$1,830,212	$1,862,890	$1,912,184	$1,983,592	$11,152,917	$ 21,102,195		
8 Jurisdictional Demand Recoverable Costs (C)	$4,196,626	$4,617,071	$5,028,989	$5,445,568	$6,080,309	$6,981,055	$32,349,618	$ 48,765,769		
9 Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$5,962,616	$6,415,120	$6,859,201	$7,308,458	$7,992,493	$8,964,647	$43,502,535	$ 69,867,964		

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

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

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		$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)	$17,321,183	17,321,183	17,321,183	17,321,183	17,321,183	17,321,183	17,321,183	n/a
3.	Less: Accumulated Depreciation (C)	$14,740,333	14,784,871	14,829,410	14,873,949	14,918,488	14,963,027	15,007,566	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$2,580,850	$2,536,311	$2,491,773	$2,447,234	$2,402,695	$2,358,156	$2,313,617	n/a
6.	Average Net Investment		2,558,581	2,514,042	2,469,503	2,424,964	2,380,425	2,335,887	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		19,661	19,318	18,976	18,634	18,292	17,949	$112,830
	b. Debt Component (Line 6 x 1.8767% x 1/12)		4,001	3,932	3,862	3,792	3,723	3,653	$22,963
8.	Investment Expenses								
	a. Depreciation (E)		44,539	44,539	44,539	44,539	44,539	44,539	$267,233
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$68,201	$67,789	$67,377	$66,965	$66,553	$66,141	$403,026

Notes:
(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

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		$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)	$17,321,183	17,321,183	17,321,183	17,321,183	17,321,183	17,321,183	17,321,183	n/a
3.	Less: Accumulated Depreciation (C)	$15,007,566	15,052,105	15,096,643	15,141,182	15,185,721	15,230,260	15,274,799	n/a
4	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$2,313,617	$2,269,078	$2,224,539	$2,180,001	$2,135,462	$2,090,923	$2,046,384	n/a
6.	Average Net Investment		2,291,348	2,246,809	2,202,270	2,157,731	2,113,192	2,068,654	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		17,607	17,265	16,923	16,580	16,238	15,896	213,339
	b. Debt Component (Line 6 x 1.8767% x 1/12)		3,583	3,514	3,444	3,374	3,305	3,235	43,419
8.	Investment Expenses								
	a. Depreciation (E)		44,539	44,539	44,539	44,539	44,539	44,539	534,466
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$65,729	$65,317	$64,906	$64,494	$64,082	$63,670	$791,224

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Notes:

(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$39	$0	($877)	($0)	$0	$0	($838)
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$11,867,699	11,867,738	11,867,738	11,866,861	11,866,861	11,866,861	11,866,861	n/a
3.	Less: Accumulated Depreciation (C)	$6,665,126	6,698,105	6,731,085	6,764,064	6,797,043	6,830,022	6,863,000	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$5,202,573	$5,169,632	$5,136,652	$5,102,796	$5,069,817	$5,036,839	$5,003,860	n/a
6.	Average Net Investment		5,186,102	5,153,142	5,119,724	5,086,307	5,053,328	5,020,350	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		39,851	39,598	39,341	39,084	38,831	38,577	$235,281
	b. Debt Component (Line 6 x 1.8767% x 1/12)		8,111	8,059	8,007	7,954	7,903	7,851	$47,885
8.	Investment Expenses								
	a. Depreciation (E)		32,980	32,980	32,979	32,979	32,979	32,979	$197,875
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$80,941	$80,636	$80,327	$80,017	$79,712	$79,407	$481,041

Notes:

(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$15,322	$14,484
	c. Retirements		-	$0	$0	$0	$0	$0	$0
	d. Other (A)		-	-	-	-	-	-	
2.	Plant-In-Service/Depreciation Base (B)	$11,866,861	11,866,861	11,866,861	11,866,861	11,866,861	11,866,861	11,882,183	n/a
3.	Less: Accumulated Depreciation (C)	$6,863,000	6,895,979	6,928,957	6,961,936	6,994,915	7,027,893	7,060,907	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$5,003,860	$4,970,882	$4,937,903	$4,904,925	$4,871,946	$4,838,967	$4,821,276	n/a
6.	Average Net Investment		4,987,371	4,954,392	4,921,414	4,888,435	4,855,457	4,830,122	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		38,324	38,070	37,817	37,564	37,310	37,115	461,481
	b. Debt Component (Line 6 x 1.8767% x 1/12)		7,800	7,748	7,697	7,645	7,593	7,554	93,922
8.	Investment Expenses								
	a. Depreciation (E)		32,979	32,979	32,979	32,979	32,979	33,013	395,781
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$79,102	$78,797	$78,492	$78,187	$77,882	$77,683	$951,184

Notes:

(A) Reserve Transfer
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

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		$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)	$58,866	58,866	58,866	58,866	58,866	58,866	58,866	n/a
3.	Less: Accumulated Depreciation (C)	$36,910	37,021	37,132	37,243	37,354	37,464	37,575	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$21,955	$21,845	$21,734	$21,623	$21,512	$21,401	$21,291	n/a
6.	Average Net Investment		21,900	21,789	21,678	21,568	21,457	21,346	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		168	167	167	166	165	164	$997
	b. Debt Component (Line 6 x 1.8767% x 1/12)		34	34	34	34	34	33	$203
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)		$313	$312	$311	$310	$309	$308	$1,865

Notes:
(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

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		$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)	$58,866	58,866	58,866	58,866	58,866	58,866	58,866	n/a
3.	Less: Accumulated Depreciation (C)	$37,575	37,686	37,797	37,908	38,018	38,129	38,240	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$21,291	$21,180	$21,069	$20,958	$20,847	$20,737	$20,626	n/a
6.	Average Net Investment		21,235	21,124	21,014	20,903	20,792	20,681	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		163	162	161	161	160	159	1,963
	b. Debt Component (Line 6 x 1.8767% x 1/12)		33	33	33	33	33	32	400
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)		$307	$306	$305	$304	$303	$302	$3,692

Notes:
(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$91,203	$3,469	$6	$94,678
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$13,550,217	13,550,217	13,550,217	13,550,217	13,641,420	13,644,889	13,644,895	n/a
3.	Less: Accumulated Depreciation (C)	$3,258,267	3,302,313	3,346,360	3,390,406	3,434,609	3,478,973	3,523,343	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5	Net Investment (Lines 2 - 3 + 4)	$10,291,951	$10,247,904	$10,203,858	$10,159,811	$10,206,812	$10,165,917	$10,121,553	n/a
6.	Average Net Investment		10,269,927	10,225,881	10,181,834	10,183,311	10,186,364	10,143,735	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		78,916	78,577	78,239	78,250	78,274	77,946	$470,202
	b. Debt Component (Line 6 x 1.8767% x 1/12)		16,061	15,992	15,923	15,926	15,930	15,864	$95,697
8.	Investment Expenses								
	a. Depreciation (E)		44,046	44,046	44,046	44,202	44,364	44,370	$265,076
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$139,023	$138,616	$138,209	$138,378	$138,568	$138,180	$830,975

Notes:

(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$45,000	$139,678
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$13,644,895	13,644,895	13,644,895	13,644,895	13,644,895	13,644,895	13,689,895	n/a
3.	Less: Accumulated Depreciation (C)	$3,523,343	3,567,713	3,612,083	3,656,452	3,700,822	3,745,192	3,789,827	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$10,121,553	$10,077,183	$10,032,813	$9,988,443	$9,944,073	$9,899,703	$9,900,069	n/a
6.	Average Net Investment		10,099,368	10,054,998	10,010,628	9,966,258	9,921,888	9,899,886	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		77,605	77,264	76,923	76,582	76,241	76,072	930,891
	b. Debt Component (Line 6 x 1.8767% x 1/12)		15,794	15,725	15,656	15,586	15,517	15,482	189,457
8.	Investment Expenses								
	a. Depreciation (E)		44,370	44,370	44,370	44,370	44,370	44,634	531,560
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$137,770	$137,359	$136,949	$136,539	$136,128	$136,189	$1,651,908

Notes:

(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

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		$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)	$31,030	31,030	31,030	31,030	31,030	31,030	31,030	n/a
3.	Less: Accumulated Depreciation (C)	$20,526	20,557	20,588	20,619	20,650	20,682	20,713	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$10,504	$10,473	$10,442	$10,411	$10,380	$10,349	$10,317	n/a
6.	Average Net Investment		10,488	10,457	10,426	10,395	10,364	10,333	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		81	80	80	80	80	79	$480
	b. Debt Component (Line 6 x 1.8767% x 1/12)		16	16	16	16	16	16	$98
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)		$128	$128	$127	$127	$127	$127	$764

Notes:
(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

21

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

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		$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)	$31,030	31,030	31,030	31,030	31,030	31,030	31,030	n/a
3.	Less: Accumulated Depreciation (C)	$20,713	20,744	20,775	20,806	20,837	20,868	20,899	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$10,317	$10,286	$10,255	$10,224	$10,193	$10,162	$10,131	n/a
6.	Average Net Investment		10,302	10,271	10,240	10,209	10,178	10,147	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		79	79	79	78	78	78	951
	b. Debt Component (Line 6 x 1.8767% x 1/12)		16	16	16	16	16	16	194
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)		$126	$126	$126	$125	$125	$125	$1,517

Notes:
(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		($53,550)	$0	$0	$0	$14,017	$17,141	($22,392)
	c. Retirements		($53,550)	$0	$0	$0	$0	$0	($53,550)
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$470,285	416,735	416,735	416,735	416,735	430,752	447,893	n/a
3.	Less: Accumulated Depreciation (C)	$213,218	164,497	169,327	174,162	178,991	183,937	189,142	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$257,067	$252,238	$247,409	$242,574	$237,745	$246,815	$258,751	n/a
6.	Average Net Investment		254,653	249,823	244,991	240,159	242,280	252,783	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		1,957	1,920	1,883	1,845	1,862	1,942	$11,409
	b. Debt Component (Line 6 x 1.8767% x 1/12)		398	391	383	376	379	395	$2,322
8.	Investment Expenses								
	a. Depreciation (E)		4,829	4,829	4,835	4,829	4,946	5,205	$29,474
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$7,184	$7,140	$7,101	$7,050	$7,186	$7,543	$43,204

Notes:
(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

23

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

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		$0	$0	$0	$0	$0	$0	$0
b.	Clearings to Plant		$56,000	$22,632	$0	$14,643	$0	$59,500	$130,382
c.	Retirements		$0	($5,368)	$0	($13,357)	$0	$0	($72,276)
d.	Other (A)								0
2.	Plant-In-Service/Depreciation Base (B)	$447,893	503,893	526,524	526,524	541,167	541,167	600,667	n/a
3.	Less: Accumulated Depreciation (C)	$189,142	194,719	195,192	200,983	193,567	199,741	206,270	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$258,751	$309,174	$331,332	$325,542	$347,600	$341,426	$394,397	n/a
6.	Average Net Investment		283,962	320,253	328,437	336,571	344,513	367,912	n/a
7.	Return on Average Net Investment								
a.	Equity Component grossed up for taxes (D)		2,182	2,461	2,524	2,586	2,647	2,827	26,636
b.	Debt Component (Line 6 x 1.8767% x 1/12)		444	501	514	526	539	575	5,421
8.	Investment Expenses								
a.	Depreciation (E)		5,577	5,842	5,790	5,941	6,174	6,529	65,327
b.	Amortization (F)								
c.	Dismantlement								
d.	Property Expenses								
e.	Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$8,203	$8,803	$8,828	$9,054	$9,361	$9,931	$97,384

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

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		$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)	$117,794	117,794	117,794	117,794	117,794	117,794	117,794	n/a
3.	Less: Accumulated Depreciation (C)	$47,336	47,474	47,611	47,749	47,886	48,023	48,161	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$70,458	$70,320	$70,183	$70,045	$69,908	$69,770	$69,633	n/a
6.	Average Net Investment		70,389	70,251	70,114	69,977	69,839	69,702	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		541	540	539	538	537	536	$3,229
	b. Debt Component (Line 6 x 1.8767% x 1/12)		110	110	110	109	109	109	$657
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)		$788	$787	$786	$785	$783	$782	$4,711

Notes:

(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

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		$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)	$117,794	117,794	117,794	117,794	117,794	117,794	117,794	n/a
3. Less: Accumulated Depreciation (C)	$48,161	48,298	48,436	48,573	48,710	48,848	48,985	n/a
4. CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5. Net Investment (Lines 2 - 3 + 4)	$69,633	$69,496	$69,358	$69,221	$69,083	$68,946	$68,809	n/a
6. Average Net Investment		69,564	69,427	69,289	69,152	69,015	68,877	n/a
7. Return on Average Net Investment								
a. Equity Component grossed up for taxes (D)		535	533	532	531	530	529	6,421
b. Debt Component (Line 6 x 1.8767% x 1/12)		109	109	108	108	108	108	1,307
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)		$781	$779	$778	$777	$776	$774	$9,377

Notes:
(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

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		$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)	$864,260	864,260	864,260	864,260	864,260	864,260	864,260	n/a
3.	Less: Accumulated Depreciation (C)	$428,372	429,510	430,649	431,788	432,927	434,065	435,204	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$435,889	$434,750	$433,611	$432,473	$431,334	$430,195	$429,056	n/a
6.	Average Net Investment		435,319	434,181	433,042	431,903	430,764	429,626	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,345	3,336	3,328	3,319	3,310	3,301	$19,939
	b. Debt Component (Line 6 x 1.8767% x 1/12)		681	679	677	675	674	672	$4,058
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)		$5,165	$5,154	$5,144	$5,133	$5,122	$5,112	$30,830

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 42-8E, pages 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

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		$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)	$864,260	864,260	864,260	864,260	864,260	864,260	864,260	n/a
3.	Less: Accumulated Depreciation (C)	$435,204	436,343	437,482	438,620	439,759	440,898	442,037	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$429,056	$427,918	$426,779	$425,640	$424,501	$423,363	$422,224	n/a
6	Average Net Investment		428,487	427,348	426,209	425,071	423,932	422,793	n/a
7.	Return on Average Net Investment								
	a. *Equity Component grossed up for taxes (D)*		3,293	3,284	3,275	3,266	3,258	3,249	39,563
	b. Debt Component (Line 6 x 1.8767% x 1/12)		670	668	667	665	663	661	8,052
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)		$5,101	$5,091	$5,080	$5,070	$5,059	$5,049	$61,280

Notes:
(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

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		$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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

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		$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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Wastewater/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		$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)	$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)	$606,781	610,430	614,079	617,727	621,376	625,025	628,673	n/a
4.	*CWIP - Non Interest Bearing*	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,754,881	$1,751,232	$1,747,583	$1,743,935	$1,740,286	$1,736,637	$1,732,988	n/a
6.	Average Net Investment		1,753,056	1,749,408	1,745,759	1,742,110	1,738,461	1,734,813	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		13,471	13,443	13,415	13,387	13,359	13,331	$80,404
	b. Debt Component (Line 6 x 1.8767% x 1/12)		2,742	2,736	2,730	2,724	2,719	2,713	$16,364
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)		$19,861	$19,827	$19,794	$19,760	$19,726	$19,692	$118,660

Notes:

(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Wastewater/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		$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)	$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)	$628,673	632,322	635,971	639,620	643,268	646,917	650,566	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,732,988	$1,729,340	$1,725,691	$1,722,042	$1,718,393	$1,714,745	$1,711,096	n/a
6.	Average Net Investment		1,731,164	1,727,515	1,723,867	1,720,218	1,716,569	1,712,920	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		13,303	13,275	13,246	13,218	13,190	13,162	159,799
	b. Debt Component (Line 6 x 1.8767% x 1/12)		2,707	2,702	2,696	2,690	2,685	2,679	32,523
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)		$19,659	$19,625	$19,591	$19,557	$19,524	$19,490	$236,106

Notes:

(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$34,917	$881	$1,257	($125)	$0	$0	$36,929
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$249,320	284,237	285,117	286,374	286,249	286,249	286,249	n/a
3.	Less: Accumulated Depreciation (C)	($714,470)	(714,159)	(713,827)	(713,493)	(713,159)	(712,825)	(712,491)	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$963,790	$998,395	$998,944	$999,867	$999,408	$999,074	$998,740	n/a
6.	Average Net Investment		981,093	998,670	999,405	999,638	999,241	998,907	n/a
7.	*Return on Average Net Investment*								
	a. Equity Component grossed up for taxes (D)		7,539	7,674	7,680	7,681	7,678	7,676	$45,928
	b. Debt Component (Line 6 x 1.8767% x 1/12)		1,534	1,562	1,563	1,563	1,563	1,562	$9,347
8.	Investment Expenses								
	a. Depreciation (E)		311	332	333	334	334	334	$1,979
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$9,384	$9,568	$9,576	$9,579	$9,575	$9,572	$57,254

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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$36,829
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$286,249	286,249	286,249	286,249	286,249	286,249	286,249	n/a
3.	Less: Accumulated Depreciation (C)	($712,491)	(712,157)	(711,823)	(711,490)	(711,156)	(710,822)	(710,488)	n/a
4.	*CWIP - Non Interest Bearing*	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$998,740	$998,406	$998,072	$997,738	$997,405	$997,071	$996,737	n/a
6.	Average Net Investment		998,573	998,239	997,905	997,572	997,238	996,904	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		7,673	7,671	7,668	7,666	7,663	7,660	91,929
	b. Debt Component (Line 6 x 1.8767% x 1/12)		1,562	1,561	1,561	1,560	1,560	1,559	18,710
8.	Investment Expenses								
	a. Depreciation (E)		334	334	334	334	334	334	3,982
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$9,569	$9,566	$9,563	$9,560	$9,556	$9,553	$114,621

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

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		$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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

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		$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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

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		$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$10,183	$18,645	$11,218	($11)	$1,402	$2	$41,439
c. Retirements		$0	$0	$0	$0	$0	$0	$0
d. Other (A)								
2. Plant-In-Service/Depreciation Base (B)	$20,603,335	20,613,519	20,632,164	20,643,381	20,643,370	20,644,772	20,644,774	n/a
3. Less: Accumulated Depreciation (C)	$2,068,022	2,121,685	2,175,280	2,229,015	2,282,756	2,336,492	2,390,224	n/a
4. CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5. Net Investment (Lines 2 - 3 + 4)	$18,535,314	$18,491,834	$18,456,884	$18,414,367	$18,360,615	$18,308,280	$18,254,550	n/a
6. Average Net Investment		18,513,574	18,474,359	18,435,625	18,387,491	18,334,447	18,281,415	n/a
7. Return on Average Net Investment								
a. Equity Component grossed up for taxes (D)		142,261	141,960	141,662	141,293	140,885	140,477	$848,539
b. Debt Component (Line 6 x 1.8767% x 1/12)		28,953	28,892	28,831	28,756	28,673	28,590	$172,697
8. Investment Expenses								
a. Depreciation (E)		53,663	53,595	53,735	53,741	53,736	53,732	$322,202
b. Amortization (F)								
c. Dismantlement								
d. Property Expenses								
e. Other (G)								
9. Total System Recoverable Expenses (Lines 7 & 8)		$224,878	$224,447	$224,229	$223,790	$223,294	$222,799	$1,343,438

Notes:

(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$41,439
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$20,644,774	20,644,774	20,644,774	20,644,774	20,644,774	20,644,774	20,644,774	n/a
3.	Less: Accumulated Depreciation (C)	$2,390,224	2,443,955	2,497,687	2,551,418	2,605,150	2,658,882	2,712,613	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$18,254,550	$18,200,819	$18,147,087	$18,093,356	$18,039,624	$17,985,892	$17,932,161	n/a
6.	Average Net Investment		18,227,685	18,173,953	18,120,221	18,066,490	18,012,758	17,959,027	n/a
7.	*Return on Average Net Investment*								
	a. Equity Component grossed up for taxes (D)		140,065	139,652	139,239	138,826	138,413	138,000	1,682,733
	b. Debt Component (Line 6 x 1.8767% x 1/12)		28,506	28,422	28,338	28,254	28,170	28,086	342,474
8.	Investment Expenses								
	a. Depreciation (E)		53,732	53,732	53,732	53,732	53,732	53,732	644,592
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$222,302	$221,806	$221,309	$220,812	$220,315	$219,818	$2,669,799

Notes:
(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

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		$0	$0	$0	$0	$0	($63,821)	($63,821)
	c. Retirements		$0	$0	$0	$0	$0	($63,821)	($63,821)
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$32,862,568	32,862,568	32,862,568	32,862,568	32,862,568	32,862,568	32,798,747	n/a
3.	Less: Accumulated Depreciation (C)	$3,652,607	3,773,330	3,894,053	4,014,776	4,135,499	4,256,221	4,313,017	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$29,209,961	$29,089,238	$28,968,515	$28,847,793	$28,727,070	$28,606,347	$28,485,731	n/a
6.	Average Net Investment		29,149,599	29,028,877	28,908,154	28,787,431	28,666,708	28,546,039	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		223,990	223,063	222,135	221,207	220,280	219,353	$1,330,028
	b. Debt Component (Line 6 x 1.8767% x 1/12)		45,587	45,398	45,209	45,021	44,832	44,643	$270,690
8.	Investment Expenses								
	a. Depreciation (E)		120,723	120,723	120,723	120,723	120,723	120,616	$724,230
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$390,300	$389,184	$388,067	$386,951	$385,834	$384,612	$2,324,949

Notes:

(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

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	($63,821)
	c. Retirements		$0	$0	$0	$0	$0	$0	($63,821)
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$32,798,747	32,798,747	32,798,747	32,798,747	32,798,747	32,798,747	32,798,747	n/a
3.	Less: Accumulated Depreciation (C)	$4,313,017	4,433,527	4,554,037	4,674,547	4,795,057	4,915,567	5,036,077	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$28,485,731	$28,365,221	$28,244,711	$28,124,200	$28,003,690	$27,883,180	$27,762,670	n/a
6.	Average Net Investment		28,425,476	28,304,966	28,184,456	28,063,945	27,943,435	27,822,925	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		218,426	217,500	216,574	215,648	214,722	213,796	2,626,694
	b. Debt Component (Line 6 x 1.8767% x 1/12)		44,455	44,266	44,078	43,889	43,701	43,512	534,591
8.	Investment Expenses								
	a. Depreciation (E)		120,510	120,510	120,510	120,510	120,510	120,510	1,447,290
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$383,391	$382,276	$381,162	$380,047	$378,933	$377,818	$4,608,576

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

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		$651	($651)	$0	$0	$9,607	$29,127	$38,733
	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)	$81,392,396	81,392,396	81,392,396	81,392,396	81,392,396	81,392,396	81,392,396	n/a
3.	Less: Accumulated Depreciation (C)	$9,119,828	9,395,463	9,671,097	9,946,731	10,222,366	10,498,000	10,773,634	n/a
4.	CWIP - Non Interest Bearing	$0	651	0	0	0	9,607	38,733	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$72,272,568	$71,997,585	$71,721,299	$71,445,665	$71,170,031	$70,904,003	$70,657,495	n/a
6.	Average Net Investment		72,135,076.40	71,859,442	71,583,482	71,307,848	71,037,017	70,780,749	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		554,298.02	552,180	550,059	547,941	545,860	543,891	$3,294,230
	b. Debt Component (Line 6 x 1.8767% x 1/12)		112,812	112,381	111,949	111,518	111,095	110,694	$670,450
8.	Investment Expenses								
	a. Depreciation (E)		275,634	275,634	275,634	275,634	275,634	275,634	$1,653,806
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$942,744.42	$940,195.33	$937,643.24	$935,094.15	$932,589.49	$930,219.51	$5,618,486.14

Notes:
(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

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)	$492,916	492,916	492,916	492,916	492,916	492,916	492,916	n/a
3.	Less: Accumulated Depreciation (C)	$16,081	17,190	18,299	19,409	20,518	21,627	22,736	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$476,835	$475,726	$474,617	$473,508	$472,399	$471,290	$470,181	n/a
6.	Average Net Investment		476,281	475,171	474,062	472,953	471,844	470,735	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,660	3,651	3,643	3,634	3,626	3,617	$21,831
	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)		1,109	1,109	1,109	1,109	1,109	1,109	$6,654
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$5,514	$5,503	$5,493	$5,483	$5,473	$5,462	$32,929

Notes:
(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

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)	$492,916	492,916	492,916	492,916	492,916	492,916	492,916	n/a
3. Less: Accumulated Depreciation (C)	$22,736	23,845	24,954	26,063	27,172	28,281	29,390	n/a
4. CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5. Net Investment (Lines 2 - 3 + 4)	$470,181	$469,072	$467,963	$466,854	$465,744	$464,635	$463,526	n/a
6. Average Net Investment		469,626	468,517	467,408	466,299	465,190	464,081	n/a
7. Return on Average Net Investment								
a. Equity Component grossed up for taxes (D)		3,609	3,600	3,592	3,583	3,575	3,566	43,355
b. Debt Component (Line 6 x 1.8767% x 1/12)		734	733	731	729	728	726	8,824
8. Investment Expenses								
a. Depreciation (E)		1,109	1,109	1,109	1,109	1,109	1,109	13,309
b. Amortization (F)								
c. Dismantlement								
d. Property Expenses								
e. Other (G)								
9. Total System Recoverable Expenses (Lines 7 & 8)		$5,452	$5,442	$5,432	$5,421	$5,411	$5,401	$65,488

Notes:
(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

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		$7,945,731	$6,640,920	$9,158,137	$11,769,312	$9,782,522	$7,921,002	$53,217,623
	b. Clearings to Plant		$8,224	($19,541)	$26,593,750	$137,346	$18,532,803	$1,638,837	$46,891,420
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$18,552,866	18,561,089	18,541,549	45,135,299	45,272,645	63,805,448	65,444,286	n/a
3.	Less: Accumulated Depreciation (C)	($46,278)	(20,582)	5,103	43,073	119,892	224,972	360,239	n/a
4.	CWIP - Non Interest Bearing	$109,227,814	117,173,545	123,814,465	106,390,427	118,159,739	112,849,570	120,562,105	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$127,826,958	$135,755,217	$142,350,911	$151,482,654	$163,312,492	$176,430,046	$185,646,152	n/a
6.	Average Net Investment		131,791,087	139,053,064	146,916,782	157,397,573	169,871,269	181,038,099	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		1,012,705	1,068,507	1,128,933	1,209,469	1,305,319	1,391,127	$7,116,061
	b. Debt Component (Line 6 x 1.8767% x 1/12)		206,108	217,465	229,763	246,154	265,662	283,125	$1,448,278
8.	Investment Expenses								
	a. Depreciation (E)		25,696	25,685	37,970	76,819	105,080	135,266	$406,517
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,244,509	$1,311,657	$1,396,666	$1,532,443	$1,676,061	$1,809,519	$8,970,855

Notes:
(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

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		$10,964,925	$8,866,055	$9,890,581	$8,829,794	$14,253,335	$36,297,893	$142,320,206
	b. Clearings to Plant		$27,348,674	$150,000	$234,491	$303,230	$13,342,902	$6,910,968	$95,181,684
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$65,444,286	92,792,959	92,942,959	93,177,450	93,480,680	106,823,582	113,734,550	n/a
3.	Less: Accumulated Depreciation (C)	$360,239	522,789	710,815	899,477	1,089,015	1,286,116	1,494,613	n/a
4.	CWIP - Non Interest Bearing	$120,562,105	104,178,357	112,894,412	122,550,502	131,077,066	131,987,499	161,374,424	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$185,646,152	$196,448,527	$205,126,556	$214,828,475	$223,468,731	$237,524,965	$273,614,361	n/a
6.	Average Net Investment		191,047,339	200,787,541	209,977,515	219,148,603	230,496,848	255,569,663	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		1,468,040	1,542,885	1,613,502	1,683,975	1,771,176	1,963,840	17,159,479
	b. Debt Component (Line 6 x 1.8767% x 1/12)		298,779	314,012	328,384	342,727	360,474	399,685	3,492,338
8.	Investment Expenses								
	a. Depreciation (E)		162,550	188,026	188,662	189,538	197,101	208,497	1,540,891
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,929,369	$2,044,923	$2,130,548	$2,216,239	$2,328,752	$2,572,022	$22,192,708

Notes:

(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

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		($5,605,392)	$3,569,698	$3,701,516	$4,896,391	$1,942,766	$7,040,301	$15,545,280
	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	$42,845,645	37,240,253	40,809,951	44,511,467	49,407,858	51,350,624	58,390,925	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$42,845,645	$37,240,253	$40,809,951	$44,511,467	$49,407,858	$51,350,624	$58,390,925	n/a
6.	Average Net Investment		40,042,949	39,025,102	42,660,709	46,959,662	50,379,241	54,870,774	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		307,697	299,875	327,812	360,846	387,123	421,636	$2,104,989
	b. Debt Component (Line 6 x 1.8767% x 1/12)		62,623	61,031	66,717	73,440	78,788	85,812	$428,412
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)		$370,320	$360,907	$394,529	$434,286	$465,911	$507,449	$2,533,401

Notes:

(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

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		$4,984,422	$6,585,495	$4,046,620	$3,315,863	$2,038,575	$12,613,412	$49,129,667
	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	$58,390,925	63,375,347	69,960,842	74,007,462	77,323,325	79,361,900	91,975,312	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$58,390,925	$63,375,347	$69,960,842	$74,007,462	$77,323,325	$79,361,900	$91,975,312	n/a
6.	Average Net Investment		60,883,136	66,668,094	71,984,152	75,665,393	78,342,612	85,668,606	n/a
7	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		467,836	512,289	553,138	581,426	601,998	658,292	5,479,967
	b. Debt Component (Line 6 x 1.8767% x 1/12)		95,215	104,262	112,576	118,333	122,520	133,977	1,115,296
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)		$563,051	$616,551	$665,714	$699,759	$724,518	$792,269	$6,595,263

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 42-8E, pages 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project:St. Lucie Cooling Water System Inspection (Project No. 34)
(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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project:St. Lucie Cooling Water System Inspection (Project No. 34)
(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	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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project:Martin Water Comp (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		$187,280	$48,134	$15	($10)	$0	$0	$235,419
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	187,280	235,414	235,429	235,419	235,419	235,419	n/a
3.	Less: Accumulated Depreciation (C)	$0	133	432	766	1,099	1,433	1,766	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$187,147	$234,982	$234,664	$234,320	$233,986	$233,653	n/a
6.	Average Net Investment		93,574	211,064	234,823	234,492	234,153	233,820	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		719	1,622	1,804	1,802	1,799	1,797	$9,543
	b. Debt Component (Line 6 x 1.8767% x 1/12)		146	330	367	367	366	366	$1,942
8.	Investment Expenses								
	a. Depreciation (E)		133	299	334	334	334	334	$1,766
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$998	$2,251	$2,505	$2,502	$2,499	$2,496	$13,251

Notes:
(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project:Martin Water Comp (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	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$235,419
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$235,419	235,419	235,419	235,419	235,419	235,419	235,419	n/a
3.	Less: Accumulated Depreciation (C)	$1,766	2,100	2,433	2,767	3,100	3,434	3,767	n/a
4.	*CWIP - Non Interest Bearing*	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$233,653	$233,319	$232,986	$232,652	$232,319	$231,985	$231,652	n/a
6.	Average Net Investment		233,486	233,153	232,819	232,486	232,152	231,819	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		1,794	1,792	1,789	1,786	1,784	1,781	20,270
	b. Debt Component (Line 6 x 1.8767% x 1/12)		365	365	364	364	363	363	4,125
8.	Investment Expenses								
	a. Depreciation (E)		334	334	334	334	334	334	3,767
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$2,493	$2,490	$2,487	$2,484	$2,480	$2,477	$28,162

Notes:
(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Low Level Rad Waste - LLW (Project No. 36)
(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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Low Level Rad Waste - LLW (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	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$5,288,004	$5,288,004
	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	5,288,004	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	2,900	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	$5,285,104	n/a
6.	Average Net Investment		0	0	0	0	0	2,642,552	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	20,306	20,306
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	4,133	4,133
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	2,900	2,900
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$27,338	$27,338

Notes:

(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Desoto Next Generation Solar Energy Center (Project No. 37)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		3,450,325.11	2,850,340.03	45,006,487.49	13,019,436.54	15,552,199.01	39,479,397.28	$119,358,185
	b. Clearings to Plant		$0	$0	$0	$0	$0	$1,001,475	$1,001,475
	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	1,001,475	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	1,333	n/a
4.	CWIP - Non Interest Bearing	$2,709,254	6,159,579	9,009,919	54,016,407	67,035,843	82,588,042	121,098,523	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$2,709,254	$6,159,579	$9,009,919	$54,016,407	$67,035,843	$82,588,042	$122,098,664	n/a
6.	Average Net Investment		4,434,417	7,584,749	31,513,163	60,526,125	74,811,943	102,343,353	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		34,075	58,282	242,152	465,093	574,868	786,423	$2,160,894
	b. Debt Component (Line 6 x 1.8767% x 1/12)		6,935	11,862	49,283	94,657	116,998	160,055	$439,790
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	1,333	$1,333
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$41,010	$70,144	$291,436	$559,750	$691,866	$947,812	$2,602,017

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 42-8E, pages 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Desoto Next Generation Solar Energy Center (Project No. 37)
(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		$6,690,596	$7,511,983	$502,509	$7,514,860	$330,971	$7,069,820	$148,978,924
	b. Clearings to Plant		$0	$0	$0	$0	$143,649,442	$7,069,820	$151,720,737
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$1,001,475	1,001,475	1,001,475	1,001,475	1,001,475	144,650,917	151,720,737	n/a
3.	Less: Accumulated Depreciation (C)	$1,333	4,000	6,667	9,334	12,001	212,186	619,610	n/a
4.	CWIP - Non Interest Bearing	$121,096,523	127,789,119	135,301,102	135,803,611	143,318,471	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$122,096,664	$128,786,593	$136,295,910	$136,795,752	$144,307,945	$144,438,731	$151,101,127	n/a
6.	Average Net Investment		125,442,629	132,541,251	136,545,831	140,551,848	144,373,338	147,769,929	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		963,922	1,018,469	1,049,241	1,080,024	1,109,389	1,135,489	8,517,426
	b. Debt Component (Line 6 x 1.8767% x 1/12)		196,180	207,281	213,544	219,809	225,785	231,097	1,733,487
8.	Investment Expenses								
	a. Depreciation (E)		2,667	2,667	2,667	2,667	200,185	407,424	619,610
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,162,769	$1,228,417	$1,265,452	$1,302,500	$1,535,359	$1,774,010	$10,870,525

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Space Coast Next Generation Solar Energy Center (Project No. 38)
(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		120,791.52	30,345.74	94,890.36	1,234,283.68	98,885.64	136,871.99	$1,716,069
	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*	$7,010,918	7,131,710	7,162,056	7,256,946	8,491,230	8,590,115	8,726,987	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$7,010,918	$7,131,710	$7,162,056	$7,256,946	$8,491,230	$8,590,115	$8,726,987	n/a
6.	Average Net Investment		7,071,314	7,146,883	7,209,501	7,874,088	8,540,672	8,658,551	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		54,337	54,918	55,399	60,506	65,628	66,534	$357,322
	b. Debt Component (Line 6 x 1.8767% x 1/12)		11,059	11,177	11,275	12,314	13,357	13,541	$72,723
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)		$65,396	$66,095	$66,674	$72,820	$78,985	$80,075	$430,044

Notes:
(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Space Coast Next Generation Solar Energy Center (Project No. 38)
(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		$2,163,168	$4,555,924	$1,167,101	$1,306,805	$1,220,092	12,694,828.00	$24,823,987
	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	$8,726,987	10,890,155	15,446,079	16,613,180	17,919,985	19,140,077	31,834,905	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$8,726,987	$10,890,155	$15,446,079	$16,613,180	$17,919,985	$19,140,077	$31,834,905	n/a
6.	Average Net Investment		9,808,571	13,168,117	16,029,630	17,266,583	18,530,031	25,487,491	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		75,371	101,186	123,174	132,679	142,388	195,850	1,127,970
	b. Debt Component (Line 6 x 1.8767% x 1/12)		15,340	20,594	25,069	27,003	*28,979*	*39,860*	*229,567*
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)		$90,710	$121,780	$148,243	$159,683	$171,367	$235,710	$1,357,537

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Martin Next Generation Solar Energy Center (Project No. 39)
(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		2,393,433.16	1,012,996.46	4,213,354.01	5,368,275.57	7,896,194.98	11,587,918.38	$32,472,173
	b. Clearings to Plant		$0	$0	$0	$0	$0	$956,266	$956,266
	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	956,266	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	1,273	n/a
4.	CWIP - Non Interest Bearing	$7,267,895	9,661,329	10,674,325	14,887,679	20,255,955	28,152,150	38,755,197	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$7,267,895	$9,661,329	$10,674,325	$14,887,679	$20,255,955	$28,152,150	$39,710,191	n/a
6.	Average Net Investment		8,464,612	10,167,827	12,781,002	17,571,817	24,204,052	33,931,170	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		65,043	78,131	98,211	135,025	185,988	260,733	$823,132
	b. Debt Component (Line 6 x 1.8767% x 1/12)		13,238	15,901	19,988	27,481	37,853	53,065	$167,526
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	1,273	$1,273
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$78,281	$94,033	$118,200	$162,505	$223,841	$315,070	$991,930

Notes:

(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Martin Next Generation Solar Energy Center (Project No. 39)
(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		16,359,231.00	25,981,914.00	29,056,064.00	33,372,764.00	34,598,235.00	35,417,088.00	$207,257,469
	b. Clearings to Plant		$0	$0	$0	$350,000	$0	$0	$1,306,266
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$956,266	956,266	956,266	956,266	1,306,266	1,306,266	1,306,266	n/a
3.	Less: Accumulated Depreciation (C)	$1,273	3,823	6,373	8,923	12,275	16,429	20,583	n/a
4.	CWIP - Non Interest Bearing	$38,755,197	55,114,428	81,096,342	110,152,406	143,175,170	177,773,405	213,190,493	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$39,710,191	$56,066,872	$82,046,236	$111,099,750	$144,469,161	$179,063,242	$214,476,176	n/a
6.	Average Net Investment		47,888,531	69,056,554	96,572,993	127,784,455	161,766,202	196,769,709	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		367,984	530,642	742,083	981,917	1,243,039	1,512,011	6,200,808
	b. Debt Component (Line 6 x 1.8767% x 1/12)		74,893	107,998	151,031	199,842	252,986	307,728	1,262,003
8.	Investment Expenses								
	a. Depreciation (E)		2,550	2,550	2,550	3,352	4,154	4,154	20,583
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$445,426	$641,190	$895,664	$1,185,111	$1,500,179	$1,823,894	$7,483,394

Notes:
(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Greenhouse Gas Reduction (Project No. 40)
(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 57-60.*
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

61

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Greenhouse Gas Reduction (Project No. 40)
(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	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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Temporary Heating System (Project No. 41)
(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
	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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

63

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Temporary Heating System (Project No. 41)
(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	$4,688,928	$4,688,928
	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	4,688,928	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	1,172	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	$4,687,756	n/a
6.	Average Net Investment		0	0	0	0	0	2,343,878	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	18,011	18,011
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	3,666	3,666
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	1,172	1,172
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$22,849	$22,849

Notes:
(A) N/A
(B) 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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Turkey Point Cooling Canal Monitoring (Project No. 42)
(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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

65

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Turkey Point Cooling Canal Monitoring (Project No. 42)
(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	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 57-60.
(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 57-60.
(F) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2009

Return on Capital Investments, Depreciation and Taxes
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	Six Month 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	(2,373,406)	(2,360,548)	(2,347,689)	(2,332,675)	(2,415,164)	(2,389,698)	(2,375,545)	
2	Total Working Capital	($2,373,406)	($2,360,548)	($2,347,689)	($2,332,675)	($2,415,164)	($2,389,698)	($2,375,545)	
3	Average Net Working Capital Balance		(2,366,977)	(2,354,119)	(2,340,182)	(2,373,920)	(2,402,431)	(2,382,621)	
4	Return on Average Net Working Capital Balance								
a	Equity Component grossed up for taxes (A)		(18,188)	(18,089)	(17,982)	(18,242)	(18,461)	(18,308)	
b	Debt Component (Line 6 x 1.6698% x 1/12)		(3,702)	(3,682)	(3,660)	(3,713)	(3,757)	(3,726)	
5	Total Return Component		($21,890)	($21,771)	($21,642)	($21,954)	($22,218)	($22,035)	($131,510) (D)
6	Expense Dr (Cr)								
a	411.800 Gains from Dispositions of Allowances		(12,858)	(12,858)	(15,015)	(53,391)	(25,466)	(32,119)	
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)		($12,858)	($12,858)	($15,015)	($53,391)	($25,466)	($32,119)	($151,707) (E)
8	Total System Recoverable Expenses (Lines 5+7)		(34,748)	(34,629)	(36,657)	(75,345)	(47,684)	(54,153)	
a	Recoverable Costs Allocated to Energy		(34,748)	(34,629)	(36,657)	(75,345)	(47,684)	(54,153)	
b	Recoverable Costs Allocated to Demand		0	0	0	0	0	0	
9	Energy Jurisdictional Factor		98.69261%	98.69261%	98.69261%	98.69261%	98.69261%	98.69261%	
10	Demand Jurisdictional Factor		98.76729%	98.76729%	98.76729%	98.76729%	98.76729%	98.76729%	
11	Retail Energy-Related Recoverable Costs (B)		(34,294)	(34,176)	(36,177)	(74,360)	(47,060)	(53,445)	
12	Retail Demand-Related Recoverable Costs (C)			0	0	0	0	0	
13	Tot Applicable beginning of period and end of period depreciable base by production pl		($34,294)	($34,176)	($36,177)	($74,360)	($47,060)	($53,445)	

Notes:

(A) Applicable depreciation rate or rates. See Form 42-8E, pages 57-60.
(B) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(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 2009

Return on Capital Investments, Depreciation and Taxes
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	Twelve Month 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	($2,375,545)	(2,343,426)	(2,311,307)	(2,279,188)	(2,247,070)	(2,214,951)	(2,182,832)		
2	Total Working Capital	($2,375,545)	($2,343,426)	($2,311,307)	($2,279,188)	($2,247,070)	($2,214,951)	($2,182,832)		
3	Average Net Working Capital Balance		(2,359,485)	(2,327,366)	(2,295,248)	(2,263,129)	(2,231,010)	(2,198,891)		
4	Return on Average Net Working Capital Balance									
a	Equity Component grossed up for taxes (A)		(18,131)	(17,884)	(17,637)	(17,390)	(17,143)	(16,897)		
b	Debt Component (Line 6 x 1.6698% x 1/12)		(3,690)	(3,640)	(3,590)	(3,539)	(3,489)	(3,439)		
5	Total Return Component		($21,821)	($21,524)	($21,227)	($20,930)	($20,633)	($20,335)	($257,978)	(D)
6	Expense Dr (Cr)									
a	411.800 Gains from Dispositions of Allowances		(32,119)	(32,119)	(32,119)	(32,119)	(32,119)	(32,119)		
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)		($32,119)	($32,119)	($32,119)	($32,119)	($32,119)	($32,119)	($344,419)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		(53,939)	(53,642)	(53,345)	(53,048)	(52,751)	(52,454)		
a	Recoverable Costs Allocated to Energy		(53,939)	(53,642)	(53,345)	(53,048)	(52,751)	(52,454)		
b	Recoverable Costs Allocated to Demand		0	0	0	0	0	0		
9	Energy Jurisdictional Factor		98.69261%	98.69261%	98.69261%	98.69261%	98.69261%	98.69261%		
10	Demand Jurisdictional Factor		98.76729%	98.76729%	98.76729%	98.76729%	98.76729%	98.76729%		
11	Retail Energy-Related Recoverable Costs (B)		(53,234)	(52,941)	(52,648)	(52,355)	(52,062)	(51,768)		
12	Retail Demand-Related Recoverable Costs (C)			0	0	0	0	0		
13	Tot Applicable beginning of period and end of period depreciable base by production pl:		($53,234)	($52,941)	($52,648)	($52,355)	($52,062)	($51,768)		

Notes:
(A) Applicable depreciation rate or rates. See Form 42-8E, pages 57-60.
(B) Applicable amortization period(s). See Form 42-8E, pages 57-60.
(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.

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Florida Power & Light Company
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Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Actual Balance December 2008	Estimated Balance December 2009
02 - Low NOX Burner Technology						
	02 - Steam Generation Plant	PtEverglades U1	31200	6.70%	2,689,232.57	2,689,232.57
	02 - Steam Generation Plant	PtEverglades U2	31200	6.10%	2,368,972.27	2,368,972.27
	02 - Steam Generation Plant	Riviera U3	31200	1.70%	3,815,802.70	3,815,802.70
	02 - Steam Generation Plant	Riviera U4	31200	1.40%	3,246,925.80	3,246,925.80
	02 - Steam Generation Plant	TurkeyPt U1	31200	2.00%	2,925,027.84	2,925,027.84
	02 - Steam Generation Plant	TurkeyPt U2	31200	1.80%	2,275,221.65	2,275,221.65
02 - Low NOX Burner Technology Total					**17,321,182.83**	**17,321,182.83**
03 - Continuous Emission Monitoring						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.70%	59,227.10	59,227.10
	02 - Steam Generation Plant	CapeCanaveral Comm	31200	1.30%	44,644.65	44,644.65
	02 - Steam Generation Plant	CapeCanaveral U1	31200	1.40%	325,165.05	325,165.05
	02 - Steam Generation Plant	CapeCanaveral U2	31200	1.10%	345,150.96	345,150.96
	02 - Steam Generation Plant	CapeCanaveral U1	31100	0.00%	64,883.87	64,883.87
	02 - Steam Generation Plant	CapeCanaveral U1	31200	0.50%	36,276.52	36,276.52
	02 - Steam Generation Plant	Cutler U5	31200	0.20%	310,454.41	310,454.41
	02 - Steam Generation Plant	Cutler U6	31200	1.00%	311,861.95	311,861.95
	02 - Steam Generation Plant	Manatee Comm	31200	14.10%	31,859.00	31,859.00
	02 - Steam Generation Plant	Manatee U1	31100	4.10%	56,430.25	56,430.25
	02 - Steam Generation Plant	Manatee U1	31200	4.80%	462,142.42	462,142.42
	02 - Steam Generation Plant	Manatee U2	31100	4.10%	56,332.75	56,332.75
	02 - Steam Generation Plant	Manatee U2	31200	4.00%	508,552.43	508,552.43
	02 - Steam Generation Plant	Martin Comm	31200	4.10%	31,631.74	31,631.74
	02 - Steam Generation Plant	Martin U1	31100	1.50%	36,810.86	36,810.86
	02 - Steam Generation Plant	Martin U1	31200	1.80%	529,824.51	529,318.55
	02 - Steam Generation Plant	Martin U2	31100	1.50%	36,845.37	36,845.37
	02 - Steam Generation Plant	Martin U2	31200	1.50%	525,572.76	525,201.70
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.70%	127,911.34	127,911.34
	02 - Steam Generation Plant	PtEverglades Comm	31200	2.20%	67,787.69	67,787.69
	02 - Steam Generation Plant	PtEverglades U1	31200	6.70%	458,060.74	458,060.74
	02 - Steam Generation Plant	PtEverglades U2	31200	6.10%	480,321.84	480,321.84
	02 - Steam Generation Plant	PtEverglades U3	31200	4.00%	507,658.33	507,658.33
	02 - Steam Generation Plant	PtEverglades U4	31200	3.60%	517,303.41	517,303.41
	02 - Steam Generation Plant	Riviera Comm	31100	1.90%	60,973.18	60,973.18
	02 - Steam Generation Plant	Riviera Comm	31200	0.40%	11,495.25	11,495.25
	02 - Steam Generation Plant	Riviera U3	31200	1.70%	453,591.63	453,591.63
	02 - Steam Generation Plant	Riviera U4	31200	1.40%	437,621.87	437,621.87
	02 - Steam Generation Plant	Sanford U3	31100	4.00%	54,282.08	54,282.08
	02 - Steam Generation Plant	Sanford U3	31200	3.60%	425,269.85	426,269.85
	02 - Steam Generation Plant	Scherer U4	31200	1.90%	515,653.32	515,653.32
	02 - Steam Generation Plant	SJRPP - Comm	31100	3.10%	43,193.33	43,193.33
	02 - Steam Generation Plant	SJRPP U1	31200	2.20%	779.50	779.50
	02 - Steam Generation Plant	SJRPP U2	31200	2.30%	779.51	779.51
	02 - Steam Generation Plant	TurkeyPt Comm Fsil	31100	2.30%	59,056.19	59,056.19
	02 - Steam Generation Plant	TurkeyPt Comm Fsil	31200	2.10%	37,954.50	37,954.50
	02 - Steam Generation Plant	TurkeyPt U1	31200	2.00%	545,584.31	545,584.31
	02 - Steam Generation Plant	TurkeyPt U2	31200	1.80%	504,688.53	504,688.53
	05 - Other Generation Plant	FtLauderdale Comm	34100	4.10%	58,859.79	58,859.79
	05 - Other Generation Plant	FtLauderdale Comm	34500	4.10%	34,502.21	34,502.21
	05 - Other Generation Plant	FtLauderdale U4	34300	5.00%	462,254.20	462,254.20
	05 - Other Generation Plant	FtLauderdale U5	34300	3.70%	473,359.99	473,359.99
	05 - Other Generation Plant	FtMyers U2 CC	34300	5.50%	21,625.54	21,625.54
	05 - Other Generation Plant	FtMyers U3	34300	5.60%	0.00	5,000.00
	05 - Other Generation Plant	Martin U3	34300	5.80%	418,031.16	418,050.66
	05 - Other Generation Plant	Martin U4	34300	5.70%	410,632.93	410,652.42
	05 - Other Generation Plant	Martin U8	34300	5.50%	4,688.46	4,688.46
	05 - Other Generation Plant	Putnam Comm	34100	4.10%	82,857.82	82,857.82
	05 - Other Generation Plant	Putnam Comm	34300	6.30%	3,138.97	3,138.97
	05 - Other Generation Plant	Putnam U1	34300	5.20%	330,765.69	331,926.69
	05 - Other Generation Plant	Putnam U2	34300	5.40%	364,509.68	365,670.68
	05 - Other Generation Plant	Sanford U4	34300	5.60%	80,349.32	83,849.32
	05 - Other Generation Plant	Sanford U5	34300	5.70%	38,489.84	41,989.84
03 - Continuous Emission Monitoring Total					**11,867,698.60**	**11,882,182.57**

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Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Actual Balance December 2008	Estimated Balance December 2009
04 - Clean Closure Equivalency Demonstration						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.70%	17,254.20	17,254.20
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.70%	19,812.30	19,812.30
	02 - Steam Generation Plant	TurkeyPt Comm Fsil	31100	2.30%	21,799.28	21,799.28
04 - Clean Closure Equivalency Demonstration Total					**58,865.78**	**58,865.78**
05 - Maintenance of Above Ground Fuel Tanks						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.70%	901,636.88	901,636.88
	02 - Steam Generation Plant	Manatee Comm	31100	4.90%	3,111,263.35	3,111,263.35
	02 - Steam Generation Plant	Manatee Comm	31200	14.10%	174,543.23	219,543.23
	02 - Steam Generation Plant	Manatee U1	31200	4.80%	104,845.35	104,845.35
	02 - Steam Generation Plant	Manatee U2	31200	4.00%	127,429.19	127,429.19
	02 - Steam Generation Plant	Martin Comm	31100	1.70%	1,110,450.32	1,110,450.32
	02 - Steam Generation Plant	Martin Comm	31200	4.10%	0.00	94,671.98
	02 - Steam Generation Plant	Martin U1	31100	1.50%	176,338.83	176,338.83
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.70%	1,132,078.22	1,132,084.22
	02 - Steam Generation Plant	Riviera Comm	31100	1.90%	1,081,354.77	1,081,354.77
	02 - Steam Generation Plant	Sanford U3	31100	4.00%	796,754.11	796,754.11
	02 - Steam Generation Plant	SJRPP - Comm	31100	3.10%	42,091.24	42,091.24
	02 - Steam Generation Plant	SJRPP - Comm	31200	2.00%	2,292.39	2,292.39
	02 - Steam Generation Plant	TurkeyPt Comm Fsil	31100	2.30%	87,560.23	87,560.23
	02 - Steam Generation Plant	TurkeyPt U2	31100	2.10%	42,158.96	42,158.96
	05 - Other Generation Plant	FtLauderdale Comm	34200	4.40%	898,110.65	898,110.65
	05 - Other Generation Plant	FtLauderdale GTs	34200	4.50%	584,290.23	584,290.23
	05 - Other Generation Plant	FtMyers GTs	34200	5.00%	68,893.65	68,893.65
	05 - Other Generation Plant	PtEverglades GTs	34200	5.10%	2,359,099.94	2,359,099.94
	05 - Other Generation Plant	Putnam Comm	34200	3.70%	749,025.94	749,025.94
05 - Maintenance of Above Ground Fuel Tanks Total					**13,550,217.48**	**13,689,895.46**
07 - Relocate Turbine Lube Oil Piping						
	03 - Nuclear Generation Plant	StLucie U1	32300	1.20%	31,030.00	31,030.00
07 - Relocate Turbine Lube Oil Piping Total					**31,030.00**	**31,030.00**
08 - Oil Spill Clean-up/Response Equipment						
	02 - Steam Generation Plant	Amortizable	31650	5-Year	0.00	73,157.49
	02 - Steam Generation Plant	Amortizable	31670	7-Year	390,260.32	377,484.82
	02 - Steam Generation Plant	Martin Comm	31600	3.20%	23,107.32	23,107.32
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.70%	0.00	56,000.00
	05 - Other Generation Plant	Amortizable	34650	5-Year	9,274.60	23,274.60
	05 - Other Generation Plant	Amortizable	34670	7-Year	45,699.54	45,699.54
	08 - General Plant	Amortizable	39190	3-Year	1,943.47	1,943.47
08 - Oil Spill Clean-up/Response Equipment Total					**470,285.25**	**600,667.24**
10 - Reroute Storm Water Runoff						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.40%	117,793.83	117,793.83
10 - Reroute Storm Water Runoff Total					**117,793.83**	**117,793.83**
12 - Scherer Discharge Pipline						
	02 - Steam Generation Plant	Scherer Comm	31000	0.00%	9,936.72	9,936.72
	02 - Steam Generation Plant	Scherer Comm	31100	1.60%	524,872.97	524,872.97
	02 - Steam Generation Plant	Scherer Comm	31200	1.60%	328,761.62	328,761.62
	02 - Steam Generation Plant	Scherer Comm	31400	1.00%	689.11	689.11
12 - Scherer Discharge Pipline Total					**864,260.42**	**864,260.42**
20 - Wastewater/Stormwater Discharge Elimination						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.70%	706,500.94	706,500.94
	02 - Steam Generation Plant	Martin U1	31200	1.80%	380,994.77	380,994.77
	02 - Steam Generation Plant	Martin U2	31200	1.50%	416,671.92	416,671.92
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.70%	296,707.34	296,707.34
	02 - Steam Generation Plant	Riviera Comm	31100	1.90%	560,786.81	560,786.81
20 - Wastewater/Stormwater Discharge Elimination Total					**2,361,661.78**	**2,361,661.78**
21 - St. Lucie Turtle Nets						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.40%	249,319.93	286,248.99
21 - St. Lucie Turtle Nets Total					**249,319.93**	**286,248.99**

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Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Actual Balance December 2008	Estimated Balance December 2009
23 - Spill Prevention Clean-Up & Countermeasures						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.70%	689,323.23	689,323.23
	02 - Steam Generation Plant	CapeCanaveral Comm	31400	0.70%	13,451.85	13,451.85
	02 - Steam Generation Plant	CapeCanaveral Comm	31500	1.90%	33,805.48	33,805.48
	02 - Steam Generation Plant	Cutler Comm	31400	0.00%	12,236.00	12,236.00
	02 - Steam Generation Plant	Cutler U5	31400	0.20%	18,388.00	18,388.00
	02 - Steam Generation Plant	Manatee Comm	31100	4.90%	741,087.68	749,860.96
	02 - Steam Generation Plant	Manatee Comm	31500	3.70%	25,640.57	26,325.43
	02 - Steam Generation Plant	Martin Comm	31100	1.70%	378,539.84	343,785.10
	02 - Steam Generation Plant	Martin Comm	31500	1.30%	0.00	34,754.74
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.70%	2,952,949.32	2,967,759.91
	02 - Steam Generation Plant	PtEverglades Comm	31500	2.30%	7,782.85	7,782.85
	02 - Steam Generation Plant	Riviera Comm	31100	1.90%	205,014.03	205,014.03
	02 - Steam Generation Plant	Riviera U3	31200	1.70%	736,958.97	736,958.97
	02 - Steam Generation Plant	Riviera U4	31200	1.40%	894,298.77	894,298.77
	02 - Steam Generation Plant	Sanford U3	31100	4.00%	850,530.75	850,530.75
	02 - Steam Generation Plant	Sanford U3	31200	3.60%	211,727.22	211,727.22
	02 - Steam Generation Plant	TurkeyPt Comm Fsil	31100	2.30%	85,779.76	92,013.09
	02 - Steam Generation Plant	TurkeyPt Comm Fsil	31500	2.10%	13,559.00	13,559.00
	03 - Nuclear Generation Plant	StLucie U1	32300	1.20%	404,835.79	404,835.79
	03 - Nuclear Generation Plant	StLucie U1	32400	1.70%	437,945.38	437,945.38
	03 - Nuclear Generation Plant	StLucie U2	32300	1.90%	544,808.31	547,962.04
	05 - Other Generation Plant	Amortizable	34670	7-Year	7,065.10	7,065.10
	05 - Other Generation Plant	FtLauderdale Comm	34100	4.10%	189,219.17	189,219.17
	05 - Other Generation Plant	FtLauderdale Comm	34200	4.40%	1,480,169.46	1,480,169.46
	05 - Other Generation Plant	FtLauderdale Comm	34300	1.80%	28,250.00	28,250.00
	05 - Other Generation Plant	FtLauderdale GTs	34100	2.20%	92,726.74	92,726.74
	05 - Other Generation Plant	FtLauderdale GTs	34200	4.50%	513,250.07	513,250.07
	05 - Other Generation Plant	FtMyers GTs	34100	2.10%	98,714.92	98,714.92
	05 - Other Generation Plant	FtMyers GTs	34200	5.00%	629,983.29	629,983.29
	05 - Other Generation Plant	FtMyers GTs	34500	2.90%	12,430.00	12,430.00
	05 - Other Generation Plant	FtMyers U2 CC	34300	5.50%	49,727.00	49,727.00
	05 - Other Generation Plant	FtMyers U3 CC	34500	4.80%	12,430.00	12,430.00
	05 - Other Generation Plant	Martin Comm	34100	3.40%	61,215.95	61,215.95
	05 - Other Generation Plant	Martin U8	34200	4.80%	84,868.00	84,868.00
	05 - Other Generation Plant	PtEverglades GTs	34100	1.50%	454,080.68	454,080.68
	05 - Other Generation Plant	PtEverglades GTs	34200	5.10%	1,703,610.61	1,703,610.61
	05 - Other Generation Plant	PtEverglades GTs	34500	0.60%	0.00	7,782.85
	05 - Other Generation Plant	Putnam Comm	34100	4.10%	148,511.20	148,511.20
	05 - Other Generation Plant	Putnam Comm	34200	3.70%	1,713,191.94	1,713,191.94
	05 - Other Generation Plant	Putnam Comm	34500	4.20%	60,746.93	60,746.93
	06 - Transmission Plant - Electric		35200	2.50%	951,562.91	951,562.91
	06 - Transmission Plant - Electric		35300	2.80%	177,981.88	177,981.88
	07 - Distribution Plant - Electric		36100	2.60%	2,862,093.44	2,862,093.44
	08 - General Plant		39000	2.70%	12,843.35	12,843.35
23 - Spill Prevention Clean-Up & Countermeasures Total					**20,603,335.44**	**20,644,774.08**
24 - Manatee Reburn						
	02 - Steam Generation Plant	Manatee U1	31200	4.80%	16,771,308.37	16,771,308.37
	02 - Steam Generation Plant	Manatee U2	31200	4.00%	16,091,259.94	16,027,438.94
24 - Manatee Reburn Total					**32,862,568.31**	**32,798,747.31**

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Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Actual Balance December 2008	Estimated Balance December 2009
25 - PPE ESP Technology						
	02 - Steam Generation Plant	PtEverglades Comm	31200	2.20%	0.00	36,000.00
	02 - Steam Generation Plant	PtEverglades U1	31100	2.60%	298,709.93	298,709.93
	02 - Steam Generation Plant	PtEverglades U1	31200	6.70%	10,404,603.15	10,492,103.15
	02 - Steam Generation Plant	PtEverglades U1	31500	2.00%	2,500,248.85	2,500,248.85
	02 - Steam Generation Plant	PtEverglades U1	31600	1.00%	307,032.30	307,032.30
	02 - Steam Generation Plant	PtEverglades U2	31100	2.60%	184,084.01	184,084.01
	02 - Steam Generation Plant	PtEverglades U2	31200	6.10%	11,979,735.29	12,151,519.29
	02 - Steam Generation Plant	PtEverglades U2	31500	2.10%	3,954,581.63	3,954,581.63
	02 - Steam Generation Plant	PtEverglades U2	31600	1.70%	324,086.94	324,086.94
	02 - Steam Generation Plant	PtEverglades U3	31100	2.60%	713,693.44	713,693.44
	02 - Steam Generation Plant	PtEverglades U3	31200	4.00%	17,911,019.51	18,080,787.51
	02 - Steam Generation Plant	PtEverglades U3	31500	2.20%	4,304,056.69	4,304,056.69
	02 - Steam Generation Plant	PtEverglades U3	31600	1.00%	528,541.18	528,541.18
	02 - Steam Generation Plant	PtEverglades U4	31100	2.60%	313,275.79	313,275.79
	02 - Steam Generation Plant	PtEverglades U4	31200	3.60%	20,387,242.26	20,474,742.26
	02 - Steam Generation Plant	PtEverglades U4	31500	2.10%	6,729,950.05	6,729,950.05
	02 - Steam Generation Plant	PtEverglades U4	31600	1.30%	551,535.30	551,535.30
25 - PPE ESP Technology Total					**81,392,396.32**	**81,944,948.32**
26 - UST Remove/Replace						
	08 - General Plant		39000	2.70%	492,916.42	492,916.42
26 - UST Remove/Replace Total					**492,916.42**	**492,916.42**
31 - Clean Air Interstate Rule (CAIR)						
	02 - Steam Generation Plant	Manatee U1	31400	3.70%	277,326.13	277,326.13
	02 - Steam Generation Plant	Manatee U2	31200	4.00%	0.00	13,966,222.30
	02 - Steam Generation Plant	Manatee U2	31400	3.00%	0.00	7,051,266.58
	02 - Steam Generation Plant	Martin U1	31200	1.80%	10,580,457.33	10,327,159.88
	02 - Steam Generation Plant	Martin U1	31400	1.30%	6,985,668.11	7,694,692.34
	02 - Steam Generation Plant	Martin U2	31200	1.50%	0.00	13,726,187.02
	02 - Steam Generation Plant	Martin U2	31400	0.80%	0.00	5,843,761.48
	02 - Steam Generation Plant	SJRPP U1	31200	2.20%	210,549.74	27,350,345.33
	02 - Steam Generation Plant	SJRPP U2	31200	2.30%	222,893.37	27,221,617.39
	05 - Other Generation Plant	FtLauderdale GTs	34300	2.20%	110,241.57	110,241.57
	05 - Other Generation Plant	FtMyers GTs	34300	3.10%	57,855.19	57,855.19
	05 - Other Generation Plant	PtEverglades GTs	34300	2.60%	107,874.44	107,874.44
31 - Clean Air Interstate Rule (CAIR) Total					**18,552,865.88**	**113,734,549.65**
35 - Martin Drinking Water System						
	02 - Steam Generation Plant	Martin Comm	31100	1.70%	0.00	235,417.59
35 - Martin Drinking Water System Total					**0.00**	**235,417.59**
36 - Low Level Waste Storage						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.40%	0.00	3,807,997.00
	03 - Nuclear Generation Plant	TurkeyPt Comm	32100	1.10%	0.00	1,480,007.00
36 - Low Level Waste Storage Total					**0.00**	**5,288,004.00**
37 - DeSoto Solar Energy Center						
	05 - Other Generation Plant	DeSoto Solar Energy Center	34300	3.30%	0.00	150,719,261.61
	06 - Transmission Plant - Electric		35200	2.50%	0.00	2,715.43
	06 - Transmission Plant - Electric		35300	2.80%	0.00	367,956.45
	06 - Transmission Plant - Electric		35500	3.60%	0.00	407,620.78
	06 - Transmission Plant - Electric		35600	3.20%	0.00	177,168.47
	06 - Transmission Plant - Electric		36200	2.80%	0.00	46,014.03
37 - DeSoto Solar Energy Center Total					**0.00**	**151,720,736.77**
39 - Martin Solar Energy Center						
	05 - Other Generation Plant	Martin U8	34300	5.50%	0.00	350,000.00
	06 - Transmission Plant - Electric		35600	3.20%	0.00	956,266.12
39 - Martin Solar Energy Center Total					**0.00**	**1,306,266.12**
41 - Manatee Heaters						
	02 - Steam Generation Plant	Riviera Comm	31400	0.60%	0.00	4,688,928.00
41 - Manatee Heaters Total					**0.00**	**4,688,928.00**
Grand Total					**200,796,398.27**	**460,069,071.16**

APPENDIX I

ENVIRONMENTAL COST RECOVERY

COMMISSION FORMS 42-1P THROUGH 42-7P
JANUARY 2010 – DECEMBER 2010

TJK-3
DOCKET NO. 090007-EI
FPL WITNESS: T.J. KEITH
EXHIBIT ______
PAGES 1-125

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 5
COMPANY Florida Power & Light Company (Direct)
WITNESS T. J. Keith (TJK-3)
DATE 11/02/09

Form 42-1P

Florida Power & Light Company

Environmental Cost Recovery Clause

Total Jurisdictional Amount to Be Recovered

For the Projected Period

January 2010 to December 2010

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)	19,091,597	9,039,449	2,215,884	30,346,930
	b Projected Capital Projects (FORM 42-3P, Page 2 of 2, Lines 7 through 9)	26,410,290	117,977,296	0	144,387,586
	c Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b)	45,501,887	127,016,745	2,215,884	174,734,516
2	True-up for Estimated Over/(Under) Recovery for the current period January 2009 - December 2009 (FORM 42-1E, Line 4, filed on August 3, 2009)	1,192,511	2,294,954	115,288	3,602,753
3	Final True-up Over/(Under) for the period January 2008 - December 2008 (FORM 42-1A, Line 7, filed on April 1, 2009 and revised on Form 42-2E, Line 7a in the 2009 Estimated/Actual True-Up filed on August 3, 2009)	1,499,873	1,147,739	46,610	2,694,222
4	Total Jurisdictional Amount to be Recovered/(Refunded) in the projection period January 2010 - December 2010 (Line 1 - Line 2 - Line 3)	42,809,502	123,574,053	2,053,986	168,437,541
5	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier 1.00072)	42,840,325	123,663,026	2,055,465	168,558,816

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 Projection Amount for the Period
January 2010 - December 2010

O&M Activities
(in Dollars)

Line #	Project #	Estimated JAN	Estimated FEB	Estimated MAR	Estimated APR	Estimated MAY	Estimated JUN	6-Month Sub-Total
1	Description of O&M Activities							
	1 Air Operating Permit Fees-O&M	$ 108,405	$ 108,405	$ 108,405	$ 102,356	$ 102,356	$ 102,356	$632,283
	3a Continuous Emission Monitoring Systems-O&M	159,605	150,064	81,281	162,106	37,106	101,146	691,308
	5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	0	0	683,500	1,175,505	123,041	60,000	2,042,046
	8a Oil Spill Cleanup/Response Equipment-O&M	13,950	13,950	13,950	24,150	23,950	13,950	103,900
	13 RCRA Corrective Action-O&M	8,333	8,333	8,333	8,333	8,333	8,333	49,998
	14 NPDES Permit Fees-O&M	138,900	0	0	0	0	0	138,900
	17a Disposal of Noncontainerized Liquid Waste-O&M	0	30,000	55,000	25,000	70,000	30,000	210,000
	19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	208,000	208,000	208,000	208,000	208,000	208,000	1,248,000
	19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	62,917	62,917	62,917	62,917	62,917	62,917	377,502
	19c Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(280,116)
	20 Wastewater Discharge Elimination &Reuse	0	0	0	0	0	0	0
	NA Amortization of Gains on Sales of Emissions Allowances	(14,461)	(14,461)	(14,461)	(46,018)	(21,172)	(21,172)	(133,745)
	21 St. Lucie Turtle Net	0	0	0	0	0	0	0
	22 Pipeline Integrity Management	0	0	5,000	0	0	100,000	105,000
	23 SPCC - Spill Prevention, Control & Countermeasures	68,000	153,120	199,287	185,112	348,000	347,750	1,299,269
	24 Manatee Reburn	41,666	41,666	41,666	41,666	41,666	41,666	249,996
	25 Pt. Everglades ESP Technology	195,400	195,400	195,400	195,400	195,400	195,400	1,172,400
	26 UST Replacement/Removal	0	0	0	0	0	0	0
	27 Lowest Quality Water Source	25,203	25,203	25,203	25,203	25,203	25,203	151,218
	28 CWA 316(b) Phase II Rule	34,167	21,667	21,667	34,167	21,667	21,667	155,002
	29 SCR Consumables	29,166	29,166	29,166	29,166	29,166	29,166	174,996
	30 HBMP	2,833	2,833	2,833	2,833	2,833	2,833	16,998
	31 CAIR Compliance	90,000	106,000	481,000	113,000	90,000	90,000	970,000
	32 BART	0	0	0	0	0	0	0
	33 CAMR Compliance	0	0	0	0	413,000	413,000	826,000
	34 St. Lucie Cooling Water System Inspection & Maintenance	5,200	5,200	52,495	798,774	284,122	18,200	1,163,991
	35 Martin Plant Drinking Water System Compliance	0	0	0	0	0	0	0
	36 Low-Level Radioactive Waste Storage	0	0	0	0	0	0	0
	37 DeSoto Next Generation Solar Energy Center	100,840	200,840	132,840	75,840	75,840	86,840	673,040
	38 Space Coast Next Generation Solar Energy Center	8,140	22,500	29,360	20,160	39,520	48,420	168,100
	39 Martin Next Generation Solar Energy Center	0	0	0	0	0	0	0
	40 Greenhouse Gas Reduction Program	0	0	0	0	50,000	0	50,000
	41 Manatee Temporary Heating System Project	0	9,000	3,500	0	9,000	14,750	36,250
	42 Turkey Point Cooling Canal Monitoring Plan	50,000	50,000	100,000	100,000	200,000	200,000	700,000
	43 NESHAP Information Collection Request Project	973	755,973	904,280	904,280	760,273	1,947	3,327,726
2	Total of O&M Activities	$1,288,551	$2,139,090	$ 3,383,936	$ 4,199,264	$ 3,153,535	$2,155,686	$16,320,062
3	Recoverable Costs Allocated to Energy	$ 677,748	$1,478,207	$ 2,002,231	$ 1,652,150	$ 2,003,789	$1,215,253	$ 9,029,379
4a	Recoverable Costs Allocated to CP Demand	$ 426,146	$ 476,228	$ 1,197,048	$ 2,362,457	$ 965,089	$ 755,776	$ 6,182,741
4b	Recoverable Costs Allocated to GCP Demand	$ 184,657	$ 184,657	$ 184,657	$ 184,657	$ 184,657	$ 184,657	$ 1,107,942
5	Retail Energy Jurisdictional Factor	99.08384%	99.08384%	99.08384%	99.08384%	99.08384%	99.08384%	
6a	Retail CP Demand Jurisdictional Factor	99.09394%	99.09394%	99.09394%	99.09394%	99.09394%	99.09394%	
6b	Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	
7	Jurisdictional Energy Recoverable Costs (A)	$ 671,539	$1,464,664	$ 1,983,887	$ 1,637,014	$ 1,985,431	$1,204,119	$ 8,946,654
8a	Jurisdictional CP Demand Recoverable Costs (B)	$ 422,285	$ 471,911	$ 1,186,202	$ 2,341,051	$ 956,345	$ 748,928	$ 6,126,722
8b	Jurisdictional GCP Demand Recoverable Costs (C)	$ 184,657	$ 184,657	$ 184,657	$ 184,657	$ 184,657	$ 184,657	$ 1,107,942
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,278,481	$2,121,232	$ 3,354,746	$ 4,162,722	$ 3,126,433	$2,137,704	$16,181,318

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.

3

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Projection Amount for the Period
January 2010 - December 2010

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	$ 102,356	$ 102,356	$ 102,356	$ 102,356	$ 102,356	$ 102,356	$614,136	$1,246,419			$1,246,419
	3a Continuous Emission Monitoring Systems-O&M	159,405	95,143	37,106	37,331	88,164	37,114	454,263	1,145,571			1,145,571
	5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	0	0	0	0	9,000	0	9,000	2,051,046	2,051,046		
	8a Oil Spill Cleanup/Response Equipment-O&M	13,950	23,950	13,950	13,950	13,950	13,950	93,700	197,600			197,600
	13 RCRA Corrective Action-O&M	8,333	8,333	8,333	8,333	8,333	8,337	50,002	100,000	100,000		
	14 NPDES Permit Fees-O&M	0	0	0	0	0	0	0	138,900	138,900		
	17a Disposal of Noncontainerized Liquid Waste-O&M	30,000	0	0	0	0	0	30,000	240,000			240,000
	19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	208,000	208,000	208,000	208,000	208,000	208,000	1,248,000	2,496,000		2,496,000	
	19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	62,917	62,917	62,917	62,917	62,917	62,913	377,498	755,000	696,923		58,077
	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	(21,172)	(21,172)	(21,172)	(21,172)	(21,172)	(21,172)	(127,032)	(260,779)			(260,779)
	21 St. Lucie Turtle Net	0	0	0	0	0	0	0	0	0		
	22 Pipeline Integrity Management	300,000	0	0	0	0	0	300,000	405,000	405,000		
	23 SPCC - Spill Prevention, Control & Countermeasures	325,225	311,000	84,211	69,876	66,000	71,000	927,312	2,226,581	2,226,581		
	24 Manatee Reburn	41,666	41,666	41,666	41,666	41,668	41,674	250,004	500,000			500,000
	25 Pt. Everglades ESP Technology	195,400	195,400	195,400	195,400	195,400	195,407	1,172,407	2,344,807			2,344,807
	26 UST Replacement/Removal	0	0	0	0	0	0	0	0	0		
	27 Lowest Quality Water Source	25,203	25,203	25,203	25,203	25,203	25,203	151,218	302,436	302,436		
	28 CWA 316(b) Phase II Rule	21,667	21,667	21,667	21,667	21,667	21,663	129,998	285,000	285,000		
	29 SCR Consumables	29,166	29,166	29,166	29,166	29,170	29,170	175,004	350,000			350,000
	30 HBMP	2,833	2,833	2,833	2,833	2,833	2,837	17,002	34,000	34,000		
	31 CAIR Compliance	470,000	101,000	106,000	306,000	490,000	691,000	2,164,000	3,134,000			3,134,000
	32 BART	0	0	0	0	0	0	0	0			0
	33 CAMR Compliance	413,000	413,000	413,000	413,000	413,000	413,000	2,478,000	3,304,000			3,304,000
	34 St. Lucie Cooling Water System Inspection & Maintenance	5,200	5,120	167,070	3,801	3,401	3,400	187,992	1,351,983	1,351,983		
	35 Martin Plant Drinking Water System Compliance	0	0	0	17,000	0	0	17,000	17,000	17,000		
	36 Low-Level Radioactive Waste Storage	0	0	0	0	0	0	0	0	0		0
	37 DeSoto Next Generation Solar Energy Center	94,840	85,840	84,840	164,840	79,840	76,840	587,040	1,260,080	1,260,080		
	38 Space Coast Next Generation Solar Energy Center	55,720	50,620	52,720	94,120	45,720	44,720	343,620	511,720	511,720		
	39 Martin Next Generation Solar Energy Center	0	0	0	0	0	0	0	0	0		
	40 Greenhouse Gas Reduction Program	0	0	0	0	0	0	0	50,000			50,000
	41 Manatee Temporary Heating System Project	11,250	20,250	42,125	37,132	55,371	49,871	215,999	252,249			252,249
	42 Turkey Point Cooling Canal Monitoring Plan	550,000	550,000	550,000	350,000	350,000	350,000	2,700,000	3,400,000			3,400,000
	43 NESHAP Information Collection Request Project	0	0	0	0	0	0	0	3,327,726			3,327,726
2	Total of O&M Activities	$ 3,056,273	$ 2,285,606	$ 2,180,705	$ 2,136,733	$ 2,244,133	$ 2,380,597	$ 14,286,047	$ 30,606,107	$ 9,122,100	$ 2,215,884	$ 19,268,123
3	Recoverable Costs Allocated to Energy	$ 1,998,065	$ 1,553,803	$ 1,512,841	$ 1,507,873	$ 1,760,949	$ 1,905,414	$ 10,238,746	$ 19,268,123			
4a	Recoverable Costs Allocated to CP Demand	$ 875,551	$ 547,146	$ 483,407	$ 444,203	$ 298,527	$ 290,526	$ 2,939,359	$ 9,122,100			
4b	Recoverable Costs Allocated to GCP Demand	$ 184,657	$ 184,657	$ 184,657	$ 184,657	$ 184,657	$ 184,657	$ 1,107,942	$ 2,215,884			
5	Retail Energy Jurisdictional Factor	99.08384%	99.08384%	99.08384%	99.08384%	99.08384%	99.08384%					
6a	Retail CP Demand Jurisdictional Factor	99.09394%	99.09394%	99.09394%	99.09394%	99.09394%	99.09394%					
6b	Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%					
7	Jurisdictional Energy Recoverable Costs (A)	$ 1,979,760	$ 1,539,568	$ 1,498,783	$ 1,494,059	$ 1,744,816	$ 1,887,957	$ 10,144,943	$ 19,091,597			
8a	Jurisdictional CP Demand Recoverable Costs (B)	$ 867,618	$ 542,188	$ 479,027	$ 440,178	$ 295,822	$ 287,894	$ 2,912,727	$ 9,039,449			
8b	Jurisdictional GCP Demand Recoverable Costs (C)	$ 184,657	$ 184,657	$ 184,657	$ 184,657	$ 184,657	$ 184,657	$ 1,107,942	$ 2,215,884			
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 3,032,035	$ 2,266,413	$ 2,162,467	$ 2,118,894	$ 2,225,295	$ 2,360,508	$ 14,165,612	$ 30,346,930			

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.

Form 42-3P
Page 1 of 2

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Projection Amount for the Period
January 2010 - December 2010

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line # Project #		Estimated JAN	Estimated FEB	Estimated MAR	Estimated APR	Estimated MAY	Estimated JUN	6-Month Sub-Total
1	Description of Investment Projects (A)							
2	Low NOx Burner Technology-Capital	$63,258	$62,846	$62,434	$62,022	$61,610	$ 61,198	$ 373,369
3b	Continuous Emission Monitoring Systems-Capital	77,483	77,177	76,872	76,566	76,260	75,955	460,312
4b	Clean Closure Equivalency-Capital	301	300	299	298	297	296	1,791
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	136,248	135,832	135,417	135,002	134,587	134,171	811,257
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	125	124	124	124	123	123	743
8b	Oil Spill Cleanup/Response Equipment-Capital	10,498	10,409	10,320	10,242	10,164	10,747	62,380
10	Relocate Storm Water Runoff-Capital	773	772	771	769	768	767	4,620
NA	SO2 Allowances-Negative Return on Investment	(20,120)	(19,986)	(19,853)	(19,564)	(19,891)	(20,343)	(119,757)
12	Scherer Discharge Pipeline-Capital	5,038	5,028	5,017	5,007	4,996	4,986	30,071
17b	Disposal of Noncontainerized Liquid Waste-Capital	0	0	0	0	0	0	0
20	Wastewater Discharge Elimination & Reuse	19,457	19,422	19,389	19,355	19,321	19,287	116,232
21	St. Lucie Turtle Net	9,550	9,547	9,544	9,541	9,538	9,535	57,255
22	Pipeline Integrity Management	0	0	0	0	0	0	0
23	SPCC - Spill Prevention, Control & Countermeasures	220,709	221,598	221,240	221,195	221,120	220,959	1,326,820
24	Manatee Reburn	376,704	375,589	374,475	373,360	372,246	371,131	2,243,506
25	Pt. Everglades ESP Technology	919,447	916,877	914,899	912,919	910,345	907,771	5,482,259
26	UST Removal / Replacement	5,391	5,380	5,370	5,360	5,350	5,339	32,190
31	CAIR Compliance	2,764,912	2,845,460	2,950,897	3,090,371	3,245,399	3,361,019	18,258,058
33	CAMR Compliance	850,594	853,045	864,684	959,668	1,052,365	1,066,010	5,646,366
34	St. Lucie Cooling Water System Inspection & Maintenance	0	0	0	0	0	0	0
35	Martin Plant Drinking Water System Compliance	2,474	2,471	2,468	2,465	2,462	2,459	14,800
36	Low-Level Radioactive Waste Storage	54,650	54,596	54,542	54,489	54,435	54,381	327,093
37	DeSoto Next Generation Solar Energy Center	1,812,609	1,808,752	1,804,894	1,801,036	1,797,178	1,793,321	10,817,790
38	Space Coast Next Generation Solar Energy Center	300,992	345,923	423,325	501,430	604,339	801,774	2,977,783
39	Martin Next Generation Solar Energy Center	2,179,438	2,511,411	2,764,014	2,971,188	3,137,205	3,288,427	16,851,683
41	Manatee Temporary Heating System Project	45,686	45,665	45,643	45,621	45,600	45,578	273,793
42	Turkey Point Cooling Canal Monitoring Plan	0	0	0	0	0	0	0
2	Total Investment Projects - Recoverable Costs	$ 9,836,217	$ 10,288,238	$ 10,726,785	$11,238,464	$11,745,817	$12,214,891	$66,050,414
3	Recoverable Costs Allocated to Energy	$ 2,064,422	$ 2,095,252	$ 2,125,593	$ 2,161,700	$ 2,196,358	$ 2,227,957	$12,871,283
4	Recoverable Costs Allocated to Demand	$ 7,771,795	$ 8,192,986	$ 8,601,192	$ 9,076,764	$ 9,549,459	$ 9,986,934	$53,179,131
5	Retail Energy Jurisdictional Factor	99.08384%	99.08384%	99.08384%	99.08384%	99.08384%	99.08384%	
6	Retail Demand Jurisdictional Factor	99.09394%	99.09394%	99.09394%	99.09394%	99.09394%	99.09394%	
7	Jurisdictional Energy Recoverable Costs (B)	$ 2,045,508	$ 2,076,056	$ 2,106,119	$ 2,141,895	$ 2,176,236	$ 2,207,545	$12,753,359
8	Jurisdictional Demand Recoverable Costs (C)	$ 7,701,378	$ 8,118,752	$ 8,523,260	$ 8,994,523	$ 9,462,935	$ 9,896,446	$52,697,294
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 9,746,886	$ 10,194,808	$ 10,629,379	$11,136,418	$11,639,171	$12,103,991	$65,450,653

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 Projection Amount for the Period
January 2010 - December 2010

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	$ 60,787	$ 60,375	$ 59,963	$ 59,551	$ 59,139	$ 58,727	$ 358,542	$ 731,911		$ 731,911
3b Continuous Emission Monitoring Systems-Capital	75,649	75,343	75,038	74,732	74,426	74,121	449,309	909,622		909,622
4b Clean Closure Equivalency-Capital	295	294	293	292	291	290	1,755	3,545	3,272	273
5b Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	133,756	133,341	132,926	132,511	132,095	131,680	796,309	1,607,566	1,483,907	123,659
7 Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	123	123	122	122	122	121	733	1,476	1,362	114
8b Oil Spill Cleanup/Response Equipment-Capital	11,300	11,202	11,750	12,302	12,205	12,801	71,560	133,940	123,637	10,303
10 Relocate Storm Water Runoff-Capital	766	764	763	762	760	759	4,574	9,194	8,487	707
NA SO2 Allowances-Negative Return on Investment	(19,287)	(19,091)	(18,895)	(18,699)	(18,503)	(18,308)	(112,783)	(232,540)		(232,540)
12 Scherer Discharge Pipeline-Capital	4,975	4,965	4,954	4,943	4,933	4,922	29,692	59,764	55,167	4,597
17b Disposal of Noncontainerized Liquid Waste-Capital	0	0	0	0	0	0	0	0	0	0
20 Wastewater Discharge Elimination &Reuse	19,254	19,220	19,186	19,152	19,119	19,085	115,016	231,248	213,460	17,788
21 St. Lucie Turtle Net	9,532	9,529	9,526	9,523	9,519	9,516	57,145	114,400	105,600	8,800
22 Pipeline Integrity Management	0	0	0	0	0	6,395	6,395	6,395	5,903	492
23 SPCC - Spill Prevention, Control & Countermeasures	220,912	220,836	224,064	227,086	226,567	226,048	1,345,513	2,672,333	2,466,769	205,564
24 Manatee Reburn	370,017	368,902	367,788	366,673	365,559	364,445	2,203,384	4,446,890		4,446,890
25 Pt. Everglades ESP Technology	905,197	902,623	900,049	897,964	895,879	893,302	5,395,014	10,877,274		10,877,274
26 UST Removal / Replacement	5,329	5,319	5,309	5,298	5,288	5,278	31,821	64,011	59,087	4,924
31 CAIR Compliance	3,455,692	3,534,654	3,612,810	3,699,377	3,798,735	3,995,739	22,097,007	40,355,064	37,250,828	3,104,236
33 CAMR Compliance	1,080,129	1,095,258	1,110,157	1,122,832	1,132,559	1,158,713	6,699,648	12,346,015	11,396,322	949,693
34 St. Lucie Cooling Water System Inspection & Maintenance	0	0	0	0	0	0	0	0	0	0
35 Martin Plant Drinking Water System Compliance	2,456	2,453	2,450	2,447	2,443	2,440	14,689	29,488	27,220	2,268
36 Low-Level Radioactive Waste Storage	54,328	54,274	54,220	78,381	102,516	102,412	446,131	773,224	713,745	59,479
37 DeSoto Next Generation Solar Energy Center	1,789,463	1,785,605	1,781,747	1,777,889	1,774,032	1,770,174	10,678,910	21,496,699	19,843,107	1,653,592
38 Space Coast Next Generation Solar Energy Center	939,548	942,740	940,733	938,726	936,719	934,712	5,633,178	8,610,961	7,948,579	662,382
39 Martin Next Generation Solar Energy Center	3,432,035	3,563,220	3,668,837	3,763,667	3,852,118	4,504,278	22,784,155	39,635,837	36,586,926	3,048,911
41 Manatee Temporary Heating System Project	45,556	45,535	68,414	91,379	91,430	91,383	433,697	707,489	653,067	54,422
42 Turkey Point Cooling Canal Monitoring Plan	0	13,209	26,406	26,384	26,362	26,340	118,701	118,701	109,570	9,131
2 Total Investment Projects - Recoverable Costs	$ 12,597,812	$ 12,830,693	$ 13,058,610	$ 13,293,294	$13,504,313	$14,375,373	$79,660,095	$ 145,710,507	$ 119,056,015	$26,654,492
3 Recoverable Costs Allocated to Energy	$ 2,254,321	$ 2,268,347	$ 2,281,994	$ 2,296,611	$ 2,309,409	$ 2,372,524	$13,783,207	$ 26,654,492		
4 Recoverable Costs Allocated to Demand	$ 10,343,491	$ 10,562,346	$ 10,776,616	$ 10,996,683	$11,194,904	$12,002,849	$65,876,888	$ 119,056,015		
5 Retail Energy Jurisdictional Factor	99.08384%	99.08384%	99.08384%	99.08384%	99.08384%	99.08384%				
6 Retail Demand Jurisdictional Factor	99.09394%	99.09394%	99.09394%	99.09394%	99.09394%	99.09394%				
7 Jurisdictional Energy Recoverable Costs (B)	$ 2,233,667	$ 2,247,566	$ 2,261,088	$ 2,275,571	$ 2,288,251	$ 2,350,788	$13,656,931	$ 26,410,290		
8 Jurisdictional Demand Recoverable Costs (C)	$ 10,249,773	$ 10,466,644	$ 10,678,973	$ 10,897,046	$11,093,471	$11,894,095	$65,280,002	$ 117,977,296		
9 Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 12,483,440	$ 12,714,210	$ 12,940,061	$ 13,172,617	$13,381,722	$14,244,883	$78,936,933	$ 144,387,586		

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 2010

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	$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)	$17,321,183	17,321,183	17,321,183	17,321,183	17,321,183	17,321,183	17,321,183	n/a
3.	Less: Accumulated Depreciation (C)	$15,274,799	15,319,338	15,363,876	15,408,415	15,452,954	15,497,493	15,542,032	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$2,046,384	$2,001,845	$1,957,306	$1,912,768	$1,868,229	$1,823,690	$1,779,151	n/a
6.	Average Net Investment		2,024,115	1,979,576	1,935,037	1,890,498	1,845,959	1,801,421	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		15,554	15,211	14,869	14,527	14,185	13,842	$88,188
	b. Debt Component (Line 6 x 1.8767% x 1/12)		3,166	3,096	3,026	2,957	2,887	2,817	$17,948
8.	Investment Expenses								
	a. Depreciation (E)		44,539	44,539	44,539	44,539	44,539	44,539	$267,233
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$63,258	$62,846	$62,434	$62,022	$61,610	$61,198	$373,369

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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		$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)	$17,321,183	17,321,183	17,321,183	17,321,183	17,321,183	17,321,183	17,321,183	n/a
3. Less: Accumulated Depreciation (C)	$15,542,032	15,586,571	15,631,109	15,675,648	15,720,187	15,764,726	15,809,265	n/a
4. CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5. Net Investment (Lines 2 - 3 + 4)	$1,779,151	$1,734,612	$1,690,073	$1,645,535	$1,600,996	$1,556,457	$1,511,918	n/a
6. Average Net Investment		1,756,882	1,712,343	1,667,804	1,623,265	1,578,726	1,534,187	n/a
7. Return on Average Net Investment								
a. Equity Component grossed up for taxes (D)		13,500	13,158	12,816	12,473	12,131	11,789	164,056
b. Debt Component (Line 6 x 1.8767% x 1/12)		2,748	2,678	2,608	2,539	2,469	2,399	33,389
8. Investment Expenses								
a. Depreciation (E)		44,539	44,539	44,539	44,539	44,539	44,539	534,466
b. Amortization (F)								
c. Dismantlement								
d. Property Expenses								
e. Other (G)								
9. Total System Recoverable Expenses (Lines 7 & 8)		$60,787	$60,375	$59,963	$59,551	$59,139	$58,727	$731,911

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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		$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)	$11,882,183	11,882,183	11,882,183	11,882,183	11,882,183	11,882,183	11,882,183	n/a
3.	Less: Accumulated Depreciation (C)	$7,060,907	7,093,955	7,127,003	7,160,051	7,193,099	7,226,147	7,259,195	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$4,821,276	$4,788,228	$4,755,180	$4,722,132	$4,689,083	$4,656,035	$4,622,987	n/a
6.	Average Net Investment		4,804,752	4,771,704	4,738,656	4,705,608	4,672,559	4,639,511	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		36,921	36,667	36,413	36,159	35,905	35,651	$217,714
	b. Debt Component (Line 6 x 1.8767% x 1/12)		7,514	7,462	7,411	7,359	7,307	7,256	$44,310
8.	Investment Expenses								
	a. Depreciation (E)		33,048	33,048	33,048	33,048	33,048	33,048	$198,289
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$77,483	$77,177	$76,872	$76,566	$76,260	$75,955	$460,312

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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		$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
d. Other (A)		-	-	-	-	-	-	
2. Plant-In-Service/Depreciation Base (B)	$11,882,183	11,882,183	11,882,183	11,882,183	11,882,183	11,882,183	11,882,183	n/a
3. Less: Accumulated Depreciation (C)	$7,259,195	7,292,243	7,325,292	7,358,340	7,391,388	7,424,436	7,457,484	n/a
4. CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5. Net Investment (Lines 2 - 3 + 4)	$4,622,987	$4,589,939	$4,556,891	$4,523,843	$4,490,795	$4,457,747	$4,424,698	n/a
6. Average Net Investment		4,606,463	4,573,415	4,540,367	4,507,319	4,474,271	4,441,222	n/a
7. Return on Average Net Investment								
a. Equity Component grossed up for taxes (D)		35,397	35,143	34,889	34,635	34,381	34,127	426,286
b. Debt Component (Line 6 x 1.8767% x 1/12)		7,204	7,152	7,101	7,049	6,997	6,946	86,759
8. Investment Expenses								
a. Depreciation (E)		33,048	33,048	33,048	33,048	33,048	33,048	396,578
b. Amortization (F)								
c. Dismantlement								
d. Property Expenses								
e. Other (G)								
9. Total System Recoverable Expenses (Lines 7 & 8)		$75,649	$75,343	$75,038	$74,732	$74,426	$74,121	$909,622

Notes:
(A) Reserve Transfer
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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		$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)	$58,866	58,866	58,866	58,866	58,866	58,866	58,866	n/a
3.	Less: Accumulated Depreciation (C)	$38,240	38,351	38,462	38,572	38,683	38,794	38,905	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$20,626	$20,515	$20,404	$20,293	$20,182	$20,072	$19,961	n/a
6.	Average Net Investment		20,570	20,460	20,349	20,238	20,127	20,016	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		158	157	156	156	155	154	$936
	b. Debt Component (Line 6 x 1.8767% x 1/12)		32	32	32	32	31	31	$190
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)		$301	$300	$299	$298	$297	$296	$1,791

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Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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		$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)	$58,866	58,866	58,866	58,866	58,866	58,866	58,866	n/a
3.	Less: Accumulated Depreciation (C)	$38,905	39,016	39,126	39,237	39,348	39,459	39,570	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$19,961	$19,850	$19,739	$19,628	$19,518	$19,407	$19,296	n/a
6.	Average Net Investment		19,905	19,795	19,684	19,573	19,462	19,351	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		153	152	151	150	150	149	1,841
	b. Debt Component (Line 6 x 1.8767% x 1/12)		31	31	31	31	30	30	375
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)		$295	$294	$293	$292	$291	$290	$3,545

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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		$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)	$13,689,895	13,689,895	13,689,895	13,689,895	13,689,895	13,689,895	13,689,895	n/a
3.	Less: Accumulated Depreciation (C)	$3,789,827	3,834,725	3,879,624	3,924,523	3,969,421	4,014,320	4,059,219	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$9,900,069	$9,855,170	$9,810,271	$9,765,373	$9,720,474	$9,675,575	$9,630,677	n/a
6.	Average Net Investment		9,877,619	9,832,721	9,787,822	9,742,923	9,698,025	9,653,126	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		75,901	75,556	75,211	74,866	74,521	74,176	$450,233
	b. Debt Component (Line 6 x 1.8767% x 1/12)		15,448	15,377	15,307	15,237	15,167	15,097	$91,632
8.	Investment Expenses								
	a. Depreciation (E)		44,899	44,899	44,899	44,899	44,899	44,899	$269,392
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$136,248	$135,832	$135,417	$135,002	$134,587	$134,171	$811,257

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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		$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)	$13,689,895	13,689,895	13,689,895	13,689,895	13,689,895	13,689,895	13,689,895	n/a
3.	Less: Accumulated Depreciation (C)	$4,059,219	4,104,117	4,149,016	4,193,915	4,238,813	4,283,712	4,328,611	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$9,630,677	$9,585,778	$9,540,879	$9,495,981	$9,451,082	$9,406,183	$9,361,285	n/a
6.	Average Net Investment		9,608,227	9,563,329	9,518,430	9,473,531	9,428,633	9,383,734	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		73,831	73,486	73,141	72,796	72,451	72,106	888,045
	b. Debt Component (Line 6 x 1.8767% x 1/12)		15,026	14,956	14,886	14,816	14,745	14,675	180,737
8.	Investment Expenses								
	a. Depreciation (E)		44,899	44,899	44,899	44,899	44,899	44,899	538,784
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$133,756	$133,341	$132,926	$132,511	$132,095	$131,680	$1,607,566

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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		$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)	$31,030	31,030	31,030	31,030	31,030	31,030	31,030	n/a
3.	Less: Accumulated Depreciation (C)	$20,899	20,930	20,961	20,992	21,023	21,054	21,085	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$10,131	$10,100	$10,069	$10,038	$10,007	$9,976	$9,945	n/a
6.	Average Net Investment		10,116	10,085	10,054	10,023	9,992	9,961	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		78	77	77	77	77	77	$463
	b. Debt Component (Line 6 x 1.8767% x 1/12)		16	16	16	16	16	16	$94
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)		$125	$124	$124	$124	$123	$123	$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 42-4P, pages 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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		$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)	$31,030	31,030	31,030	31,030	31,030	31,030	31,030	n/a
3.	Less: Accumulated Depreciation (C)	$21,085	21,116	21,147	21,178	21,209	21,240	21,271	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$9,945	$9,914	$9,883	$9,852	$9,821	$9,790	$9,759	n/a
6.	Average Net Investment		9,930	9,899	9,868	9,837	9,805	9,774	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		76	76	76	76	75	75	917
	b. Debt Component (Line 6 x 1.8767% x 1/12)		16	15	15	15	15	15	187
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)		$123	$123	$122	$122	$122	$121	$1,476

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	($4,363)	$0	($2,467)	$50,000	$43,170
	c. Retirements		$0	$0	($4,363)	$0	($2,467)	$0	($6,830)
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$600,667	600,667	600,667	596,304	596,304	593,837	643,837	n/a
3.	Less: Accumulated Depreciation (C)	$206,270	213,153	220,009	222,477	229,293	233,628	240,846	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$394,397	$387,515	$380,658	$373,827	$367,011	$360,209	$402,991	n/a
6.	Average Net Investment		390,956	384,086	377,242	370,419	363,610	381,600	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,004	2,951	2,899	2,846	2,794	2,932	$17,427
	b. Debt Component (Line 6 x 1.8767% x 1/12)		611	601	590	579	569	597	$3,547
8.	Investment Expenses								
	a. Depreciation (E)		6,883	6,857	6,831	6,816	6,801	7,218	$41,406
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$10,498	$10,409	$10,320	$10,242	$10,164	$10,747	$62,380

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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		$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	($1,943)	$50,000	($7,776)	$0	$108,636	$192,087
c. Retirements		$0	($1,943)	$0	($7,776)	$0	($3,364)	($19,913)
d. Other (A)								0
2. Plant-In-Service/Depreciation Base (B)	$643,837	643,837	641,894	691,894	684,118	684,118	792,754	n/a
3. Less: Accumulated Depreciation (C)	$240,846	248,454	254,091	262,061	262,650	270,995	276,133	n/a
4. CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5. Net Investment (Lines 2 - 3 + 4)	$402,991	$395,383	$387,803	$429,833	$421,468	$413,122	$516,620	n/a
6. Average Net Investment		399,187	391,593	408,818	425,651	417,295	464,871	n/a
7. Return on Average Net Investment								
a. Equity Component grossed up for taxes (D)		3,067	3,009	3,141	3,271	3,207	3,572	36,694
b. Debt Component (Line 6 x 1.8767% x 1/12)		624	612	639	666	653	727	7,468
8. Investment Expenses								
a. Depreciation (E)		7,608	7,581	7,969	8,365	8,346	8,502	89,777
b. Amortization (F)								
c. Dismantlement								
d. Property Expenses								
e. Other (G)								
9. Total System Recoverable Expenses (Lines 7 & 8)		$11,300	$11,202	$11,750	$12,302	$12,205	$12,801	$133,940

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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		$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)	$117,794	117,794	117,794	117,794	117,794	117,794	117,794	n/a
3.	Less: Accumulated Depreciation (C)	$48,985	49,123	49,260	49,398	49,535	49,672	49,810	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$68,809	$68,671	$68,534	$68,396	$68,259	$68,121	$67,984	n/a
6.	Average Net Investment		68,740	68,602	68,465	68,328	68,190	68,053	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		528	527	526	525	524	523	$3,153
	b. Debt Component (Line 6 x 1.8767% x 1/12)		108	107	107	107	107	106	$642
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)		$773	$772	$771	$769	$768	$767	$4,620

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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		$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)	$117,794	117,794	117,794	117,794	117,794	117,794	117,794	n/a
3.	Less: Accumulated Depreciation (C)	$49,810	49,947	50,085	50,222	50,360	50,497	50,634	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$67,984	$67,847	$67,709	$67,572	$67,434	$67,297	$67,159	n/a
6.	Average Net Investment		67,915	67,778	67,640	67,503	67,366	67,228	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		522	521	520	519	518	517	6,269
	b. Debt Component (Line 6 x 1.8767% x 1/12)		106	106	106	106	105	105	1,276
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)		$766	$764	$763	$762	$760	$759	$9,194

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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		$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)	$864,260	864,260	864,260	864,260	864,260	864,260	864,260	n/a
3.	Less: Accumulated Depreciation (C)	$442,037	443,175	444,314	445,453	446,592	447,730	448,869	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$422,224	$421,085	$419,946	$418,808	$417,669	$416,530	$415,391	n/a
6.	Average Net Investment		421,654	420,516	419,377	418,238	417,099	415,961	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,240	3,231	3,223	3,214	3,205	3,196	$19,309
	b. Debt Component (Line 6 x 1.8767% x 1/12)		659	658	656	654	652	651	$3,930
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)		$5,038	$5,028	$5,017	$5,007	$4,996	$4,986	$30,071

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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		$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)	$864,260	864,260	864,260	864,260	864,260	864,260	864,260	n/a
3.	Less: Accumulated Depreciation (C)	$448,869	450,008	451,147	452,285	453,424	454,563	455,702	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$415,391	$414,253	$413,114	$411,975	$410,836	$409,698	$408,559	n/a
6.	Average Net Investment		414,822	413,683	412,544	411,406	410,267	409,128	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,188	3,179	3,170	3,161	3,153	3,144	38,303
	b. Debt Component (Line 6 x 1.8767% x 1/12)		649	647	645	643	642	640	7,796
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)		$4,975	$4,965	$4,954	$4,943	$4,933	$4,922	$59,764

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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		$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 42-4P, pages 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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		$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 42-4P, pages 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Wastewater/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		$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)	$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)	$650,566	654,215	657,864	661,513	665,162	668,810	672,459	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,711,096	$1,707,446	$1,703,798	$1,700,149	$1,696,500	$1,692,851	$1,689,203	n/a
6.	Average Net Investment		1,709,271	1,705,622	1,701,973	1,698,325	1,694,676	1,691,027	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		13,134	13,106	13,078	13,050	13,022	12,994	$78,385
	b. Debt Component (Line 6 x 1.8767% x 1/12)		2,673	2,667	2,662	2,656	2,650	2,645	$15,953
8.	Investment Expenses								
	a. Depreciation (E)		3,650	3,649	3,649	3,649	3,649	3,649	$21,893
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$19,457	$19,422	$19,389	$19,355	$19,321	$19,287	$116,232

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Wastewater/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		$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)	$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)	$672,459	676,108	679,756	683,405	687,054	690,703	694,351	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,689,203	$1,685,554	$1,681,905	$1,678,257	$1,674,608	$1,670,959	$1,667,310	n/a
6.	Average Net Investment		1,687,378	1,683,730	1,680,081	1,676,432	1,672,783	1,669,135	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		12,966	12,938	12,910	12,882	12,854	12,826	155,761
	b. Debt Component (Line 6 x 1.8767% x 1/12)		2,639	2,633	2,627	2,622	2,616	2,610	31,701
8.	Investment Expenses								
	a. Depreciation (E)		3,649	3,649	3,649	3,649	3,649	3,649	43,786
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$19,254	$19,220	$19,186	$19,152	$19,119	$19,085	$231,248

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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		$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)	$286,249	286,249	286,249	286,249	286,249	286,249	286,249	n/a
3.	Less: Accumulated Depreciation (C)	($710,488)	(710,154)	(709,820)	(709,486)	(709,152)	(708,818)	(708,484)	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$996,737	$996,403	$996,069	$995,735	$995,401	$995,067	$994,733	n/a
6.	Average Net Investment		996,570	996,236	995,902	995,568	995,234	994,900	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		7,658	7,655	7,653	7,650	7,648	7,645	$45,908
	b. Debt Component (Line 6 x 1.8767% x 1/12)		1,559	1,558	1,557	1,557	1,556	1,556	$9,343
8.	Investment Expenses								
	a. Depreciation (E)		334	334	334	334	334	334	$2,004
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$9,550	$9,547	$9,544	$9,541	$9,538	$9,535	$57,255

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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		$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)	$286,249	286,249	286,249	286,249	286,249	286,249	286,249	n/a
3.	Less: Accumulated Depreciation (C)	($708,484)	(708,150)	(707,816)	(707,482)	(707,148)	(706,814)	(706,480)	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$994,733	$994,399	$994,065	$993,731	$993,397	$993,063	$992,729	n/a
6.	Average Net Investment		994,566	994,232	993,898	993,564	993,230	992,896	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		7,642	7,640	7,637	7,635	7,632	7,630	91,724
	b. Debt Component (Line 6 x 1.8767% x 1/12)		1,555	1,555	1,554	1,554	1,553	1,553	18,668
8.	Investment Expenses								
	a. Depreciation (E)		334	334	334	334	334	334	4,008
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$9,532	$9,529	$9,526	$9,523	$9,519	$9,516	$114,400

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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		$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 42-4P, pages 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$1,200,000	$1,200,000
	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	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	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$1,199,150	n/a
6.	Average Net Investment		0	0	0	0	0	599,575	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	4,607	4,607
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	938	938
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	850	850
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$6,395	$6,395

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$260,400	$0	$25,000	$55,000	$20,000	$40,000	$400,400
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$20,644,774	20,905,174	20,905,174	20,930,174	20,985,174	21,005,174	21,045,174	n/a
3.	Less: Accumulated Depreciation (C)	$2,712,613	2,766,529	2,820,630	2,874,757	2,928,970	2,983,264	3,037,622	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$17,932,161	$18,138,645	$18,084,544	$18,055,417	$18,056,204	$18,021,910	$18,007,552	n/a
6.	Average Net Investment		18,035,403	18,111,594	18,069,981	18,055,810	18,039,057	18,014,731	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		138,587	139,173	138,853	138,744	138,615	138,428	$832,400
	b. Debt Component (Line 6 x 1.8767% x 1/12)		28,206	28,325	28,260	28,237	28,211	28,173	$169,412
8.	Investment Expenses								
	a. Depreciation (E)		53,916	54,101	54,127	54,213	54,294	54,358	$325,009
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$220,709	$221,598	$221,240	$221,195	$221,120	$220,959	$1,326,820

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$40,000	$35,000	$600,000	$0	$0	$0	$1,075,400
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$21,045,174	21,085,174	21,120,174	21,720,174	21,720,174	21,720,174	21,720,174	n/a
3.	Less: Accumulated Depreciation (C)	$3,037,622	3,092,066	3,146,590	3,201,915	3,258,001	3,314,088	3,370,175	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$18,007,552	$17,993,108	$17,973,584	$18,518,260	$18,462,173	$18,406,086	$18,349,999	n/a
6.	Average Net Investment		18,000,330	17,983,346	18,245,922	18,490,216	18,434,129	18,378,042	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		138,318	138,187	140,205	142,082	141,651	141,220	1,674,062
	b. Debt Component (Line 6 x 1.8767% x 1/12)		28,151	28,124	28,535	28,917	28,829	28,741	340,709
8.	Investment Expenses								
	a. Depreciation (E)		54,444	54,524	55,324	56,087	56,087	56,087	657,562
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$220,912	$220,836	$224,064	$227,086	$226,567	$226,048	$2,672,333

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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	$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)	$32,798,747	32,798,747	32,798,747	32,798,747	32,798,747	32,798,747	32,798,747	n/a
3.	Less: Accumulated Depreciation (C)	$5,036,077	5,156,587	5,277,097	5,397,607	5,518,117	5,638,627	5,759,137	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$27,762,670	$27,642,160	$27,521,650	$27,401,140	$27,280,630	$27,160,120	$27,039,610	n/a
6.	Average Net Investment		27,702,415	27,581,905	27,461,395	27,340,885	27,220,375	27,099,865	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		212,870	211,944	211,018	210,092	209,166	208,240	$1,263,330
	b. Debt Component (Line 6 x 1.8767% x 1/12)		43,324	43,135	42,947	42,758	42,570	42,381	$257,116
8.	Investment Expenses								
	a. Depreciation (E)		120,510	120,510	120,510	120,510	120,510	120,510	$723,060
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$376,704	$375,589	$374,475	$373,360	$372,246	$371,131	$2,243,506

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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

33

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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)	$32,798,747	32,798,747	32,798,747	32,798,747	32,798,747	32,798,747	32,798,747	n/a
3.	Less: Accumulated Depreciation (C)	$5,759,137	5,879,647	6,000,157	6,120,667	6,241,177	6,361,687	6,482,197	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$27,039,610	$26,919,100	$26,798,590	$26,678,080	$26,557,570	$26,437,060	$26,316,550	n/a
6.	Average Net Investment		26,979,355	26,858,845	26,738,335	26,617,825	26,497,315	26,376,805	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		207,314	206,388	205,462	204,536	203,610	202,684	2,493,323
	b. Debt Component (Line 6 x 1.8767% x 1/12)		42,193	42,005	41,816	41,628	41,439	41,251	507,447
8.	Investment Expenses								
	a. Depreciation (E)		120,510	120,510	120,510	120,510	120,510	120,510	1,446,120
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$370,017	$368,902	$367,788	$366,673	$365,559	$364,445	$4,446,890

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$80,000	$0	$0	$0	$80,000
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$81,944,948	81,944,948	81,944,948	82,024,948	82,024,948	82,024,948	82,024,948	n/a
3.	Less: Accumulated Depreciation (C)	$12,434,064	12,711,954	12,989,845	13,267,959	13,546,296	13,824,633	14,102,970	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$69,510,885	$69,232,994	$68,955,104	$68,756,990	$68,478,653	$68,200,316	$67,921,979	n/a
6.	Average Net Investment		69,371,940	69,094,049	68,856,047	68,617,821	68,339,484	68,061,147	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		533,066	530,930	529,101	527,271	525,132	522,993	$3,168,493
	b. Debt Component (Line 6 x 1.8767% x 1/12)		108,491	108,056	107,684	107,311	106,876	106,441	$644,859
8.	Investment Expenses								
	a. Depreciation (E)		277,891	277,891	278,114	278,337	278,337	278,337	$1,668,906
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$919,446.91	$916,877	$914,899	$912,919	$910,345	$907,771	$5,482,259

Notes:

(A) N/A
(B) 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 55-59.
(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 5.6840% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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	$80,000	$0	$0	$160,000
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$82,024,948	82,024,948	82,024,948	82,024,948	82,104,948	82,104,948	82,104,948	n/a
3.	Less: Accumulated Depreciation (C)	$14,102,970	14,381,307	14,659,645	14,937,982	15,216,439	15,495,016	15,773,593	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$67,921,979	$67,643,641	$67,365,304	$67,086,967	$66,888,510	$66,609,933	$66,331,355	n/a
6.	Average Net Investment		67,782,810	67,504,473	67,226,136	66,987,738	66,749,221	66,470,644	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		520,854	518,716	516,577	514,745	512,912	510,772	6,263,069
	b. Debt Component (Line 6 x 1.8767% x 1/12)		106,006	105,570	105,135	104,762	104,389	103,953	1,274,675
8.	Investment Expenses								
	a. Depreciation (E)		278,337	278,337	278,337	278,457	278,577	278,577	3,339,530
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$905,197	$902,623	$900,049	$897,964	$895,879	$893,302	$10,877,274

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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)	$492,916	492,916	492,916	492,916	492,916	492,916	492,916	n/a
3.	Less: Accumulated Depreciation (C)	$29,390	30,499	31,608	32,717	33,826	34,935	36,044	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$463,526	$462,417	$461,308	$460,199	$459,090	$457,981	$456,872	n/a
6.	Average Net Investment		462,972	461,863	460,754	459,645	458,536	457,427	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,558	3,549	3,541	3,532	3,523	3,515	$21,217
	b. Debt Component (Line 6 x 1.8767% x 1/12)		724	722	721	719	717	715	$4,318
8.	Investment Expenses								
	a. Depreciation (E)		1,109	1,109	1,109	1,109	1,109	1,109	$6,654
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$5,391	$5,380	$5,370	$5,360	$5,350	$5,339	$32,190

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

37

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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)	$492,916	492,916	492,916	492,916	492,916	492,916	492,916	n/a
3.	Less: Accumulated Depreciation (C)	$36,044	37,154	38,263	39,372	40,481	41,590	42,699	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$456,872	$455,763	$454,654	$453,545	$452,436	$451,327	$450,218	n/a
6.	Average Net Investment		456,317	455,208	454,099	452,990	451,881	450,772	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,506	3,498	3,489	3,481	3,472	3,464	42,128
	b. Debt Component (Line 6 x 1.8767% x 1/12)		714	712	710	708	707	705	8,574
8.	Investment Expenses								
	a. Depreciation (E)		1,109	1,109	1,109	1,109	1,109	1,109	13,309
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$5,329	$5,319	$5,309	$5,298	$5,288	$5,278	$64,011

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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		$3,554,462	$12,474,093	$10,248,533	$12,476,935	$11,750,148	$9,883,379	$60,387,550
	b. Clearings to Plant		$6,942,997	$3,802,115	$162,697	$19,218,342	$4,809,983	$5,532,114	$40,468,248
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$113,734,550	120,677,547	124,479,662	124,642,359	143,860,700	148,670,684	154,202,797	n/a
3.	Less: Accumulated Depreciation (C)	$1,494,613	1,713,698	1,941,279	2,171,343	2,438,096	2,750,529	3,081,522	n/a
4.	CWIP - Non Interest Bearing	$161,374,424	157,985,889	166,657,867	176,743,703	170,002,296	176,942,461	181,293,727	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$273,614,361	$276,949,738	$289,196,250	$299,214,718	$311,424,900	$322,862,616	$332,415,001	n/a
6.	Average Net Investment		275,282,050	283,072,994	294,205,484	305,319,809	317,143,758	327,638,809	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		2,115,313	2,175,180	2,260,724	2,346,129	2,436,986	2,517,632	$13,851,964
	b. Debt Component (Line 6 x 1.8767% x 1/12)		430,514	442,698	460,108	477,490	495,981	512,394	$2,819,185
8.	Investment Expenses								
	a. Depreciation (E)		219,085	227,582	230,064	266,753	312,432	330,994	$1,586,910
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$2,764,912	$2,845,460	$2,950,897	$3,090,371	$3,245,399	$3,361,019	$18,258,058

Notes:

(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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		$9,235,010	$8,510,885	$9,069,004	$10,326,584	$10,848,023	$29,844,809	$138,221,865
	b. Clearings to Plant		$30,638	$0	$19,606	$19,606	$5,213,492	$7,398,214	$53,149,804
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$154,202,797	154,233,435	154,233,435	154,253,041	154,272,647	159,486,140	166,884,354	n/a
3.	Less: Accumulated Depreciation (C)	$3,081,522	3,421,888	3,762,307	4,102,740	4,443,202	4,788,280	5,145,445	n/a
4.	CWIP - Non Interest Bearing	$181,293,727	190,498,098	199,008,983	208,058,381	218,365,359	223,999,890	246,446,485	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$332,415,001	$341,309,645	$349,480,112	$358,208,683	$368,194,805	$378,697,750	$408,185,394	n/a
6.	Average Net Investment		336,862,323	345,394,879	353,844,398	363,201,744	373,446,277	393,441,572	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		2,588,507	2,654,072	2,719,000	2,790,903	2,869,624	3,023,271	30,497,340
	b. Debt Component (Line 6 x 1.8767% x 1/12)		526,819	540,163	553,377	568,011	584,033	615,303	6,206,891
8.	Investment Expenses								
	a. Depreciation (E)		340,366	340,418	340,433	340,462	345,078	357,165	3,650,832
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$3,455,692	$3,534,654	$3,612,810	$3,699,377	$3,798,735	$3,995,739	$40,355,064

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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		$0	$530,004	$1,987,113	$2,094,395	$0	$0	$4,611,512
	b. Clearings to Plant		$0	$0	$0	$96,586,824	$1,405,871	$1,378,650	$99,371,345
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	96,586,824	97,992,695	99,371,345	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	76,465	230,507	386,753	n/a
4.	CWIP - Non Interest Bearing	$91,975,312	91,975,312	92,505,316	94,492,429	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$91,975,312	$91,975,312	$92,505,316	$94,492,429	$96,510,359	$97,762,188	$98,984,592	n/a
6.	Average Net Investment		91,975,312	92,240,314	93,498,872	95,501,394	97,136,274	98,373,390	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		706,754	708,790	718,461	733,849	746,411	755,918	$4,370,183
	b. Debt Component (Line 6 x 1.8767% x 1/12)		143,840	144,255	146,223	149,355	151,911	153,846	$889,430
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	76,465	154,042	156,247	$386,753
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$850,594	$853,045	$864,684	$959,668	$1,052,365	$1,066,010	$5,646,366

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

41

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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		$0	$0	$0	$0	$0	$0	$4,611,512
	b. Clearings to Plant		$1,497,140	$1,569,195	$1,458,711	$1,162,485	$917,499	$4,200,510	$110,176,885
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$99,371,345	100,868,485	102,437,680	103,896,391	105,058,876	105,976,375	110,176,885	n/a
3.	Less: Accumulated Depreciation (C)	$386,753	545,276	706,227	869,575	1,034,998	1,202,067	1,373,189	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$98,984,592	$100,323,208	$101,731,453	$103,026,816	$104,023,878	$104,774,307	$108,803,696	n/a
6.	Average Net Investment		99,653,900	101,027,331	102,379,134	103,525,347	104,399,093	106,789,002	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		765,757	776,311	786,698	795,506	802,220	820,585	9,117,260
	b. Debt Component (Line 6 x 1.8767% x 1/12)		155,849	157,997	160,111	161,903	163,270	167,007	1,855,566
8.	Investment Expenses								
	a. Depreciation (E)		158,523	160,951	163,348	165,423	167,070	171,121	1,373,189
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,080,129	$1,095,258	$1,110,157	$1,122,832	$1,132,559	$1,158,713	$12,346,015

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

42

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

Return on Capital Investments, Depreciation and Taxes
For Project:St. Lucie Cooling Water System Inspection (Project No. 34)
(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	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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

Return on Capital Investments, Depreciation and Taxes
For Project:St. Lucie Cooling Water System Inspection (Project No. 34)
(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	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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

Return on Capital Investments, Depreciation and Taxes
For Project:Martin Water Comp (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	$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)	$235,419	235,419	235,419	235,419	235,419	235,419	235,419	n/a
3.	Less: Accumulated Depreciation (C)	$3,767	4,101	4,434	4,768	5,101	5,435	5,768	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$231,652	$231,318	$230,985	$230,651	$230,318	$229,984	$229,651	n/a
6.	Average Net Investment		231,485	231,152	230,818	230,485	230,151	229,817	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		1,779	1,776	1,774	1,771	1,769	1,766	$10,634
	b. Debt Component (Line 6 x 1.8767% x 1/12)		362	361	361	360	360	359	$2,164
8.	Investment Expenses								
	a. Depreciation (E)		334	334	334	334	334	334	$2,001
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$2,474	$2,471	$2,468	$2,465	$2,462	$2,459	$14,800

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

Return on Capital Investments, Depreciation and Taxes
For Project:Martin Water Comp (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	$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)	$235,419	235,419	235,419	235,419	235,419	235,419	235,419	n/a
3.	Less: Accumulated Depreciation (C)	$5,768	6,102	6,435	6,769	7,102	7,436	7,769	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$229,651	$229,317	$228,984	$228,650	$228,317	$227,983	$227,650	n/a
6.	Average Net Investment		229,484	229,150	228,817	228,483	228,150	227,816	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		1,763	1,761	1,758	1,756	1,753	1,751	21,176
	b. Debt Component (Line 6 x 1.8767% x 1/12)		359	358	358	357	357	356	4,310
8.	Investment Expenses								
	a. Depreciation (E)		334	334	334	334	334	334	4,002
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$2,456	$2,453	$2,450	$2,447	$2,443	$2,440	$29,488

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Low Level Rad Waste - LLW (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	$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)	$5,288,004	5,288,004	5,288,004	5,288,004	5,288,004	5,288,004	5,288,004	n/a
3.	Less: Accumulated Depreciation (C)	$2,900	8,699	14,498	20,298	26,097	31,896	37,696	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$5,285,104	$5,279,305	$5,273,506	$5,267,706	$5,261,907	$5,256,108	$5,250,308	n/a
6.	Average Net Investment		5,282,205	5,276,405	5,270,606	5,264,807	5,259,007	5,253,208	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		40,589	40,545	40,500	40,456	40,411	40,367	$242,868
	b. Debt Component (Line 6 x 1.8767% x 1/12)		8,261	8,252	8,243	8,234	8,225	8,215	$49,429
8.	Investment Expenses								
	a. Depreciation (E)		5,799	5,799	5,799	5,799	5,799	5,799	$34,796
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$54,650	$54,596	$54,542	$54,489	$54,435	$54,381	$327,093

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Low Level Rad Waste - LLW (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	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$4,652,357	$0	$0	$4,652,357
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$5,288,004	5,288,004	5,288,004	5,288,004	9,940,361	9,940,361	9,940,361	n/a
3.	Less: Accumulated Depreciation (C)	$37,696	43,495	49,294	55,094	63,607	74,834	86,061	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$5,250,308	$5,244,509	$5,238,710	$5,232,910	$9,876,754	$9,865,527	$9,854,300	n/a
6.	Average Net Investment		5,247,409	5,241,609	5,235,810	7,554,832	9,871,141	9,859,914	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		40,322	40,277	40,233	58,053	75,851	75,765	573,369
	b. Debt Component (Line 6 x 1.8767% x 1/12)		8,206	8,197	8,188	11,815	15,437	15,420	116,693
8.	Investment Expenses								
	a. Depreciation (E)		5,799	5,799	5,799	8,513	11,227	11,227	83,161
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$54,328	$54,274	$54,220	$78,381	$102,516	$102,412	$773,224

Notes:

(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Desoto Next Generation Solar Energy Center (Project No. 37)
(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	$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)	$151,720,737	151,720,737	151,720,737	151,720,737	151,720,737	151,720,737	151,720,737	n/a
3.	Less: Accumulated Depreciation (C)	$619,610	1,036,755	1,453,900	1,871,044	2,288,189	2,705,334	3,122,479	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$151,101,127	$150,683,982	$150,266,837	$149,849,692	$149,432,547	$149,015,403	$148,598,258	n/a
6.	Average Net Investment		150,892,555	150,475,410	150,058,265	149,641,120	149,223,975	148,806,830	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		1,159,484	1,156,278	1,153,073	1,149,867	1,146,662	1,143,457	$6,908,821
	b. Debt Component (Line 6 x 1.8767% x 1/12)		235,981	235,328	234,676	234,024	233,371	232,719	$1,406,100
8.	Investment Expenses								
	a. Depreciation (E)		417,145	417,145	417,145	417,145	417,145	417,145	$2,502,869
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,812,609	$1,808,752	$1,804,894	$1,801,036	$1,797,178	$1,793,321	$10,817,790

Notes:

(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Desoto Next Generation Solar Energy Center (Project No. 37)
(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)	$151,720,737	151,720,737	151,720,737	151,720,737	151,720,737	151,720,737	151,720,737	n/a
3.	Less: Accumulated Depreciation (C)	$3,122,479	3,539,624	3,956,769	4,373,914	4,791,059	5,208,203	5,625,348	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$148,598,258	$148,181,113	$147,763,968	$147,346,823	$146,929,678	$146,512,533	$146,095,389	n/a
6.	Average Net Investment		148,389,685	147,972,540	147,555,396	147,138,251	146,721,106	146,303,961	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		1,140,251	1,137,046	1,133,840	1,130,635	1,127,430	1,124,224	13,702,247
	b. Debt Component (Line 6 x 1.8767% x 1/12)		232,067	231,414	230,762	230,110	229,457	228,805	2,788,714
8.	Investment Expenses								
	a. Depreciation (E)		417,145	417,145	417,145	417,145	417,145	417,145	5,005,738
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,789,463	$1,785,605	$1,781,747	$1,777,889	$1,774,032	$1,770,174	$21,496,699

Notes:

(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Space Coast Next Generation Solar Energy Center (Project No. 38)
(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		1,423,110.00	8,293,808.00	8,445,210.00	8,445,862.00	13,809,447.00	5,789,000.00	$46,206,437
	b. Clearings to Plant		$0	$0	$0	$0	$0	$78,041,342	$78,041,342
	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	78,041,342	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	107,307	n/a
4.	CWIP - Non Interest Bearing	$31,834,905	33,258,015	41,551,823	49,997,033	58,442,895	72,252,342	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$31,834,905	$33,258,015	$41,551,823	$49,997,033	$58,442,895	$72,252,342	$77,934,035	n/a
6.	Average Net Investment		32,546,460	37,404,919	45,774,428	54,219,964	65,347,619	75,093,189	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		250,092	287,426	351,738	416,635	502,142	577,029	$2,385,063
	b. Debt Component (Line 6 x 1.8767% x 1/12)		50,899	58,498	71,587	84,795	102,197	117,438	$485,414
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	107,307	$107,307
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$300,992	$345,923	$423,325	$501,430	$604,339	$801,774	$2,977,783

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Space Coast Next Generation Solar Energy Center (Project No. 38)
(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	-	$46,206,437
b.	Clearings to Plant		$865,625	$0	$0	$0	$0	$0	$78,906,967
c.	Retirements		$0	$0	$0	$0	$0	$0	$0
d.	Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$78,041,342	78,906,967	78,906,967	78,906,967	78,906,967	78,906,967	78,906,967	n/a
3.	Less: Accumulated Depreciation (C)	$107,307	323,111	540,105	757,099	974,093	1,191,087	1,408,082	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$77,934,035	$78,583,856	$78,366,862	$78,149,868	$77,932,874	$77,715,880	$77,498,886	n/a
6.	Average Net Investment		78,258,946	78,475,359	78,258,365	78,041,371	77,824,377	77,607,383	n/a
7.	Return on Average Net Investment								
a.	Equity Component grossed up for taxes (D)		601,355	603,018	601,350	599,683	598,016	596,348	5,984,832
b.	Debt Component (Line 6 x 1.8767% x 1/12)		122,389	122,728	122,388	122,049	121,710	121,370	1,218,047
8.	Investment Expenses								
a.	Depreciation (E)		215,804	216,994	216,994	216,994	216,994	216,994	1,408,082
b.	Amortization (F)								
c.	Dismantlement								
d.	Property Expenses								
e.	Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$939,548	$942,740	$940,733	$938,726	$936,719	$934,712	$8,610,961

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Martin Next Generation Solar Energy Center (Project No. 39)
(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		41,481,705.00	30,319,638.00	24,316,768.00	20,495,262.00	15,416,260.00	17,295,451.00	$149,325,084
	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)	$1,306,266	1,306,266	1,306,266	1,306,266	1,306,266	1,306,266	1,306,266	n/a
3.	Less: Accumulated Depreciation (C)	$20,583	24,738	28,892	33,046	37,200	41,354	45,509	n/a
4.	CWIP - Non Interest Bearing	$213,190,493	254,672,198	284,991,836	309,308,604	329,803,866	345,220,126	362,515,577	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$214,476,176	$255,953,727	$286,269,211	$310,581,824	$331,072,932	$346,485,038	$363,776,335	n/a
6.	Average Net Investment		235,214,951	271,111,469	298,425,517	320,827,378	338,778,985	355,130,686	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		1,807,431	2,083,266	2,293,152	2,465,291	2,603,235	2,728,884	$13,981,258
	b. Debt Component (Line 6 x 1.8767% x 1/12)		367,853	423,991	466,708	501,742	529,816	555,389	$2,845,499
8.	Investment Expenses								
	a. Depreciation (E)		4,154	4,154	4,154	4,154	4,154	4,154	$24,925
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$2,179,438	$2,511,411	$2,764,014	$2,971,188	$3,137,205	$3,288,427	$16,851,683

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Martin Next Generation Solar Energy Center (Project No. 39)
(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		13,769,843.00	14,608,623.00	8,240,643.00	12,275,565.00	6,861,371.00	8,010,892.00	$213,092,021
	b. Clearings to Plant		$0	$0	$0	$0	$0	$426,282,514	$426,282,514
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$1,306,266	1,306,266	1,306,266	1,306,266	1,306,266	1,306,266	427,588,780	n/a
3.	Less: Accumulated Depreciation (C)	$45,509	49,663	53,817	57,971	62,125	66,280	656,572	n/a
4.	CWIP - Non Interest Bearing	$362,515,577	376,285,420	390,894,043	399,134,686	411,410,251	418,271,622	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$363,776,335	$377,542,024	$392,146,492	$400,382,981	$412,654,392	$419,511,609	$426,932,208	n/a
6.	Average Net Investment		370,659,179	384,844,258	396,264,737	406,518,687	416,083,000	423,221,908	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		2,848,207	2,957,208	3,044,965	3,123,758	3,197,252	3,252,108	32,404,756
	b. Debt Component (Line 6 x 1.8767% x 1/12)		579,674	601,858	619,718	635,755	650,712	661,877	6,595,093
8.	Investment Expenses								
	a. Depreciation (E)		4,154	4,154	4,154	4,154	4,154	590,293	635,989
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$3,432,035	$3,563,220	$3,668,837	$3,763,667	$3,852,118	$4,504,278	$39,635,837

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Temporary Heating System (Project No. 41)
(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	$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)	$4,688,928	4,688,928	4,688,928	4,688,928	4,688,928	4,688,928	4,688,928	n/a
3.	Less: Accumulated Depreciation (C)	$1,172	3,517	5,861	8,206	10,550	12,895	15,239	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$4,687,756	$4,685,411	$4,683,067	$4,680,722	$4,678,378	$4,676,033	$4,673,689	n/a
6.	Average Net Investment		4,686,584	4,684,239	4,681,895	4,679,550	4,677,206	4,674,861	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		36,012	35,994	35,976	35,958	35,940	35,922	$215,805
	b. Debt Component (Line 6 x 1.8767% x 1/12)		7,329	7,326	7,322	7,318	7,315	7,311	$43,921
8.	Investment Expenses								
	a. Depreciation (E)		2,344	2,344	2,344	2,344	2,344	2,344	$14,067
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$45,686	$45,665	$45,643	$45,621	$45,600	$45,578	$273,793

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Temporary Heating System (Project No. 41)
(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	$4,660,000	$20,000	$0	$0	$4,680,000
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$4,688,928	4,688,928	4,688,928	9,348,928	9,368,928	9,368,928	9,368,928	n/a
3.	Less: Accumulated Depreciation (C)	$15,239	17,583	19,928	23,632	28,700	33,775	38,849	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$4,673,689	$4,671,345	$4,669,000	$9,325,296	$9,340,228	$9,335,153	$9,330,079	n/a
6.	Average Net Investment		4,672,517	4,670,172	6,997,148	9,332,762	9,337,691	9,332,616	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		35,904	35,886	53,767	71,715	71,752	71,713	556,543
	b. Debt Component (Line 6 x 1.8767% x 1/12)		7,307	7,304	10,943	14,596	14,603	14,595	113,269
8.	Investment Expenses								
	a. Depreciation (E)		2,344	2,344	3,704	5,069	5,074	5,074	37,677
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$45,556	$45,535	$68,414	$91,379	$91,430	$91,383	$707,489

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Turkey Point Cooling Canal Monitoring (Project No. 42)
(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	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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Turkey Point Cooling Canal Monitoring (Project No. 42)
(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	$2,600,000	$0	$0	$0	$0	$2,600,000
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	2,600,000	2,600,000	2,600,000	2,600,000	2,600,000	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	1,192	3,575	5,958	8,342	10,725	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	$2,598,808	$2,596,425	$2,594,042	$2,591,658	$2,589,275	n/a
6.	Average Net Investment		0	1,299,404	2,597,617	2,595,233	2,592,850	2,590,467	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	9,985	19,961	19,942	19,924	19,906	89,717
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	2,032	4,062	4,059	4,055	4,051	18,259
8.	Investment Expenses								
	a. Depreciation (E)		0	1,192	2,383	2,383	2,383	2,383	10,725
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$13,209	$26,406	$26,384	$26,362	$26,340	$118,701

Notes:
(A) N/A
(B) 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 55-59.
(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 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

Return on Capital Investments, Depreciation and Taxes
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	Six Month 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	(2,182,832)	(2,168,371)	(2,153,910)	(2,139,449)	(2,091,431)	(2,210,245)	(2,189,073)	
2	Total Working Capital	($2,182,832)	($2,168,371)	($2,153,910)	($2,139,449)	($2,091,431)	($2,210,245)	($2,189,073)	
3	Average Net Working Capital Balance		(2,175,602)	(2,161,141)	(2,146,680)	(2,115,440)	(2,150,838)	(2,199,659)	
4	Return on Average Net Working Capital Balance								
a	Equity Component grossed up for taxes (A)		(16,718)	(16,607)	(16,495)	(16,255)	(16,527)	(16,903)	
b	Debt Component (Line 6 x 1.6698% x 1/12)		(3,402)	(3,380)	(3,357)	(3,308)	(3,364)	(3,440)	
5	Total Return Component		($20,120)	($19,986)	($19,853)	($19,564)	($19,891)	($20,343)	($119,757) (D)
6	Expense Dr (Cr)								
a	411.800 Gains from Dispositions of Allowances		(14,461)	(14,461)	(14,461)	(48,018)	(21,172)	(21,172)	
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)		($14,461)	($14,461)	($14,461)	($48,018)	($21,172)	($21,172)	($133,745) (E)
8	Total System Recoverable Expenses (Lines 5+7)		(34,581)	(34,447)	(34,314)	(67,582)	(41,063)	(41,515)	
a	Recoverable Costs Allocated to Energy		(34,581)	(34,447)	(34,314)	(67,582)	(41,063)	(41,515)	
b	Recoverable Costs Allocated to Demand		0	0	0	0	0	0	
9	Energy Jurisdictional Factor		98.69261%	98.69261%	98.69261%	98.69261%	98.69261%	98.69261%	
10	Demand Jurisdictional Factor		98.76729%	98.76729%	98.76729%	98.76729%	98.76729%	98.76729%	
11	Retail Energy-Related Recoverable Costs (B)		(34,129)	(33,997)	(33,865)	(66,698)	(40,527)	(40,972)	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($34,129)	($33,997)	($33,865)	($66,698)	($40,527)	($40,972)	

Notes:

(A) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.2013% reflects an 11% return on equity.
(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule
(E) Line 7 is reported on O&M Schedule

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

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

Return on Capital Investments, Depreciation and Taxes
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	Twelve Month 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	($2,096,067)	(2,074,895)	(2,053,722)	(2,032,550)	(2,011,378)	(1,990,205)	(1,969,033)	
2	Total Working Capital	($2,096,067)	($2,074,895)	($2,053,722)	($2,032,550)	($2,011,378)	($1,990,205)	($1,969,033)	
3	Average Net Working Capital Balance		(2,085,481)	(2,064,308)	(2,043,136)	(2,021,964)	(2,000,792)	(1,979,619)	
4	Return on Average Net Working Capital Balance								
a	Equity Component grossed up for taxes (A)		(16,025)	(15,862)	(15,700)	(15,537)	(15,374)	(15,212)	
b	Debt Component (Line 6 x 1.6698% x 1/12)		(3,261)	(3,228)	(3,195)	(3,162)	(3,129)	(3,096)	
5	Total Return Component		($19,287)	($19,091)	($18,895)	($18,699)	($18,503)	($18,308)	($232,540) (D)
6	Expense Dr (Cr)								
a	411.800 Gains from Dispositions of Allowances		(21,172)	(21,172)	(21,172)	(21,172)	(21,172)	(21,172)	
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)		($21,172)	($21,172)	($21,172)	($21,172)	($21,172)	($21,172)	($260,779) (E)
8	Total System Recoverable Expenses (Lines 5+7)		(40,459)	(40,263)	(40,067)	(39,872)	(39,676)	(39,480)	
a	Recoverable Costs Allocated to Energy		(40,459)	(40,263)	(40,067)	(39,872)	(39,676)	(39,480)	
b	Recoverable Costs Allocated to Demand		0	0	0	0	0	0	
9	Energy Jurisdictional Factor		98.69261%	98.69261%	98.69261%	98.69261%	98.69261%	98.69261%	
10	Demand Jurisdictional Factor		98.76729%	98.76729%	98.76729%	98.76729%	98.76729%	98.76729%	
11	Retail Energy-Related Recoverable Costs (B)		(39,930)	(39,737)	(39,544)	(39,350)	(39,157)	(38,964)	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($39,930)	($39,737)	($39,544)	($39,350)	($39,157)	($38,964)	

Notes:

(A) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.2013% reflects an 11% return on equity.
(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule
(E) Line 7 is reported on O&M Schedule

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

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
2010 Annual Capital Depreciation Schedule

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Estimated Balance December 2009	Estimated Balance December 2010
02 - Low NOX Burner Technology						
	02 - Steam Generation Plant	Pt Everglades U1	31200	6.70%	2,689,232.57	2,689,232.57
	02 - Steam Generation Plant	Pt Everglades U2	31200	6.10%	2,368,972.27	2,368,972.27
	02 - Steam Generation Plant	Riviera U3	31200	1.70%	3,815,802.70	3,815,802.70
	02 - Steam Generation Plant	Riviera U4	31200	1.40%	3,246,925.80	3,246,925.80
	02 - Steam Generation Plant	Turkey Pt U1	31200	2.00%	2,925,027.84	2,925,027.84
	02 - Steam Generation Plant	Turkey Pt U2	31200	1.80%	2,275,221.65	2,275,221.65
02 - Low NOX Burner Technology Total					**17,321,182.83**	**17,321,182.83**
03 - Continuous Emission Monitoring						
	02 - Steam Generation Plant	Cape Canaveral Comm	31100	1.70%	59,227.10	59,227.10
	02 - Steam Generation Plant	Cape Canaveral Comm	31200	1.30%	44,644.65	44,644.65
	02 - Steam Generation Plant	Cape Canaveral U1	31200	1.40%	325,165.05	325,165.05
	02 - Steam Generation Plant	Cape Canaveral U2	31200	1.10%	345,150.96	345,150.96
	02 - Steam Generation Plant	Cutler Comm	31100	0.00%	64,883.87	64,883.87
	02 - Steam Generation Plant	Cutler Comm	31200	0.50%	36,276.52	36,276.52
	02 - Steam Generation Plant	Cutler U5	31200	0.20%	310,454.41	310,454.41
	02 - Steam Generation Plant	Cutler U6	31200	1.00%	311,861.95	311,861.95
	02 - Steam Generation Plant	Manatee Comm	31200	14.10%	31,859.00	31,859.00
	02 - Steam Generation Plant	Manatee U1	31100	4.10%	56,430.25	56,430.25
	02 - Steam Generation Plant	Manatee U1	31200	4.80%	462,142.42	462,142.42
	02 - Steam Generation Plant	Manatee U2	31100	4.10%	56,332.75	56,332.75
	02 - Steam Generation Plant	Manatee U2	31200	4.00%	508,552.43	508,552.43
	02 - Steam Generation Plant	Martin Comm	31200	4.10%	31,631.74	31,631.74
	02 - Steam Generation Plant	Martin U1	31100	1.50%	36,810.86	36,810.86
	02 - Steam Generation Plant	Martin U1	31200	1.80%	529,318.55	529,318.55
	02 - Steam Generation Plant	Martin U2	31100	1.50%	36,845.37	36,845.37
	02 - Steam Generation Plant	Martin U2	31200	1.50%	525,201.70	525,201.70
	02 - Steam Generation Plant	Pt Everglades Comm	31100	2.70%	127,911.34	127,911.34
	02 - Steam Generation Plant	Pt Everglades Comm	31200	2.20%	67,787.69	67,787.69
	02 - Steam Generation Plant	Pt Everglades U1	31200	6.70%	458,060.74	458,060.74
	02 - Steam Generation Plant	Pt Everglades U2	31200	6.10%	480,321.84	480,321.84
	02 - Steam Generation Plant	Pt Everglades U3	31200	4.00%	507,658.33	507,658.33
	02 - Steam Generation Plant	Pt Everglades U4	31200	3.60%	517,303.41	517,303.41
	02 - Steam Generation Plant	Riviera Comm	31100	1.90%	60,973.18	60,973.18
	02 - Steam Generation Plant	Riviera Comm	31200	0.40%	11,495.25	11,495.25
	02 - Steam Generation Plant	Riviera U3	31200	1.70%	453,591.63	453,591.63
	02 - Steam Generation Plant	Riviera U4	31200	1.40%	437,621.87	437,621.87
	02 - Steam Generation Plant	Sanford U3	31100	4.00%	54,282.08	54,282.08
	02 - Steam Generation Plant	Sanford U3	31200	3.60%	426,269.85	426,269.85
	02 - Steam Generation Plant	Scherer U4	31200	1.90%	515,653.32	515,653.32
	02 - Steam Generation Plant	SJRPP - Comm	31100	3.10%	43,193.33	43,193.33
	02 - Steam Generation Plant	SJRPP U1	31200	2.20%	779.50	779.50
	02 - Steam Generation Plant	SJRPP U2	31200	2.30%	779.51	779.51
	02 - Steam Generation Plant	Turkey Pt Comm	31100	2.30%	59,056.19	59,056.19
	02 - Steam Generation Plant	Turkey Pt Comm	31200	2.10%	37,954.50	37,954.50
	02 - Steam Generation Plant	Turkey Pt U1	31200	2.00%	545,584.31	545,584.31
	02 - Steam Generation Plant	Turkey Pt U2	31200	1.80%	504,688.53	504,688.53
	05 - Other Generation Plant	Ft Lauderdale Comm	34100	4.10%	58,859.79	58,859.79
	05 - Other Generation Plant	Ft Lauderdale Comm	34500	4.10%	34,502.21	34,502.21
	05 - Other Generation Plant	Ft Lauderdale U4	34300	5.00%	462,254.20	462,254.20
	05 - Other Generation Plant	Ft Lauderdale U5	34300	3.70%	473,359.99	473,359.99
	05 - Other Generation Plant	Ft Myers U2	34300	5.50%	21,625.54	21,625.54
	05 - Other Generation Plant	Ft Myers U3	34300	5.60%	5,000.00	5,000.00
	05 - Other Generation Plant	Martin U3	34300	5.80%	418,050.66	418,050.66
	05 - Other Generation Plant	Martin U4	34300	5.70%	410,652.42	410,652.42
	05 - Other Generation Plant	Martin U8	34300	5.50%	4,688.46	4,688.46
	05 - Other Generation Plant	Putnam Comm	34100	4.10%	82,857.82	82,857.82
	05 - Other Generation Plant	Putnam Comm	34300	6.30%	3,138.97	3,138.97
	05 - Other Generation Plant	Putnam U1	34300	5.20%	331,926.69	331,926.69
	05 - Other Generation Plant	Putnam U2	34300	5.40%	365,670.68	365,670.68
	05 - Other Generation Plant	Sanford U4	34300	5.60%	83,849.32	83,849.32
	05 - Other Generation Plant	Sanford U5	34300	5.70%	41,989.84	41,989.84
03 - Continuous Emission Monitoring Total					**11,882,182.57**	**11,882,182.57**

Florida Power & Light Company
Environmental Cost Recovery Clause
2010 Annual Capital Depreciation Schedule

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Estimated Balance December 2009	Estimated Balance December 2010
04 - Clean Closure Equivalency Demonstration						
	02 - Steam Generation Plant	Cape Canaveral Comm	31100	1.70%	17,254.20	17,254.20
	02 - Steam Generation Plant	Pt Everglades Comm	31100	2.70%	19,812.30	19,812.30
	02 - Steam Generation Plant	Turkey Pt Comm	31100	2.30%	21,799.28	21,799.28
04 - Clean Closure Equivalency Demonstration Total					**58,865.78**	**58,865.78**
05 - Maintenance of Above Ground Fuel Tanks						
	02 - Steam Generation Plant	Cape Canaveral Comm	31100	1.70%	901,636.88	901,636.88
	02 - Steam Generation Plant	Manatee Comm	31100	4.90%	3,111,263.35	3,111,263.35
	02 - Steam Generation Plant	Manatee Comm	31200	14.10%	219,543.23	219,543.23
	02 - Steam Generation Plant	Manatee U1	31200	4.80%	104,845.35	104,845.35
	02 - Steam Generation Plant	Manatee U2	31200	4.00%	127,429.19	127,429.19
	02 - Steam Generation Plant	Martin Comm	31100	1.70%	1,110,450.32	1,110,450.32
	02 - Steam Generation Plant	Martin Comm	31200	4.10%	94,671.98	94,671.98
	02 - Steam Generation Plant	Martin U1	31100	1.50%	176,338.83	176,338.83
	02 - Steam Generation Plant	Pt Everglades Comm	31100	2.70%	1,132,078.22	1,132,078.22
	02 - Steam Generation Plant	Riviera Comm	31100	1.90%	1,081,354.77	1,081,354.77
	02 - Steam Generation Plant	Sanford U3	31100	4.00%	796,754.11	796,754.11
	02 - Steam Generation Plant	SJRPP - Comm	31100	3.10%	42,091.24	42,091.24
	02 - Steam Generation Plant	SJRPP - Comm	31200	2.00%	2,292.39	2,292.39
	02 - Steam Generation Plant	Turkey Pt Comm	31100	2.30%	87,566.23	87,566.23
	02 - Steam Generation Plant	Turkey Pt U2	31100	2.10%	42,158.96	42,158.96
	05 - Other Generation Plant	Ft Lauderdale Comm	34200	4.40%	898,110.65	898,110.65
	05 - Other Generation Plant	Ft Lauderdale GTs	34200	4.50%	584,290.23	584,290.23
	05 - Other Generation Plant	Ft Myers GTs	34200	5.00%	68,893.65	68,893.65
	05 - Other Generation Plant	Pt Everglades GTs	34200	5.10%	2,359,099.94	2,359,099.94
	05 - Other Generation Plant	Putnam Comm	34200	3.70%	749,025.94	749,025.94
05 - Maintenance of Above Ground Fuel Tanks Total					**13,689,895.46**	**13,689,895.46**
07 - Relocate Turbine Lube Oil Piping						
	03 - Nuclear Generation Plant	St Lucie U1	32300	1.20%	31,030.00	31,030.00
07 - Relocate Turbine Lube Oil Piping Total					**31,030.00**	**31,030.00**
08 - Oil Spill Clean-up/Response Equipment						
	02 - Steam Generation Plant	Amortizable	31650	5-Year	73,157.49	73,157.49
	02 - Steam Generation Plant	Amortizable	31670	7-Year	377,484.82	461,981.63
	02 - Steam Generation Plant	Martin Comm	31600	3.20%	23,107.32	23,107.32
	02 - Steam Generation Plant	Pt Everglades Comm	31100	2.70%	56,000.00	56,000.00
	02 - Steam Generation Plant	Sanford Comm	31100	4.00%	0.00	112,000.00
	05 - Other Generation Plant	Amortizable	34650	5-Year	23,274.60	23,274.60
	05 - Other Generation Plant	Amortizable	34670	7-Year	45,699.54	43,232.74
	08 - General Plant	Amortizable	39190	3-Year	1,943.47	0.00
08 - Oil Spill Clean-up/Response Equipment Total					**600,667.24**	**792,753.78**
10 - Reroute Storm Water Runoff						
	03 - Nuclear Generation Plant	St Lucie Comm	32100	1.40%	117,793.83	117,793.83
10 - Reroute Storm Water Runoff Total					**117,793.83**	**117,793.83**
12 - Scherer Discharge Pipline						
	02 - Steam Generation Plant	Scherer Comm	31000	0.00%	9,936.72	9,936.72
	02 - Steam Generation Plant	Scherer Comm	31100	1.60%	524,872.97	524,872.97
	02 - Steam Generation Plant	Scherer Comm	31200	1.60%	328,761.62	328,761.62
	02 - Steam Generation Plant	Scherer Comm	31400	1.00%	689.11	689.11
12 - Scherer Discharge Pipline Total					**864,260.42**	**864,260.42**
20 - Wastewater/Stormwater Discharge Elimination						
	02 - Steam Generation Plant	Cape Canaveral Comm	31100	1.70%	706,500.94	706,500.94
	02 - Steam Generation Plant	Martin U1	31200	1.80%	380,994.77	380,994.77
	02 - Steam Generation Plant	Martin U2	31200	1.50%	416,671.92	416,671.92
	02 - Steam Generation Plant	Pt Everglades Comm	31100	2.70%	296,707.34	296,707.34
	02 - Steam Generation Plant	Riviera Comm	31100	1.90%	560,786.81	560,786.81
20 - Wastewater/Stormwater Discharge Elimination Total					**2,361,661.78**	**2,361,661.78**

Florida Power & Light Company
Environmental Cost Recovery Clause
2010 Annual Capital Depreciation Schedule

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Estimated Balance December 2009	Estimated Balance December 2010
21 - St. Lucie Turtle Nets						
	03 - Nuclear Generation Plant	St Lucie Comm	32100	1.40%	286,248.99	286,248.99
21 - St. Lucie Turtle Nets Total					**286,248.99**	**286,248.99**
22 - Pipeline Integrity						
	02 - Steam Generation Plant	Martin Comm	31100	1.70%	0.00	1,200,000.00
22 - Pipeline Integrity Total					**0.00**	**1,200,000.00**
23 - Spill Prevention Clean-Up & Countermeasures						
	02 - Steam Generation Plant	Cape Canaveral Comm	31100	1.70%	689,323.23	689,323.23
	02 - Steam Generation Plant	Cape Canaveral Comm	31400	0.70%	13,451.85	13,451.85
	02 - Steam Generation Plant	Cape Canaveral Comm	31500	1.90%	33,805.48	33,805.48
	02 - Steam Generation Plant	Cutler Comm	31400	0.00%	12,236.00	12,236.00
	02 - Steam Generation Plant	Cutler U5	31400	0.20%	18,388.00	18,388.00
	02 - Steam Generation Plant	Manatee Comm	31100	4.90%	749,860.96	749,860.96
	02 - Steam Generation Plant	Manatee Comm	31500	3.70%	26,325.43	26,325.43
	02 - Steam Generation Plant	Martin Comm	31100	1.70%	343,785.10	343,785.10
	02 - Steam Generation Plant	Martin Comm	31500	1.30%	34,754.74	34,754.74
	02 - Steam Generation Plant	Pt Everglades Comm	31100	2.70%	2,967,759.91	2,967,759.91
	02 - Steam Generation Plant	Pt Everglades Comm	31500	2.30%	7,782.85	7,782.85
	02 - Steam Generation Plant	Pt Everglades U1	31100	2.60%	0.00	75,000.00
	02 - Steam Generation Plant	Pt Everglades U2	31100	2.60%	0.00	75,000.00
	02 - Steam Generation Plant	Pt Everglades U3	31100	2.60%	0.00	75,000.00
	02 - Steam Generation Plant	Pt Everglades U4	31100	2.60%	0.00	75,000.00
	02 - Steam Generation Plant	Riviera Comm	31100	1.90%	205,014.03	205,014.03
	02 - Steam Generation Plant	Riviera U3	31200	1.70%	736,958.97	736,958.97
	02 - Steam Generation Plant	Riviera U4	31200	1.40%	894,298.77	894,298.77
	02 - Steam Generation Plant	Sanford U3	31100	4.00%	850,530.75	850,530.75
	02 - Steam Generation Plant	Sanford U3	31200	3.60%	211,727.22	211,727.22
	02 - Steam Generation Plant	Turkey Pt Comm	31100	2.30%	92,013.09	92,013.09
	02 - Steam Generation Plant	Turkey Pt Comm	31500	2.10%	13,559.00	13,559.00
	03 - Nuclear Generation Plant	St Lucie U1	32300	1.20%	404,835.79	404,835.79
	03 - Nuclear Generation Plant	St Lucie U1	32400	1.70%	437,945.38	698,345.38
	03 - Nuclear Generation Plant	St Lucie U2	32300	1.90%	547,962.04	547,962.04
	05 - Other Generation Plant	Amortizable	34670	7-Year	7,065.10	7,065.10
	05 - Other Generation Plant	Ft Lauderdale Comm	34100	4.10%	189,219.17	189,219.17
	05 - Other Generation Plant	Ft Lauderdale Comm	34200	4.40%	1,480,169.46	1,480,169.46
	05 - Other Generation Plant	Ft Lauderdale Comm	34300	1.80%	28,250.00	28,250.00
	05 - Other Generation Plant	Ft Lauderdale GTs	34100	2.20%	92,726.74	92,726.74
	05 - Other Generation Plant	Ft Lauderdale GTs	34200	4.50%	513,250.07	513,250.07
	05 - Other Generation Plant	Ft Myers Comm	34100	3.50%	0.00	300,000.00
	05 - Other Generation Plant	Ft Myers GTs	34100	2.10%	98,714.92	98,714.92
	05 - Other Generation Plant	Ft Myers GTs	34200	5.00%	629,983.29	629,983.29
	05 - Other Generation Plant	Ft Myers GTs	34500	2.90%	12,430.00	12,430.00
	05 - Other Generation Plant	Ft Myers U2	34300	5.50%	49,727.00	49,727.00
	05 - Other Generation Plant	Ft Myers U3	34500	4.80%	12,430.00	12,430.00
	05 - Other Generation Plant	Martin Comm	34100	3.40%	61,215.95	61,215.95
	05 - Other Generation Plant	Martin U8	34200	4.80%	84,868.00	84,868.00
	05 - Other Generation Plant	Pt Everglades GTs	34100	1.50%	454,080.68	454,080.68
	05 - Other Generation Plant	Pt Everglades GTs	34200	5.10%	1,703,610.61	1,703,610.61
	05 - Other Generation Plant	Pt Everglades GTs	34500	0.60%	7,782.85	7,782.85
	05 - Other Generation Plant	Putnam Comm	34100	4.10%	148,511.20	148,511.20
	05 - Other Generation Plant	Putnam Comm	34200	3.70%	1,713,191.94	1,713,191.94
	05 - Other Generation Plant	Putnam Comm	34500	4.20%	60,746.93	60,746.93
	06 - Transmission Plant - Electric		35200	2.50%	951,562.91	1,005,312.91
	06 - Transmission Plant - Electric		35300	2.80%	177,981.88	177,981.88
	07 - Distribution Plant - Electric		36100	2.60%	2,862,093.44	3,023,343.44
	08 - General Plant		39000	2.70%	12,843.35	12,843.35
23 - Spill Prevention Clean-Up & Countermeasures Total					**20,644,774.08**	**21,720,174.08**
24 - Manatee Reburn						
	02 - Steam Generation Plant	Manatee U1	31200	4.80%	16,771,308.37	16,771,308.37
	02 - Steam Generation Plant	Manatee U2	31200	4.00%	16,027,438.94	16,027,438.94
24 - Manatee Reburn Total					**32,798,747.31**	**32,798,747.31**

Florida Power & Light Company
Environmental Cost Recovery Clause
2010 Annual Capital Depreciation Schedule

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Estimated Balance December 2009	Estimated Balance December 2010
25 - PPE ESP Technology						
	02 - Steam Generation Plant	Pt Everglades Comm	31200	2.20%	36,000.00	36,000.00
	02 - Steam Generation Plant	Pt Everglades U1	31100	2.60%	298,709.93	298,709.93
	02 - Steam Generation Plant	Pt Everglades U1	31200	6.70%	10,492,103.15	10,572,103.15
	02 - Steam Generation Plant	Pt Everglades U1	31500	2.00%	2,500,248.85	2,500,248.85
	02 - Steam Generation Plant	Pt Everglades U1	31600	1.00%	307,032.30	307,032.30
	02 - Steam Generation Plant	Pt Everglades U2	31100	2.60%	184,084.01	184,084.01
	02 - Steam Generation Plant	Pt Everglades U2	31200	6.10%	12,151,519.29	12,151,519.29
	02 - Steam Generation Plant	Pt Everglades U2	31500	2.10%	3,954,581.63	3,954,581.63
	02 - Steam Generation Plant	Pt Everglades U2	31600	1.70%	324,086.94	324,086.94
	02 - Steam Generation Plant	Pt Everglades U3	31100	2.60%	713,693.44	713,693.44
	02 - Steam Generation Plant	Pt Everglades U3	31200	4.00%	18,080,787.51	18,080,787.51
	02 - Steam Generation Plant	Pt Everglades U3	31500	2.20%	4,304,056.69	4,304,056.69
	02 - Steam Generation Plant	Pt Everglades U3	31600	1.00%	528,541.18	528,541.18
	02 - Steam Generation Plant	Pt Everglades U4	31100	2.60%	313,275.79	313,275.79
	02 - Steam Generation Plant	Pt Everglades U4	31200	3.60%	20,474,742.26	20,554,742.26
	02 - Steam Generation Plant	Pt Everglades U4	31500	2.10%	6,729,950.05	6,729,950.05
	02 - Steam Generation Plant	Pt Everglades U4	31600	1.30%	551,535.30	551,535.30
25 - PPE ESP Technology Total					**81,944,948.32**	**82,104,948.32**
26 - UST Remove/Replace						
	08 - General Plant		39000	2.70%	492,916.42	492,916.42
26 - UST Remove/Replace Total					**492,916.42**	**492,916.42**
31 - Clean Air Interstate Rule (CAIR)						
	02 - Steam Generation Plant	Manatee U1	31200	4.80%	0.00	20,669,278.63
	02 - Steam Generation Plant	Manatee U1	31400	3.70%	277,326.13	7,179,345.52
	02 - Steam Generation Plant	Manatee U2	31100	4.10%	0.00	30,638.14
	02 - Steam Generation Plant	Manatee U2	31200	4.00%	13,966,222.30	20,065,821.86
	02 - Steam Generation Plant	Manatee U2	31400	3.00%	7,051,266.58	7,051,266.58
	02 - Steam Generation Plant	Martin U1	31200	1.80%	10,327,159.88	19,528,815.20
	02 - Steam Generation Plant	Martin U1	31400	1.30%	7,694,692.34	7,794,692.34
	02 - Steam Generation Plant	Martin U2	31200	1.50%	13,726,187.02	20,730,282.02
	02 - Steam Generation Plant	Martin U2	31400	0.80%	5,843,761.48	6,693,540.48
	02 - Steam Generation Plant	SJRPP U1	31200	2.20%	27,350,345.33	29,643,084.33
	02 - Steam Generation Plant	SJRPP U2	31200	2.30%	27,221,617.39	27,221,617.39
	05 - Other Generation Plant	Ft Lauderdale GTs	34300	2.20%	110,241.57	110,241.57
	05 - Other Generation Plant	Ft Myers GTs	34300	3.10%	57,855.19	57,855.19
	05 - Other Generation Plant	Pt Everglades GTs	34300	2.60%	107,874.44	107,874.44
31 - Clean Air Interstate Rule (CAIR) Total					**113,734,549.65**	**166,884,353.69**
33 - Clean Air Mercury Rule (CAMR)						
	02 - Steam Generation Plant	Scherer U4	31200	1.90%	0.00	110,176,884.84
33 - Clean Air Mercury Rule (CAMR) Total					**0.00**	**110,176,884.84**
35 - Martin Drinking Water System						
	02 - Steam Generation Plant	Martin Comm	31100	1.70%	235,418.59	235,418.59
35 - Martin Drinking Water System Total					**235,418.59**	**235,418.59**
36 - Low Level Waste Storage						
	03 - Nuclear Generation Plant	St Lucie Comm	32100	1.40%	3,807,997.00	8,460,354.00
	03 - Nuclear Generation Plant	Turkey Pt Comm	32100	1.10%	1,480,007.00	1,480,007.00
36 - Low Level Waste Storage Total					**5,288,004.00**	**9,940,361.00**

Florida Power & Light Company
Environmental Cost Recovery Clause
2010 Annual Capital Depreciation Schedule

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Estimated Balance December 2009	Estimated Balance December 2010
37 - DeSoto Solar Energy Center						
	05 - Other Generation Plant	DeSoto Solar Energy Center	34300	3.30%	150,719,261.61	150,719,261.61
	06 - Transmission Plant - Electric		35200	2.50%	2,715.43	2,715.43
	06 - Transmission Plant - Electric		35300	2.80%	367,956.45	367,956.45
	06 - Transmission Plant - Electric		35500	3.60%	407,620.78	407,620.78
	06 - Transmission Plant - Electric		35600	3.20%	177,168.47	177,168.47
	06 - Transmission Plant - Electric		36200	2.80%	46,014.03	46,014.03
37 - DeSoto Solar Energy Center Total					**151,720,736.77**	**151,720,736.77**
38 - Spacecoast Solar Energy Center						
	05 - Other Generation Plant	Spacecoast Solar Energy Center	34300	3.30%	0.00	78,906,967.19
38 - Spacecoast Solar Energy Center Total					**0.00**	**78,906,967.19**
39 - Martin Solar Energy Center						
	05 - Other Generation Plant	Martin Solar Energy Center	34300	3.30%	0.00	426,282,514.17
	05 - Other Generation Plant	Martin U8	34300	5.50%	350,000.00	350,000.00
	06 - Transmission Plant - Electric		35600	3.20%	956,266.12	956,266.12
39 - Martin Solar Energy Center Total					**1,306,266.12**	**427,588,780.29**
41 - Manatee Heaters						
	02 - Steam Generation Plant	Cape Canaveral Comm	31400	0.70%	0.00	4,680,000.00
	02 - Steam Generation Plant	Riviera Comm	31400	0.60%	4,688,928.00	4,688,928.00
41 - Manatee Heaters Total					**4,688,928.00**	**9,368,928.00**
42 - Turkey Point Cooling Canal Monitoring						
	03 - Nuclear Generation Plant	Turkey Pt Comm	32100	1.10%	0.00	2,600,000.00
42 - Turkey Point Cooling Canal Monitoring Total					**0.00**	**2,600,000.00**
Grand Total					**460,069,078.16**	**1,143,145,091.94**

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 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. 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, 2009 to December 31, 2009)
The monthly fees for 2008 emissions at Scherer have been paid and continue to be paid in 2009. 2008 air operating permit fees for the Florida facilities were calculated in January 2009 utilizing 2008 operating information. They were paid to the FDEP in February, 2009.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
O&M project expenditures are estimated to be $1,007,915 or 51.5% lower than originally projected, primarily due to Cape Canaveral, Riviera, Cutler, Port Everglades 1 and 2, and Sanford 3 being placed in reserve status, which will reduce emission totals for 2009. Reserve status is based on current system demand and operating needs and is subject to change at any time.

Project Progress Summary:
The monthly fees for 2008 emissions at Scherer have been paid and continue to be paid in 2009. 2008 air operating permit fees for the Florida facilities were calculated in January 2009 utilizing 2008 operating information. They were paid to the FDEP in February, 2009.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project expenditures for the period January 2010 through December 2010 are expected to be $1,246,419.

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 is an ongoing activity which follow the Title IV CEMS Quality Assurance Program Manual.

Project Accomplishments:
(January 1, 2009 to June 1, 2009)
Operation and maintenance of the CEMS continue to be performed according to requirements of the Title IV CEM Quality Assurance Program Manual, 40 CFR Parts 60 & 75 regulations and all applicable FAC, as well as local requirements. Relative Accuracy Tests and Linearity Tests continue to be performed as scheduled for quality assurance and as needed for diagnostic or recertification requirements. QA/QC maintenance continues to be performed on the analyzers to meet reliability and availability requirements. CEMS required parts continue to be purchased as needed for repairs and/or preventative maintenance. Calibration span gases continue to be purchased as needed to meet required daily and QA calibrations. 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 proper functionality as well as the integrity of the CEMS data. Maintenance of the software also ensures compliance with current or changes made by the EPA, State and Local Agencies. Training on the Operation and Maintenance of the system, as well as rule/regulation changes continue as needed.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
Project expenditures are estimated to be $38,121 or 3.8% lower than originally projected.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
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, 2010 to December 31, 2010)
Estimated project expenditures for the period January 2010 through December 2010 are expected to be $1,145,571.

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.

PFL Tanks 2 & 3 (with the capacities 80,000 & 150,000 BBLS), PMT Units 1 &2 metering Tanks (capacity each 24,000 BBLS), PMT Light Oil Start up Tank (capacity 2,000 BBLS), TMR Light Oil Boiler Fuel Tank (capacity 5,000 BBLS), and TMT Light Oil Heater Fuel Tank (capacity 5,000 BBLS) were due for API in-service inspection in February, 2009. Inspection of all these tanks plus PMR light Oil Tanks 1/A 7 1/B (capacity each 47,600 BBLS) which were due on May and July 2009 were performed by TEAM (Tank Engineering and Management Consultant, Inc.), in February, May, & June 2009. No discrepancies were reported and all fuel storage tanks appear to be suitable for continued services. However PMT Unit 1 Metering Tank was reported with corroded roof which is budgeted for 2010 for roof replacement. The next due dates for external inspection was determined by API certified inspector after 5 years. PCC Unit 2 Metering Tank (capacity 12,000 BBLS), PCC Tank #2 (capacity 268,000 BBLS), PMR Units 1 &2 Metering tanks (capacity each 24,000 BBLS), PMR Tanks 1371/A & 1371/B (capacity 500,000 BBLS), PMR Light Oil Start Up Tank (capacity 2,000 BBLS), PSN Unit 3 A & B Day Tanks (capacity each 6,000 BBLS), PSN Tank A (capacity 268,000 BBLS), TCC Tank 1 (capacity 265,000 BBLS), TMR tanks 1271/A & 1271/B (capacity 500,000 BBLS), and TMR Purge Tank 1272 (capacity 110,000 BBLS) are due for API in-service inspection later this year and are already scheduled for inspection.

Project Accomplishments:
(January 1, 2009 to December 31, 2009)
Work continued on miscellaneous maintenance of above ground fuel storage tanks and piping systems. All required API 653 external inspections will be completed for this year and all 2009 tank registration fees have been paid. PPE Tanks 903 & 904, TPE Tanks 800, 801, 504, & 806, PFL Tank #5 and associated piping and pipe-supports have been painted and repairs on the stairs of PFL tank #3 and touch up painting on PFL Tanks # 2 & 3 are in progress. All the bulk L/O piping associated to TPE Tanks 901 & 902 and the related pump pits were painted and corroded pipe-supports were repaired and painted. TPE tank 901 (entire roof 7 touchups of the shell) and PTF Units 1 & 2 will be completely painted later this year. Per F.A.C. Chapter 62-761.500(1) (b) exterior portions of above ground tanks and above ground integral piping, excluding double-wall systems, shall be coated or otherwise protected from external corrosion.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
O&M project expenditures are estimated to be $323,924 or 30.3% higher than originally projected. The following project activities were identified after the filing of the original 2009 estimates:
1) After initial estimates and purchase orders were issued there was a scope change for Tank 801 located at the Port Everglade Terminal. Per the specification of the purchase order, loose paint was removed by high pressure water blasting. After the water blasting was complete, only a very thin coat of primer was left on the tank and FPL had to apply primer on the entire shell plates as opposed to spot priming which was in the original scope of work.
2) Due to increasing oil spill events, management decided to conduct a condition assessment of the fuel infrastructure system to identify any immediate concerns. The inspection found that the light oil piping and pipe supports of Port Everglades Plant Tanks 903 and 904 were corroded and needed to be repaired and replaced.
3) Tanks 2, 3, and 5 at the Fort Lauderdale Plant were developing severe corrosion. FPL decided to re-paint the tanks in an effort to effectively maintain the coating of the tanks, which prevents premature deterioration of the tank.
4) A painting project scheduled for 2010 for the Port Everglades Terminal Tank 901 was implemented in 2009 to interrupt on-going corrosion of the tank. This was also done to effectively maintain the coating and prevent premature deterioration.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
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. PFL Tank #3 & TPE Tank 801 corroded stairs were repaired. TPE Tanks 901 & 902 dike liners were repaired as needed.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures for the period January 2010 through December 2010 are expected to be $2,051,046.

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, 2009 to December 31, 2009)
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 new team members. Finally, a boat lift was installed at the Cape Canaveral Plant, and in the third quarter a boat lift will be installed at the Fort Myers Plant. This allows for a quicker response time in the event of a spill.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
No variance estimated for this project.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
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 also performs maintenance (required) on the oil spill equipment at all of the power plants as well as performs an annual (required) equipment deployment drill at these facilities. We will be installing boat lifts at the Fort Myers Plant during the third quarter.

FPL has retained a spill management company to assist in corporate-level responses, improved/enhanced the Fleet's ability to mobilize spill equipment (specifically boats), and continues to certify all oil spill response members in the NIMS mandated Incident Command System (ICS).

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures for the period January 2010 through December 2010 are expected to be $197,600.

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 (RFAs) 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 (SWMUs). 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, 2009 to December 31, 2009)
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 oversight. The EPA withdrew the 2007 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 and submitted to FDEP. A Facility Evaluation took place in the third quarter of 2007 and the site received the final report from the Department granting No Further Action.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
O&M project expenditures are estimated to be $36,258 or 72.5% lower than originally projected. The RCRA project was established in anticipation of receiving an FDEP Final Report in December 2008. Due to internal resource limitations at FDEP, as of June 20, 2009 a report has yet to be issued. No further actions are anticipated for the remainder of 2009.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
The Power Generation Division completed all work associated with RCRA at the Manatee and Turkey Point Fossil sites in 2007. The FDEP has granted final No Further Action for the Manatee Plant. The FDEP is finalizing the draft report approved by FPL for the Turkey Point Plant. This draft report recommended No Further Action for the site. No additional work was recommended by the Department in order to reach a No Further Action agreement. No other activities are scheduled for 2009. The final report from the Department granting No Further Action for the Turkey Point Plant is expected to be received shortly.

Project Projection:
(January 1, 2010 to December 31, 2010)
Projections for 2010 are $100,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **NPDES Permit Fees - O & M**
Project No. 14

Project Description:
In compliance with State of Florida Rule 62-4.052, 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, 2009 to December 31, 2009)
The NPDES permit fees were paid to FDEP for Power Generation Operating Plants.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
The variance is expected to be $500 or 0.4% lower than originally projected.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
The NPDES annual regulatory program and surveillance fees were paid to FDEP for Power Generation Operating Plants.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project expenditures for the annual regulatory program and surveillance fees for the period January 2010 through December 2010 are expected to be $138,900. The regulatory program and surveillance fees will be due in January, 2010.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Disposal of Noncontainerized Liquid Waste - O&M
Project 17a

Project Description:
FPL manages ash from heavy oil fired power plants using a wet ash system. Ash from the dust collector and economizer is sluiced to surface ash basins. The ash sludge is then pH adjusted to precipitate metals. In order to comply with Florida Administrative Code 62-701.300 (10), the ash is then de-watered using a plate/frame filter-press in order to dispose of it in a Class I landfill or ship by railcar to a processing facility for beneficial reuse.

Project Accomplishments:
(January 1, 2009 to December 31, 2009)
Ash work has been completed at Riviera, Martin, Manatee, and Port Everglades. Sanford will be complete in July and August, concluding the ash basin cleanouts for 2009.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
The variance is expected to be $29,956 or 9.3% lower than originally expected.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
This is an ongoing project. The frequency of basin clean out is a function of basin capacity and rate of sludge/ash generation.

Project Projections:
(January 1, 2010 to December 31, 2010)
Project fiscal expenditures for the period January 2010 through December 2010 are now estimated at $240,000.

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. This project includes the prevention and removal of pollutant discharges at FPL substations and will prevent further environmental degradation. Additionally, remediation activities are ongoing at 7 substations located in Miami-Dade County and the encapsulation of lead-based paint on certain substation equipment which adheres to county regulations as defined in municipal codes.

Project Accomplishments:
(January 1, 2009 to December 31, 2009)
Our leak/regasketing work of oil-filled equipment has significantly increased from last year. We have completed the development of a complex data base to provide greater efficiency in managing this work. Thus far, we have repaired leaks and/or regasketed 158 transformers due to our data base tracking and the increasing support from the field. It is anticipated that this work will decrease in the summer months due to the difficulty in obtaining equipment clearances. However, this work typically increases toward the end of the year once the cooler weather arrives. In addition, our oil absorbent pad change-out program, which prevents oil from impacting the environment from leaking equipment, has dramatically increased. As a result of this program, the number of minor oil clean-up work at substations has started to decrease. Equipment encapsulation work is scheduled for two units in 2009. Environmental remediation work continues at 7 substations located in Miami-Dade County due to various degrees of lead and arsenic contamination.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)

19a O&M project expenditures are estimated to be $196,392 or 7.3% higher than previously projected. This variance is primarily due to an increase in field support that resulted in an increase in leak repair/regasketing work conducted this year. In addition, to prevent impacts to the environment from leaking equipment, and to decrease soil remediation costs resulting from such impacts, FPL has aggressively increased its oil pad absorbent change-out program.

19b The variance in project expenditures is estimated to be $32,112 or 4.4% lower than expected.

19c No expenditures are required.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
The equipment leak repair and regasketing work continues. We have completed the development of a complex data base to provide greater efficiency in managing this work. We anticipate the number of minor cleanup work at substations will be minimal toward the end of this year. The arsenic and lead in soils and/or groundwater continues to be addressed at 7 substations located in Miami-Dade County. A pump and treat system to remediate arsenic-contaminated groundwater at the University Substation is currently being evaluated. The closure of 2 of the substations is anticipated this year.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures for the period January 2010 through December 2010 are expected to be:

19a $2,496,000
19b $755,000
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, 2009 to December 31, 2009)
The project is on hold due to the Pt. Everglades ESP Project.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
Project expenditures are estimated to be $0.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
The project is on hold due to the Pt. Everglades ESP Project.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures for the period January 2010 through December 2010 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, 2009 to December 31, 2009)
Installation of a new turtle new was completed in 2009. Project is complete.

Project Fiscal Expenditures:
(January 1, 2009– December 31, 2009)
Project expenditures are estimated to be $0.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
The new net was installed and the old net will serve as a backup.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures for the period January 2010 through December 2010 are $0.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Pipeline Integrity Management (PIM) – O&M
Project No. 22

Project Description:
FPL is required to develop a written pipeline integrity management program for its hazardous liquid / gas 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, 2009 to December 31, 2009)
The on going integrity assessments are undertaken for the corporate liquid/gas pipelines along with associated evaluations and appropriate countermeasures. In-line Inspection of TMR dual service (gas/oil) pipeline which was originally scheduled on December, 2008 was postponed to April, 2009 due to conflict with the Martin Plant (PMR) operations. PII/GE conducted geometry and MFL high resolution MFL tool on April, 2009. No major issue was identified as a result of this inspection.
Following the ILI inspections confirmatory dig(s) should be performed to validate the accuracy of the data obtained by inspection tools. Confirmatory dig(s) will be accomplished later this year.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
O&M project expenditures are estimated to be $210,628 or 526.6% higher than originally projected. The variance is primarily due to the deferral to April 2009 of the In-Line Inspection (Smart Pigging) activities scheduled for the Martin Plant in December 2008. Due to lower than projected residual oil use to meet FPL system dispatch generation needs, required available space within storage tanks was insufficient for recovery of oil during planned use of Pipeline Inspection Gauge (PIG) work.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
This is an ongoing project. Martin 18" dual (gas/oil) pipeline was inspected by high resolution MFL tool this year. Two assessment and evaluation digs, will be conducted following the in-line inspection (smart pig) 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 maybe even more as necessary confirmatory digs and conducting the direct assessment and inspection on the location of the detected anomalies). UTMs and magnetic particle testing is a part of these direct assessment.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures for the period January 2010 through December 2010 are expected to be $405,000.

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, 2009 to December 31, 2009)
FPL is continually working on the Facility Response Plans (FRP), which contain the SPCC plans of which FPL has 625. These plans are constantly being revised due to oil-filled equipment being relocated or removed, or new oil-filled equipment being installed, at substations. In addition, SPCC Plans are being developed and maintained for new substations due to the construction of power generation expansion projects. Oil diversionary structures are being repaired at certain substations as a result of substation maintenance work. We are evaluating if more efficient diversionary materials, other than concrete curbing, can be used as an alternative. Also, SPCC-required quarterly inspections of all substations are constantly being performed. FPL continues to work on planning and conceptual engineering for additional facility upgrades that have been identified for implementation in 2010. The new EPA due date for completion of the plans and upgrades is November 10, 2010.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
O&M project expenditures are estimated to be $176,252 or 25.6% higher than originally projected. This variance is primarily due to revisions made to the SPCC plans, which are required when oil-filled equipment is either relocated or removed or when new oil-filled equipment is installed at substations. In addition, FPL has increased substation inspections to provide more frequent information to better manage the oil pad absorbent change-out program stated in Project No. 19a. Finally, additional upgrade projects listed below were identified through the Fleet Request System requiring engineering and planning work in 2009.

- Port Everglades Units 1&2 - Add impervious bottoms to existing oil trap, and increase metering tank areas secondary containments.
- Port Everglades Units 3&4 - Add oil/water separator to replace two existing oil traps, and increase metering tank areas secondary containments.
- Port Everglades and Fort Lauderdale - Modify drainage at main transformers at the gas turbine power parks.
- Port Everglades Terminal - Repair secondary containment berm around the fuel oil tanks.
- Fort Myers - Add secondary containment at 12 gas turbines.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
FPL is continually working on the Facility Response Plans (FRP), which contain the SPCC plans. In addition, FPL continues to work on planning and conceptual engineering for additional facility upgrades that have been identified for implementation in 2010. The new EPA due date for completion of the plans and upgrades is November 10, 2010.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Additionally due to the large amount of quarterly substation inspections reports that are being generated, FPL has completed the development of a complex data base to manage all the inspection information. This data base has provided an efficient method of gathering information to identify compliance gaps that need to be addressed.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project expenditures for the period January 2010 through December 2010 are expected to be $2,226,581.

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 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, and 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, 2009 to December 31, 2009)
The units continue to operate reliably and minor tuning of the process continues. The systems have achieved significant NOx emission reductions. The PMT Reburn O&M ECRC dollars cover all on-going burner and equipment maintenance costs associated with the project.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
Estimated project expenditures for the period January 2009 through December 2009 are expected to be $500,000. No variance estimated.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
Unit 1 & Unit 2 are operating as referenced above. Final report has been presented to DEP. FDEP has accepted FPL's proposed limits and the project is now complete. Project expenditures will be based on runtime and available maintenance time.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project expenditures for the period January 2010 through December 2010 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 (O3), sulfur dioxide (SO2), 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, expired in 2003. The renewal permit issued January 1, 2004 is now expiring December 31, 2008. A renewal permit application has been submitted and is pending DEP review. The DEP's Title V permit for FPL Port Everglades plant requires FPL to install and maintain 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, 2009 to December 31, 2009)
The ESP engineering design for Units 1–4 was completed in 2004. All four Units' ESPs were completed between 2005 and 2007 and are operational (O&M activities started in April 2005 for this project).

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
O&M project expenditures are estimated to be $226,484 or 9.9% lower than originally projected, primarily due to fewer running hours as a result of lower demand for generation. Also, lower natural gas prices resulted in more natural gas and less oil being burned than originally expected at the plant. Consequently, less ash was created with an associated reduction in use of the chemical injection system resulting in lower costs of chemicals and ash disposal.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
Construction on all four electrostatic precipitators was completed and all four units ESPS are operational.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project expenditures for the period January 2010 through December 2010 are expected to be $2,344,807.

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, 2009 to December 31, 2009)
There were no activities in 2009.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
Project expenditures are for 2009 are $0.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
Initial review of the scope of work has been completed.

Project Projections:
(January 1, 2010 to December 31, 2010)
There are no activities planned for 2010.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

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

Project Description:
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 Plant. 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 Plant 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 LQWS project at Sanford Plant is currently operational.

Project Accomplishments:
(January 1, 2009 to December 31, 2009)
The project at the Sanford Plant is currently operational.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
O&M project expenditures are estimated to be $46,192 or 17.9% higher than originally projected, primarily due to a process change made to monitoring and reporting LQWS usage in third quarter 2008, which has improved the way FPL measures and reports LQWS. Previously, LQWS calculations were based on a 90%/10% distribution of water consumed between Sanford Units 4 and 5 and Sanford Unit 3 respectively. Due to the minimal usage of Unit 3 and because most water, if not all, is being consumed by Units 4 and 5, FPL made the distribution according to operational hours. The new calculation is based on gallons consumed/used and is tracked electronically.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
The project at the Sanford Plant is currently operational.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures for the period January 2010 through December 2010 are expected to be $302,436 for the Sanford Plant.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **CWA 316(b) Phase II Rule**
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, Lauderdale, Port Everglades, Riviera, Sanford, Martin, Manatee and St. Lucie Power Plants.

Project Accomplishments:
(January 1, 2009 to December 31, 2009)
Until the 316(b) rule is reissued by the United States Environmental Protection Agency (USEPA), the Florida Department of Environmental Protection (FDEP) requires the submittal of the Impingement Mortality and Entrainment Characterization Studies (IMECS) as well as the required supporting information as part of each plant's NPDES permit renewal. The above mentioned documents were previously submitted to the FDEP for the Fort Lauderdale, Port Everglades, Riviera, and Fort Myers Plants. In addition, the IMECS has been completed for the Cape Canaveral Plant and the IMECS for the Cutler Plant has been drafted. The Clean Water Act 316(b) supporting information documents to be submitted concurrently with the NPDES permit renewals for the Cape Canaveral and Cutler Plants will be finalized later in 2009.

Results from the biological studies at each plant were used to assess the effectiveness of existing technologies and operational measures in an effort to mitigate impingement mortality and entrainment. These results were also utilized to refine each plant's strategy for compliance with the 316(b) rule. Finally, the Draft Technology Assessment Reports have been completed for the Fort Lauderdale, Port Everglades, and Riviera Plants. The draft reports for the Cape Canaveral, Fort Myers, and Cutler Plants will be finalized later in 2009.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
O&M project expenditures are estimated to be $837,121 or 137.9% lower than originally projected, primarily due to the following issues:
An adjustment of $188,000 was made per Order No. PSC-04-0987-PAA-EI issued on October 11, 2004, for the netting of environmentally related study costs in base rates from actual costs incurred for 2008.

The EPA has initiated new Section 316(b) rulemaking consistent with the ruling of the U.S. Court of Appeals for the Second Circuit and a new rule has been delayed following the U.S. Supreme Court decision in early 2009. Therefore, the planned work under the EPA Clean Water Act 316(b) section has been delayed as a result of ongoing litigation concerning the appropriateness and application of the rule and EPA's efforts to rewrite the rule. Until the additional rulemaking by the EPA is complete, the 316(b) project will be on standby and work will resume following promulgation of the revised rule.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
The IMECS and required supporting information documents have been previously submitted to the FDEP for the Fort Lauderdale, Port Everglades, Riviera and Fort Myers Plants. The IMECS has been completed for the Cape Canaveral Plant and the IMECS for the Cutler Plant has been drafted. The supporting information documents to be submitted concurrently with the IMECS portion of the Cape Canaveral and Cutler Plants NPDES permit renewals shall be finalized later in 2009.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures for the period January 2010 through December 2010 are expected to be $285,000.

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, 2009 to December 31, 2009)
The SCR systems are operational on both Manatee Unit 3 and Martin Unit 8.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
O&M project expenditures are estimated to be $56,991 or 16.3% lower than originally projected primarily due to lower than projected generation from Manatee Unit 3 and Martin Unit 8 as a result of lower than originally projected system demand. Also, the direct correlation of ammonia prices to natural gas prices, due to the use of natural gas in ammonia, reduced the costs for purchase of anhydrous ammonia to lower levels than originally projected.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
The SCR systems are operating reliably on both Manatee Unit 3 and Martin Unit 8.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures for the period January 2010 through December 2010 are expected to be $350,000 for PMR/PMT.

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, 2009 to December 31, 2009)
Continue with river monitoring, calibration, maintenance and data collection. Vegetative mapping, aerial photography and mapping were conducted in October 2007. Additional studies are being conducted during summer due to drought conditions and use of Emergency Diversion Schedule. Interpretive Report Completed in July of 2009, along with salinity report required due to use of Emergency Diversion Curves in 2009.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
O&M project expenditures are estimated to be $767 or 1.9% higher than originally projected.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
This is an ongoing project.

Project Projections:
(January 1, 2010 to December 31, 2010)
Project estimates for January 2010 through December 2010 are expected to be $34,000.

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, the costs for the operation of SCR's under construction on SJRPP Units 1 and 2, costs for the operation of the Scrubber and SCR being installed on Scherer Unit 4, and the installation of CEMS 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 are likely to change as a result of contractual guarantees related to necessary overhaul schedules, component and materials costs and labor estimates.

Project Accomplishments:
(January 1, 2009 to December 31, 2009)
Manatee has completed the L0 & L1 Inspections and the A and B Boiler Feed Pump Recirculation Regulator Inspections of their O&M projects during the Unit 2 Spring Outage. The Throttle Valve Plugs were removed and sent to a supplier for refurbishment, Solid Particle Erosion coating, and return shipment to the Martin plant. SJRPP U2 SCR was placed in-service in 3/2009. Construction was completed on U1 in May 2009. Currently, U1 is conducting performance and acceptance testing.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
O&M project expenditures are estimated to be $487,919 or 30.3% lower than originally projected. The following project activities were identified after the filing of the original 2009 estimates:
1) The planned outage at Martin 2, which impacts the 800MW Unit Cycling Project, changed from September to December 2009 thereby reducing planned activities for 2009.
2) At St. Johns River Power Park (SJRPP) Unit 2, lower than expected costs for purchase of anhydrous ammonia and additional under-runs occurred due to the in-service date of Unit 2 being postponed from its original in-service date of January 2009 to March 2009.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
The Manatee Throttle Valve Plugs have been sent for refurbishment and Solid Particle Erosion coating and will be returned to Martin for use during the Unit 2 outage. Pre-work for the Manatee Water Treatment Plant is underway in support of an April 2010 on-line date. The new concrete pad portion of this scope met the requirements for capitalization. Additional required testing will occur in a five year cycle per the rule FPL projects operation and maintenance costs for the U1 SCR on SJRPP to begin in the second quarter of 2009 as construction was completed and the controls are put into service. O&M costs for U2 is scheduled to commence in the 3rd quarter 2009. O&M costs associated with the Scrubber and SCR's at plant Scherer will occur starting in 2012 when the construction is completed.

Project Projections:
(January 1, 2010 to December 31, 2010)
Total estimated 2010 O&M costs are $3,134,000.

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, 2009 to December 31, 2009)

- 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, 2009 to December 31, 2009)
Project expenditures are estimated to be $0.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
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 5/3/2007. FPL and FDEP successfully negotiated the terms of the Draft BART permit for PTF Units 1 and 2. The permit was final on April 14, 2009. The terms of the permit will become effective in 2013.

Project Projections:
(January 1, 2010 to December 31, 2010)
Project estimates for Jan 2010 through December 2010 are expected to be zero. No additional modeling expenses are anticipated for 2009. PGD may incur engineering expenses regarding the installation of new cyclone separators for PTF 1&2 BART Determination. This will be determined at a later date.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: CAMR Compliance– O&M
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, 2009 to December 31, 2009)
Construction has been completed on baghouse pilings and foundations. Construction is currently in progress for structural steel, compartments and plenums, activated carbon Sorbant handling equipment, and inlet and outlet ductwork.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
No variance anticipated with projected O&M expenses in 2009 for CAMR compliance project.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
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 Georgia Multi-Pollutant Rule. Installation of controls requires a specific sequence for the construction of the controls and material handling systems. The baghouse on Unit 4 is projected with an in-service date of June 2010. O&M costs associated with the CAMR Compliance project include expenses associated with purchase of Sorbant used for flue gas mercury removal and disposal of spent Sorbant.

Project Projections:
(January 1, 2010 - December 31, 2010)
Estimated project fiscal expenditures (depreciation and return) for the period January 2010 through December 2010 are projected to be $3,304,000 for Sorbant purchase and disposal.

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 1, 2009 to December 31, 2009)
No cleaning of the intake pipes was performed during 2009. Cleaning of the intake pipes will resume in 2010 and is now expected to be completed in 2012.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
O&M project expenditures $1,323,040 or 73.5% lower than originally projected, due to the deferral to 2010 of pipe cleaning activities. Since these activities must be completed during a refueling outage, and unfavorable weather and ocean conditions have historically been an issue in completing planned activities, FPL has deferred these activities until the next refueling outage which is planned for the spring of 2010.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
Cleaning of the 12' south intake pipe and velocity caps will resume in the St. Lucie outage occurring in Spring 2010. Anticipated completion of the project is in 2012.

Project Projections:
(January 1, 2010 to December 31, 2010)
Project estimates for January 2010 through December 2010 are expected to be $1,351,983.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Martin Plant Water System – O&M**
Project No. 35

Project Description:
The Martin Drinking Water System is required to comply with the requirements the Florida Department of Environmental regulations rules for drinking water systems. The Florida Department of Environmental Protection (FDEP) determined the system must be brought into compliance with newly imposed drinking water rules for TTHM (trihalomethanes) and HAA5 (Haleo Acetic Acid). The upgrades to the potable water system will cause FPL to incur Capital costs for major component upgrades to the system in order to comply with the new requirements. These include Nano filtration, air stripping, carbon and multimedia filtration. The operation of the Potable system will cause FPL to incur O&M costs for certain products that are consumed during the water treatment process. These include carbon and multimedia bed media and nano filtration media.

Project Accomplishments:
(January 1, 2009 to December 31, 2009)
The project is implemented. The agency has inspected and approved system startup and testing. The system will continue to run throughout 2009. O & M dollars are expected in October 2009.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
Project expenditures are estimated to be $17,000. No variance estimated.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
No O&M expenditures to date, 2009 expenditures expected October 2009.

Project Projections:
(January 1, 2010 to December 31, 2010)
The 2010 estimate remains at the current estimate of $17,000 for projected replacement used media beds.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Low Level Radioactive Waste – O&M**
Project No. 36

Project Description: The Barnwell, South Carolina radioactive waste disposal facility is the only site of its kind presently available to FPL for disposal of Low Level Waste (LLW) such as radioactive spent resins, filters, activated metals, and other highly contaminated materials. The Barnwell facility ceased accepting LLW from FPL June 30th, 2008. This project will construct a LLW storage facility for class B and C radioactive waste at the St. Lucie Plant (PSL). Turkey Point (PTN) will be implementing a similar project; however the PTN project will start later than the PSL project since PTN has some limited existing LLW storage capacity. Where practical, this project will be implemented as part of a fleet approach. The objective at PSL and PTN is to ensure construction of a LLW storage facility with sufficient capacity to store all LLW B and C class waste generated at each plant site over a 5 year period. This will allow continued uninterrupted operation of the PSL and PTN nuclear units until an alternate solution becomes available. The LLW on site storage facilities at PSL and PTN will also provide a "buffer" storage capacity for LLW even if an alternate solution becomes feasible, should the alternate solution be delayed or interrupted at a later date.

Project Accomplishments:
(January 1, 2009 to December 31, 2009)
Field work has been performed at PSL and PTN to determine the potential location for each site's LLW storage facility. Project planning is going forward. Conceptual designs for LLW storage facilities are being developed and evaluated by Engineering and Nuclear Projects. The Nuclear Projects Department has worked with each site's Radiation Protection Department to develop several measures to ensure LLW storage capability exists at PSL and PTN until the LLW storage facilities can be completed at PSL and PTN. For PSL this consists of the purchase of a LS3 portable Ground Shield, two rain covers and additional insertable cylindrical shielding for existing concrete Ground Shields to meet RP surface dose rate restrictions for the storage casks. For Turkey Point the interim measures being considered to ensure LLW storage capacity is available until a facility is constructed includes purchasing new rigging to allow safely moving existing ground shields so that they can be used to store LLW.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
O&M project expenditures are estimated to be 1,000,887 or 100.1% lower than originally projected. Original project estimates, which were determined during the initial development of the project schedule, plan and conceptual design of the facility, were classified as O&M. After review of internal procedures and completion of several cost analyses and estimates, FPL determined the construction of a Low Level Waste Interim Storage Facility at Port St. Lucie and Turkey Point qualifies as a capital project.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
The project for PSL and PTN is on schedule. Initial scoping work is progressing and conceptual designs for LLW storage facilities are under development and evaluation to choose the optimal solution for each site. Interim measures to provide limited LLW storage capacity have been implemented to allow LLW storage until LLW storage facilities are completed at the sites. The PTN facility is still in the early stages of scope development due to the fact that the need for a LLW storage facility is not as urgent as PSL.

Project Projections:
(January 1, 2010 to December 31, 2010)
Project estimates for January 2010 through December 2010 are expected to be zero.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: DeSoto Next Generation Solar Energy Center – O&M
Project No. 37

Project Description:
The DeSoto Next Generation Solar Energy Center ("DeSoto Solar") project is a zero greenhouse gas emitting renewable generation project which on August 4, 2008, the Commission found in Order Number PSC-08-0491-PAA-EI, to be eligible for recovery through the ECRC pursuant to House Bill 7135. The DeSoto Solar project is a 25 MW solar photovoltaic generating facility which will convert sunlight directly into electric power. The facility will utilize a tracking array that is designed to follow the sun as it traverses through the sky. In addition to the tracking array this facility will utilize cutting edge solar panel technology. The project will involve the installation of the solar PV panels and tracking system and electrical equipment necessary to convert the power from direct current to alternating current and to connect the system to the FPL grid.

Project Accomplishments:
(January 1, 2009 to December 31, 2009)
As of June 29, 2009, 99% of the 90,504 Solar PV Panels have been installed and 100% of the Trackers Motors have been installed. Approximately 40% of the wiring has been completed and system testing is in progress. Initial power operational testing is scheduled for September and full commercial operation (25 MW) is scheduled for October 31, 2009.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
O&M project expenditures are estimated to be $230,375 or 49.3% lower than originally projected. The variance is primarily due to a change in the estimated final completion date of the project from July 2009 to October 2009. Estimated O&M prior to the revised commercial in-service date of the plant were significantly reduced.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
The project originally planned on turning over phases of the solar array from construction to commercial operation. Due to schedule delays associated with the main power control room, testing and commissioning will be compressed to the last several months with some overlap between final construction activities and commissioning. The plant will not be turned over to operations in phases due to the complexity of testing and safety concerns. The project had an early expected completion date (at least in phases) for July 2009 but has been moved back to original completion date of October 31, 2009.

Project Projections:
(January 1, 2010 to December 31, 2010)
The 2010 estimate remains at the current estimate of $1,260,080.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Space Coast Next Generation Solar Energy Center – O&M
Project No. 38

Project Description:
The Space Coast Next Generation Solar Energy Center ("Space Coast Solar") project is a zero greenhouse gas emitting renewable generation project which on August 4, 2008, the Commission found in Order Number PSC-08-0491-PAA-EI, to be eligible for recovery through the ECRC pursuant to House Bill 7135. The Space Coast Solar project is a 10 MW solar photovoltaic (PV) generating facility which will convert sunlight directly into electric power. The facility will utilize a fixed PV array oriented to capture the maximum amount of electricity from the sun over the entire year. The project will involve the installation of the solar PV panels and support structures and electrical equipment necessary to convert the power from direct current to alternating current and to connect the system to the FPL grid.

The Space Coast project also includes building a 900 KW sola PV facility at the Kennedy Space Center (KSC) industrial area. This 900 KW solar site will be built and operated and maintained by FPL as compensation for the lease of the land for the Space Coast Solar Site which is located on KSC property.

Project Accomplishments:
(January 1, 2009 to December 31, 2009)
The 900 KSC Solar Site is approximately 50% complete with a scheduled commercial operation date in September, 2009. Ground clearing has begun at the Space Coast Solar Site beginning June 1, 2009 and site mobilization is in progress. Commercial operation is scheduled for June, 2010.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
O&M project expenditures are estimated to be $10,240 or 51.2% higher than originally projected. Original O&M cost estimates were based on the construction of a 500 KW site as compared to the current plan for a 900 KW site.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
Progress at the KSC Solar Site has been good and schedule has moved up approximately one month. As such, O&M costs are expected to be higher, especially in area of vegetation management.

Project Projections:
(January 1, 2010 to December 31, 2010)
The 2010 estimate remains at the current estimate of $511,720.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Martin Next Generation Solar Energy Center - O&M**
Project No. 39

Project Description:
The Martin Next Generation Solar Energy Center ("Martin Solar") project is a zero greenhouse gas emitting renewable generation project which on August 4, 2008, the Commission found in Order Number PSC-08-0491-PAA-EI, to be eligible for recovery through the ECRC pursuant to House Bill 7135. The Martin Solar project is a 75 MW solar thermal steam generating facility which will be integrated into the existing steam cycle for the Martin Unit 8 natural gas-fired combined cycle power plant. The steam to be supplied by Martin Solar will be used to supplement the steam currently generated by the heat recovery steam generators. The project will involve the installation of parabolic trough solar collectors that concentrate solar radiation. The collectors will track the sun to maintain the optimum angle to collect solar radiation. The collectors will concentrate the sun's energy on heat collection elements located in the focal line of the parabolic reflectors. These heat collection elements contain a heat transfer fluid which is heated by the concentrated solar radiation to approximately 750 degrees Fahrenheit. The heat transfer fluid is then circulated to heat exchangers that will produce up to 75 MW of steam that will be routed to the existing natural gas-fired combined cycle Unit 8 heat recovery steam generators.

Project Accomplishments:
(January 1, 2009 to December 31, 2009)
Current estimated in-service date of this project to be December, 2010. No O&M cost associated with this project until 2011

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
There is no variance expected for this project.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
Current estimated in-service date of this project to be December, 2010. No O&M cost associated with this project until 2011.

Project Projections:
(January 1, 2010 to December 31, 2010)
The current 2010 estimate remains at zero.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Greenhouse Gas Reduction Program - O & M
Project No. 40

Project Description:
The purpose of FPL's proposed Electric Utility Greenhouse Gas Reduction Program is to implement both the reporting and emission reduction requirements established under Chapter 403 of the Florida Statutes that set a maximum allowable emission level of greenhouse gasses in the state of Florida. During the initial implementation of the program electric utilities, major emitters of GHG's, are required to participate in The Climate Registry providing historical and current greenhouse gas emission data to establish the baseline emissions and targets for the required compliance reductions to meet the 2017, 2025 and 2050 deadlines. In subsequent years utilities will be required to engage third party verification of their reported inventory. To comply with future GHG Cap and Trade programs FPL will need to recover GHG emission allowance costs through this project. To achieve the future reduction goals established by the executive order FPL anticipates that in additional reductions in its GHG emissions will be required beyond the currently planned fossil unit conversions, nuclear uprates, and the addition of new nuclear generating units. The additional reductions will likely require a combination of the implementation of carbon sequestration and storage technology and the use of verified carbon offset projects.

Project Accomplishments:
(January 1, 2009 to December 31, 2009)
FPL proposes to delay implementation of the Greenhouse Gas Reduction Program originally approved by the Commission, and its associated costs, until either Florida Department of Environmental Protection (FDEP) promulgates a final rule providing guidance to utilities for participation in the Climate Registry or EPA promulgates a final rule requiring the mandatory reporting of GHG's.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
O&M project expenditures are estimated to be $50,000 or 100% lower than originally projected. The variance is primarily due to the delay in the FDEP promulgating a final rule providing guidance to utilities regarding the required date to join The Climate Registry as well as the delay of the EPA proposal for the establishment of a national mandatory greenhouse gas reporting requirement. FPL is proposing to delay implementation of the Greenhouse Gas Reduction Program until either the FDEP promulgates a final rule providing guidance to utilities for participation in The Climate Registry or the EPA promulgates a final rule requiring the mandatory reporting of Greenhouse Gases.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
FPL has not yet joined The Climate Registry or prepared Registry required documentation for reporting historical data. FPL continues in its participation with the FDEP in its rule development workshops and anticipates that a final rule providing detailed requirements later this year or in 2010.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project expenditures for the period January 2010 through December 2010 are expected to be $50,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Manatee Temporary Heating System – O&M**
Project No. 41

Project Description:
Due to the specific and continuing legal requirement for FPL to endeavor to provide a warm water refuge for the endangered manatee at its Riviera (PRV) and Cape Canaveral Plants (PCC), FPL has to factor its unique obligation into otherwise continue routine and normal operation and maintenance considerations and decisions. FPL undertakes to design, engineer, purchase, and install a temporary manatee heating system at both PRV and PCC ("the Project") pursuant to PRV's and PCC's Manatee Protection Plans (MPP), as part of the State Industrial Wastewater Facility Permit Numbers FL0001546, Specific Condition 13, issued on February 16, 1998 and FL0001473, Specific Condition 9, issued on August 10,2005, respectively. In order to comply with the respective MPP's, FPL will pursue installing a temporary manatee heating system endeavoring to avoid potential adverse impacts to manatees congregating at PRV's and PCC's manatee embayment area during the annual period from November 15 to March 31 at PRV and the annual period of October 15 to March 31 at PCC. Due to the prescribed annual period for providing warm water and the time required to design, engineer, purchase, and install the manatee heating system, the Project will begin immediately.

Project Accomplishments:
(January 1, 2009 to December 31, 2009)
Work on this project is expected to begin in the last quarter of 2009.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
This project was not anticipated when original estimates for 2009 were filed in August 29, 2008. O&M expenditures are estimated to be $12,500.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
2009 O&M costs for maintaining the PRV system will be incurred in the final quarter of 2009. Engineering, dredging, and electrical feed costs will be complete by the end of August, 2009. Installation is scheduled to be completed by the end of November, 2009.

Project Projections:
(January 1, 2010 to December 31, 2010)
The 2010 estimate remains at the current estimate of $252,249.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Turkey Point Cooling Canal Monitoring Plan - O & M**
Project No. 42

Project Description:
Pursuant to Conditions IX and X of the Florida Department of Environmental Protection's (FDEP) Final Order Approving Site Certification, filed October 29, 2008, FPL submitted its initial draft of the proposed Cooling Canal Monitoring Plan associated with FPL's Turkey Point Uprate Project to the South Florida Water Management District (SFWMD). This plan requires an assessment of baseline conditions to provide information on the vertical and horizontal extent of the hypersaline groundwater plume and effect of that plume on ground and surface water quality, if any. Comments, concerns and requests for revisions or action items were received from the SFWMD as well as the FDEP. Miami-Dade Department of Environmental Resource Management (DERM) has incorporated into the current draft the proposed monitoring plan, dated July 16, 2009.

The CCM Plan has not yet been finalized or agreed upon by FPL and the agencies and is therefore subject to change based on input from the agencies. FPL expects a revised monitoring plan to be approved by mid September 2009. The objective of FPL's CCM Plan is to implement the Conditions of Certification IX and X, which states that "the Revised Plan shall be designed to be in concurrence with other existing and ongoing monitoring efforts in the area and shall include but not necessarily be limited to surface water, groundwater and water quality monitoring, and ecological monitoring to: delineate the vertical and horizontal extent of the hyper-saline plume that originates from the cooling canal system and to characterize the water quality including salinity and temperature impacts of this plume for the baseline condition; determine the extent and effect of the groundwater plume on surface water quality as a baseline condition; and detect changes in the quantity and quality of surface and groundwater over time due to the cooling canal system associated with the Uprate Project. The Revised Plan shall include installation and monitoring of an appropriate network of wells and surface water stations.

Project Accomplishments:
(January 1, 2009 to December 31, 2009)
FPL is still in negotiation with Florida Department of Environmental Protection, South Florida Water Management District and Miami-Dade Department of Environmental Resource Management in developing the CCM Plan. The deadline has been extended to October 16, 2009. If the plan is approved we anticipate purchasing monitoring equipment in 2009.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
Project expenditures are estimated to be $200,000. This is a new project started in 2009.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
The agencies and FPL have yet to agree on the CCM Plan. FPL is still in negotiations to develop a CCM Plan that will accomplish the intent and comply with of the FDEP Conditions of Certification.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project expenditures for the period January 2010 through December 2010 are expected to be $3,400,000.

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, 2009 to December 31, 2009)
All six units are in service and operational.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
The variance in depreciation and return is $3,250 or 0.4% higher than projected.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
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, 2010 to December 31, 2010)
Estimated project fiscal expenditures (depreciation and return) for the period January 2010 through December 2010 are expected to be $731,911.

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 SO2, NOx and carbon dioxide (CO2) emissions, as well as volumetric flow, heat input, and 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, 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, 2009 to December 31, 2009)
The 2009 Continuous Emission Monitoring System Capital Project necessary to replace the CEMS view nodes at Fort Myers, Sanford and Putnam continue to be scheduled for the later part of 2009.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
The variance for this project is $74,760 or 7.3% lower than originally projected.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
All sites are scheduled for later part of this year and are progressing with timetables to complete on time.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures (depreciation and return) for the period January 2010 through December 2010 are expected to be $909,622.

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 CCEDs 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, 2009 to December 31, 2009)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
The variance in depreciation and return is $2.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
All activities are complete.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures (depreciation and return) for the period January 20010 through December 2010 are expected to be $3,545.

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, 2009 to December 31, 2009)
Installation of new radar level detector on PMT metering tank will be installed in the 4th quarter.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
The variance in depreciation and return is $2,932 or 0.2% higher than projected.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
Installation of new radar level detector on PMT metering tank will be installed in the 4th quarter.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures (depreciation and return) for the period January 2010 through December 2010 are expected to be $1,607,566.

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, 2009 to December 31, 2009)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
The variance in depreciation and return is $0.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
This project is complete.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures (depreciation and return) for the period January 2010 through December 2010 are $1,476.

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, 2009 to December 31, 2009)
All equipment is being maintained and replaced as necessary to maintain compliance with regulatory guidelines for response readiness.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
The variance for this project is expected to be $14,111 or 12.7% lower than previously projected.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
All deadlines, both state and federal, have been met. Ongoing costs will be annual in nature and will consist of equipment upgrades/replacements. In 2009, PGD will have purchased the following: 6 new Munson boat motors, 1 replacement Skiff boat, 1 replacement 25hp motor, 1 new Conex box, and other equipment to be determined. PGD continues to assess our oil spill readiness at all applicable Florida facilities and is taking action based on these assessments.

Project Projections
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures (depreciation and return) for the period January 2010 through December 2010 are expected to be $133,940.

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, 2009 to December 31, 2009)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
The variance in depreciation and return is $0.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
All activities are complete.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures (depreciation and return) for the period January 20010 through December 2010 are expected to be $9,194.

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 Control Act, as amended, the Federal Clean Water Act, as amended, and the rules and regulations promulgated there under, 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 the 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, 2009 to December 31, 2009)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
There is no variance expected for this project.

Project Progress Summary:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures (depreciation and return) for the period January 2010 through December 2010 are expected to be $59,764.

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, 2009 to December 31, 2009)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
Project expenditures are estimated to be $0.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
All activities are complete.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures (depreciation and return) for the period January 2010 through December 2010 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, 2009 to December 31, 2009)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
The variance in depreciation and return is estimated to be $0.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
All activities are complete.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures (depreciation and return) for the period January 2010 through December 2010 are expected to be $231,248.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **St. Lucie Turtle Net**
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, 2009 to December 31, 2009)
Installation of a new turtle new was completed in 2009. Project is complete.

Project Fiscal Expenditures:
(January 1, 2009 – December 31, 2009)
Project depreciation and return on investment are estimated to be $23,293 or 16.9% lower than originally projected, primarily due to lower than projected costs of the turtle net. In addition, the project was completed earlier than estimated in the 2009 projections.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
The original estimate was related to the cost to re-coat the net once removed. When the net was being removed, a lot of sea grass was tangled in the net and the net needed to be cut to remove. The cost to re-coat and repair the net is greater than the cost to purchase a new net. The new net is considered a capital cost.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures (depreciation and return) for the period January 2010 through December 2010 are expected to be $114,400.

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, 2009 to December 31, 2009)
No projects for 2009 cycle.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
Project depreciation and return on investment are estimated to be $0 versus an original projection of $6,395. The installation of leak detection devices at the Martin 30" pipeline has been postponed due to the continuation of analyses on other technology options.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
No projects for 2009 cycle.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures (depreciation and return) for the period January 2010 through December 2010 are expected to be $6,395.

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, 2009 to December 31, 2009)
Two new projects have been identified for implementation in 2010 as follows:

- Investigate and increase the secondary containment as needed for the metering tanks at PPE.
- Provide containment or diversion for the lube oil system reservoirs at PFM GTs.

Also, at Plant Port St. Lucie facility upgrades have been completed on 2 of 3 identified areas for compliance with SPCC regulations. For the remaining area, the containment structure has been installed; however, a temporary process is being utilized to maintain the capacity margin of the containment structure due to rainwater collection. The installation of the permanent system has not been completed due to engineering delays at unit 1, where diesel Oil Storage Tank delays are due to a necessary design change to reduce displaced volume within the containment area to ensure that volume margin is maintained. Lead time for the manufacturing of the engineering specified filtration system also attributed to the delays.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
The variance in depreciation and return is $144,709 or 5.7% higher than originally projected.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
Progress in 2009 includes planning for the two new projects to be implemented in 2010. The current EPA compliance deadline for implementation of the SPCC plans is November 10, 2010. In addition, at Plant Port St. Lucie installation of the permanent rainwater removal system is expected by 12/31/09.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures for the period January 2010 through December 2010 are expected to be $2,672,333.

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, and 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, 2009 to December 31, 2009)
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. Both Unit's are out of warranty. New permit limits have been accepted by the FDEP. Continuing to incur on-going operating and maintenance costs.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
The variance in depreciation and return is $1,342 or 0.03% lower than originally projected.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
Unit 1 and 2 both completed.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures (depreciation and return) for the period January 2010 through December 2010 are expected to be $4,446,890.

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, 2009 to December 31, 2009)
During July U3 OH was completed including addition of Hopper Hammers. U4 Hopper Hammers will be installed in the Fall. Work on Insulator failures is in the Analysis stage.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
Estimated depreciation and return is $76,902 or 0.7% lower than originally projected.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
At this time, all four ESP's (Units 1 through 4) have construction activities completed and are operational. The Units 1-4 precipitators met all performance guarantees and permit requirements. The Units 1-4 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 completed to contain fugitive airborne ash during truck loadings.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures (depreciation and return) for the period January 2010 through December 2010 are expected to be $10,877,274.

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, 2009 to December 31, 2009)
There were no activities in 2009.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
The variance in depreciation and return is estimated to be $1.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
Initial review of the scope of work has been completed.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures (depreciation and return) for the period January 2010 through December 2010 are expected to be $64,011.

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, the installation of SCR's on SJRPP Units 1 and 2, installation of a Scrubber and SCR on Scherer Unit 4, and the installation of CEMS 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. Project completion is scheduled for the first quarter of 2009. The Scrubber and SCR installation on Scherer Unit 4 are projected to be completed in the first quarter of 2012. 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, 2009 to December 31, 2009)
- Completed Manatee 2 and began Martin 2 implementation
- Utilized Non-Outage time frames to pre-fabricate Martin and Manatee Boiler and Main Steam Drains

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
Project depreciation and return on investment are estimated to be $910,830 or 3.9% lower than originally projected, due to the delay of the Martin Plant Fall outage from September to December 2009. The outage will result in a delay in capital activities and expenditures associated with the 800 MW cycling project planned for 2009. Secondly, costs associated with FGD controls at Plant Scherer Unit 4 were less than originally projected. This was primarily due to delays in contractual agreement for engineering, construction and procurement of the controls. The project is expected to be placed in service in 2012 and total project estimates remain unchanged.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
The 800 MW Cycling Project identified countermeasures to assist with assuring operating reliability are currently in-progress with Project scope, Outage planning, and implementation for 2008 including; Condenser Tube replacements, Steam Turbine projects, Boiler projects, and Balance of Plant projects. The projected schedule to begin cycling is; PMR 2 in December 2009, PMR 1 in December 2010, with PMT 1 and PMT 2 scheduled for June 2010.

Installation of the SCR on SJRPP Unit 1 is complete and performance/acceptance testing in progress. Installation of the Scrubber and SCR on Scherer Unit 4 will be completed in 2012. Installation of support steel for SCR in progress. Scrubber vessel and foundation work in progress. Erection of scrubber chimney shell in progress along with fiberglass liner cans.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures (depreciation and return) for the period January 2010 through December 2010 are expected to be $40,355,064.

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. In addition to the CAMR, the Georgia Environmental Protection Division (EPD) adopted state specific rules as part of its Multi-Pollutant Rules requiring the installation of mercury controls on coal fired electric generating units within Georgia including all four units at Plant Scherer. The CAMR, and the Georgia Multi-Pollutant rule, are 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 State of Florida has begun the implementation of the requirements for reduction of Hg through rule making process. Units 1 & 2 of Plant St. Johns River Power Park (SJRPP), which FPL has 20% ownership shares, are affected units under this rule and will require the installation of HgCEMS. Similarly the State of Georgia, in addition to the adoption of their state specific mercury reduction requirements under the Multi-Pollutant rule, has also begun their rule making process to implement the federal rule which will affect FPL's ownership share of Plant Scherer Unit 4 requiring the installation of HgCEMS and Hg controls.

Project Accomplishments:
(January 1, 2009 to December 31, 2009)
Construction completed on bag house pilings and foundations. Construction in progress for structural steel, compartments and plenums, activated carbon equipment, inlet and outlet ducts.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
Project depreciation and return on investment are estimated to be $661,242 or 11.1% higher than originally projected, primarily due to contract progress payments for engineered materials occurring earlier than originally forecasted. Additionally, site common construction activities associated with foundation and pilings were completed earlier than estimated. The CAMR controls are on schedule to be completed in 2010 and total project estimates remain unchanged.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
The FPL CAMR project at Plant Scherer includes FPL's costs from the installation of a Bag house, 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 Georgia Multi-Pollutant Rule. Installation of controls requires a specific sequence for the construction of the controls and material handling systems. The bag house on Unit 4 is projected to be completed in early 2010. The FPL CAMR project at SJRPP includes FPL's costs from the installation of HgCEMS on Scherer 4.

Project Projections:
(January 1, 2010 - December 31, 2010)
Estimated project fiscal expenditures (depreciation and return) for the period January 2010 through December 2010 are projected to be $12,346,015.

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. A condition of the forthcoming BO will also require the addition of marine animal excluder devises (turtle excluder)

Project Accomplishments:
(January 1, 2009 thru December 31, 2009)
Turtle excluder design documents (drawings and calculations) were initiated in the spring of 2009.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
Project depreciation and return on investment are estimated to be $0 versus our original projection of $19,518.
Project Progress Summary:
(January 1, 2009 to December 31, 2009)
The turtle excluder design package documents (drawings and calculations) were started in the spring of 2009 and final design documents are scheduled for completion by the end of 2009.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures (depreciation and return) for January 2010 through December 2010 are expected to be $0.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Martin Plant Drinking Water System Compliance – Capital**
Project No. 35

Project Description:
The Martin Drinking Water System is required to comply with the requirements the Florida Department of Environmental regulations rules for drinking water systems. The Florida Department of Environmental Protection (FDEP) determined the system must be brought into compliance with newly imposed drinking water rules for TTHM (trihalomethanes) and HAA5 (Haleo Acetic Acid). The upgrades to the potable water system will cause FPL to incur Capital costs for major component upgrades to the system in order to comply with the new requirements. These include Nano filtration, air stripping, carbon and multimedia filtration. The operation of the Potable system will cause FPL to incur O&M costs for certain products that are consumed during the water treatment process. These include carbon and multimedia bed media and nano filtration media.

Project Accomplishments:
(January 1, 2009 to December 31, 2009)
System is in service and operating as designed.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
Depreciation and return are estimated to be $361 or 1.3% higher than projected.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
The installation was approved by FDEP, the capital installation was completed, and system is in service.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures (depreciation and return) for January 2010 through December 2010 are expected to be $29,488.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Low Level Radioactive Waste - Capital**
Project No. 36

Project Description:
The Barnwell, South Carolina radioactive waste disposal facility is the only site of its kind presently available to FPL for disposal of Low Level Waste (LLW) such as radioactive spent resins, filters, activated metals, and other highly contaminated materials. The Barnwell facility ceased accepting LLW from FPL June 30th, 2008. This project will construct a LLW storage facility for class B and C radioactive waste at the St. Lucie Plant (PSL). Turkey Point (PTN) will be implementing a similar project; however the PTN project will start later than the PSL project since PTN has some limited existing LLW storage capacity. Where practical, this project will be implemented as part of a fleet approach. The objective at PSL and PTN is to ensure construction of a LLW storage facility with sufficient capacity to store all LLW B and C class waste generated at each plant site over a 5 year period. This will allow continued uninterrupted operation of the PSL and PTN nuclear units until an alternate solution becomes available. The LLW on site storage facilities at PSL and PTN will also provide a "buffer" storage capacity for LLW even if an alternate solution becomes feasible, should the alternate solution be delayed or interrupted at a later date.

Project Accomplishments:
(January 1, 2009 to December 31, 2009)
The St. Lucie environmental and building permits were initiated and are close to being completed. The Engineering Design specifications for the St. Lucie LLW Storage Facility were completed. The Project Plan is projected to be completed mid August. FPL entered the Request For Bids process first quarter of 2009. The second round of bids were received from the Engineering Vendors in June and are presently undergoing commercial and technical review. The Turkey Point Level 1 schedule has been created. The Turkey Point LLW facility "need date" is confirmed to be mid year 2011. Initial project meetings have been held at Turkey Point to get stakeholder input.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
The variance in depreciation and return is estimated to be $0.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
The project at St. Lucie has experienced some schedule delays due to a project re-scope that occurred late 4th quarter 2008. The project re-scope was due to an option that was developed to ship St. Lucie and Turkey Point LLW to an off-site vendor that would take possession of the LLW until permanent disposal occurred. The St. Lucie and Turkey Point LLW projects were reviewed and the options (which included: No build, a reduced capacity facility and the original concept) were presented to the St. Lucie Plant Review Board (PRB) for evaluation. The St. Lucie PRB determined it was prudent to continue with the original LLW Storage facility since there is a high risk the offsite disposal option may not occur or be interrupted. Turkey Point determined that plans to build a LLW facility at the site should also proceed.

The St. Lucie LLW schedule delay has shifted some of the projected 2009 expenditures for the Engineering Design work into first quarter 2010. Construction of the PSL LLW facility is projected to start first quarter 2010 with a facility completion of July 2010

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures (depreciation and return) for January 2010 through December 2010 are expected to be $773,224.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **DeSoto Next generation Solar Energy Center – Capital**
Project No. 37

Project Description:
The DeSoto Next Generation Solar Energy Center ("DeSoto Solar") project is a zero greenhouse gas emitting renewable generation project which on August 4, 2008, the Commission found in Order Number PSC-08-0491-PAA-EI, to be eligible for recovery through the ECRC pursuant to House Bill 7135. The DeSoto Solar project is a 25 MW solar photovoltaic generating facility which will convert sunlight directly into electric power. The facility will utilize a tracking array that is designed to follow the sun as it traverses through the sky. In addition to the tracking array this facility will utilize cutting edge solar panel technology. The project will involve the installation of the solar PV panels and tracking system and electrical equipment necessary to convert the power from direct current to alternating current and to connect the system to the FPL grid.

Project Accomplishments:
(January 1, 2009 to December 31, 2009)
The project commenced construction in January 2009. Substation construction has been completed, and the majority of the solar equipment has been installed.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
Project depreciation and return on investment are estimated to be $353,819 or 3.2% lower than originally projected, primarily due to lower than projected site preparation costs. Original estimates were prepared prior to final site surveys and plans. Additionally, costs associated with the construction of a facility wind wall have been removed from estimates, as the wind wall was not required to comply with Florida Building Codes.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
The project commenced construction in January 2009. Substation construction has been completed, and the majority of the solar equipment has been installed. The scheduled completion date is October 31, 2009.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures (depreciation and return) for January 2010 through December 2010 are expected to be $21,496,699.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Space Coast Next generation Solar Energy Center - Capital**
Project No. 38

Project Description:
The Space Coast Next Generation Solar Energy Center ("Space Coast Solar") project is a zero greenhouse gas emitting renewable generation project which on August 4, 2008, the Commission found in Order Number PSC-08-0491-PAA-EI, to be eligible for recovery through the ECRC pursuant to House Bill 7135. The Space Coast Solar project is a 10 MW solar photovoltaic (PV) generating facility which will convert sunlight directly into electric power. The facility will utilize a fixed PV array oriented to capture the maximum amount of electricity from the sun over the entire year. The project will involve the installation of the solar PV panels and support structures and electrical equipment necessary to convert the power from direct current to alternating current and to connect the system to the FPL grid.

Project Accomplishments:
(January 1, 2009 to December 31, 2009)
In April 2009, the Environmental Resource Permit was issued by the Water Management District. Construction was initiated on June 1, 2009.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
Project depreciation and return on investment are estimated to be $150,585 or 10% lower than originally projected due to excluding the lease cost from depreciation to reflect a depreciation period consistent with FPL's in-service date of the entire solar project. Additionally, changes in the timing of capital expenditures lowered the net average investment.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
Construction (earthwork) was initiated on June 1, 2009. Panel installation is scheduled to commence in September 2009. The project is expected to be completed in March 2010.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures (depreciation and return) for January 2010 through December 2010 are expected to be $8,610,961.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Martin Next Generation Solar Energy Center - Capital
Project No. 39

Project Description:
The Martin Next Generation Solar Energy Center ("Martin Solar") project is a zero greenhouse gas emitting renewable generation project which on August 4, 2008, the Commission found in Order Number PSC-08-0491-PAA-EI, to be eligible for recovery through the ECRC pursuant to House Bill 7135. The Martin Solar project is a 75 MW solar thermal steam generating facility which will be integrated into the existing steam cycle for the Martin Unit 8 natural gas-fired combined cycle power plant. The steam to be supplied by Martin Solar will be used to supplement the steam currently generated by the heat recovery steam generators. The project will involve the installation of parabolic trough solar collectors that concentrate solar radiation. The collectors will track the sun to maintain the optimum angle to collect solar radiation. The collectors will concentrate the sun's energy on heat collection elements located in the focal line of the parabolic reflectors. These heat collection elements contain a heat transfer fluid which is heated by the concentrated solar radiation to approximately 750 degrees Fahrenheit. The heat transfer fluid is then circulated to heat exchangers that will produce up to 75 MW of steam that will be routed to the existing natural gas-fired combined cycle Unit 8 heat recovery steam generators.

Project Accomplishments:
(January 1, 2009 to December 31, 2009)
The project commenced construction in January 2009 which involved the initial site mobilization, land clearing activities and the establishment of construction facilities such as temporary offices and parking areas. All major equipment contracts have been signed, including mirrors, heat collection elements, space frames, solar heat exchangers, and heat transfer fluid. Engineering and construction progress to date currently supports the planned commercial operation date by the end of 2010.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
Project depreciation and return on investment are estimated to be $4,305,455 or 36.5% lower than originally projected due to the timing of procurement of major solar field equipment. This included awarding purchase orders and payments for solar field mirrors, solar field tubes, heat exchangers, and the engineering, procurement, construction (EPC) contract. Due to lower commodity prices and increased market knowledge, mirrors and heat exchanger awards were postponed into 2009, which led to the cumulative average net investment being significantly lower than originally expected.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
The project commenced construction in January 2009 with the initial site clearing of approximately 600 acres. Earthwork commenced in April 2009 and is expected to be completed in October 2009. Installation of foundations for the solar collection assemblies commenced in June 2009 and is expected to be complete in January 2010. Solar collection assembly installation commenced in July 2009 with the initial installation of the pylons which will support the frames, heat collection elements, and mirrors. Frame installation will commence in August 2009 followed by mirror installations in October 2009. The frame and mirror installations are expected to be completed in May 2010, followed by the final installation of the electrical systems, control systems, and the steam plant. Commissioning activities for the solar fields are expected to commence with the initial loading of the heat transfer fluid in August 2010. The final commercial operation date is still projected to be by the end of 2010. Overall project costs remain within the initial estimate of $476.3 million.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures (depreciation and return) for January 2010 through December 2010 are expected to be $39,635,837.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Manatee Temporary Heating System Project – Capital**
Project No. 41

Project Description:
Due to the specific and continuing legal requirement for FPL to endeavor to provide a warm water refuge for the endangered manatee at its Riviera (PRV) and Cape Canaveral Plants (PCC), FPL has to factor its unique obligation into otherwise continue routine and normal operation and maintenance considerations and decisions. FPL undertakes to design, engineer, purchase, and install a temporary manatee heating system at both PRV and PCC ("the Project") pursuant to PRV's and PCC's Manatee Protection Plans (MPP), as part of the State Industrial Wastewater Facility Permit Numbers FL0001546, Specific Condition 13, issued on February 16, 1998 and FL0001473, Specific Condition 9, issued on August 10,2005, respectively. In order to comply with the respective MPP's, FPL will pursue installing a temporary manatee heating system endeavoring to avoid potential adverse impacts to manatees congregating at PRV's and PCC's manatee embayment area during the annual period from November 15 to March 31 at PRV and the annual period of October 15 to March 31 at PCC. Due to the prescribed annual period for providing warm water and the time required to design, engineer, purchase, and install the manatee heating system, the Project will begin immediately.

Project Accomplishments:
(January 1, 2009 to December 31, 2009)
Work on this project is expected to begin in the last quarter of 2009.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009
This project was not anticipated when original estimates for 2009 were filed on August 29, 2008. Project depreciation and return on investment are estimated to be $22,849.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
2009 capital expenditures will include the engineering & management costs, installation costs, equipment costs, electrical feed cost, and dredging costs.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures (depreciation and return) for January 2010 through December 2010 are expected to be $707,489.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Turkey Point Cooling Canal Monitoring Plan - Capital
Project No. 42

Project Description:

Pursuant to Conditions IX and X of the Florida Department of Environmental Protection's (FDEP) Final Order Approving Site Certification, filed October 29, 2008, FPL submitted its initial draft of the proposed Cooling Canal Monitoring Plan associated with FPL's Turkey Point Uprate Project to the South Florida Water Management District (SFWMD). This plan requires an assessment of baseline conditions to provide information on the vertical and horizontal extent of the hypersaline groundwater plume and effect of that plume on ground and surface water quality, if any. Comments, concerns and requests for revisions or action items were received from the SFWMD as well as the FDEP. Miami-Dade Department of Environmental Resource Management (DERM) has incorporated into the current draft the proposed monitoring plan, dated July 16, 2009.

The CCM Plan has not yet been finalized or agreed upon by FPL and the agencies and is therefore subject to change based on input from the agencies. FPL expects a revised monitoring plan to be approved by mid September 2009.
The objective of FPL's CCM Plan is to implement the Conditions of Certification IX and X, which states that "the Revised Plan shall be designed to be in concurrence with other existing and ongoing monitoring efforts in the area and shall include but not necessarily be limited to surface water, groundwater and water quality monitoring, and ecological monitoring to: delineate the vertical and horizontal extent of the hyper-saline plume that originates from the cooling canal system and to characterize the water quality including salinity and temperature impacts of this plume for the baseline condition; determine the extent and effect of the groundwater plume on surface water quality as a baseline condition; and detect changes in the quantity and quality of surface and groundwater over time due to the cooling canal system associated with the Uprate Project. The Revised Plan shall include installation and monitoring of an appropriate network of wells and surface water stations.

Project Accomplishments:
(January 1, 2009 to December 31, 2009)
FPL is still in negotiation with Florida Department of Environmental Protection, South Florida Water Management District and Miami-Dade Department of Environmental Resource Management in developing the CCM Plan. The deadline has been extended to October 16, 2009. If the plan is approved we anticipate purchasing monitoring equipment in 2009.

Project Fiscal Expenditures:
(January 1, 2009 to December 31, 2009)
There is no variance expected for this project.

Project Progress Summary:
(January 1, 2009 to December 31, 2009)
The agencies and FPL have yet to agree on the CCM Plan. FPL is still in negotiations to develop a CCM Plan that will accomplish the intent and comply with of the FDEP Conditions of Certification.

Project Projections:
(January 1, 2010 to December 31, 2010)
Estimated project fiscal expenditures (depreciation and return) for the period January 2010 through December 2010 are expected to be $118,701.

Form 42-6P

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Energy & Demand Allocation % By Rate Class
January 2010 to December 2010

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	64.192%	59.240%	52,217,498,280	9,286,047	10,062,213	1.08576889	1.06788768	55,762,423,094	10,082,501	10,925,238	51.75337%	56.57483%	55.17199%
GS1/GST1/WIES1	65.233%	55.933%	5,768,906,942	1,009,543	1,177,389	1.08576889	1.06788768	6,160,544,650	1,096,130	1,278,372	5.71763%	6.15059%	6.45572%
GSD1/GSDT1/HLFT1 (21-499 kW)	76.245%	68.497%	24,314,106,089	3,640,350	4,052,141	1.08568434	1.06782291	25,963,159,518	3,952,271	4,399,346	24.09653%	22.17695%	22.21651%
OS2	60.006%	16.269%	13,561,632	2,580	9,516	1.05367460	1.04305089	14,145,473	2,718	10,027	0.01313%	0.01525%	0.05064%
GSLD1/GSLDT1/CS1/CST1/HLFT2 (500-1,999 kW)	78.726%	69.381%	10,871,856,337	1,576,445	1,788,781	1.08455272	1.06699165	11,600,179,931	1,709,738	1,940,027	10.76618%	9.59367%	9.79705%
GSLD2/GSLDT2/CS2/CST2/HLFT3 (2,000+ kW)	88.190%	77.797%	2,052,798,432	265,720	301,217	1.07600621	1.06018236	2,176,340,686	285,916	324,111	2.01987%	1.60433%	1.63675%
GSLD3/GSLDT3/CS3/CST3	95.582%	65.692%	234,597,527	28,018	40,767	1.02665485	1.02205318	239,771,149	28,765	41,854	0.22253%	0.16141%	0.21136%
ISST1D	99.926%	46.818%	0	0	0	1.05367460	1.04305089	0	0	0	0.00000%	0.00000%	0.00000%
ISST1T	114.364%	33.656%	0	0	0	1.02665485	1.02205318	0	0	0	0.00000%	0.00000%	0.00000%
SST1T	114.364%	33.656%	131,305,945	13,107	44,536	1.02665485	1.02205318	134,201,659	13,456	45,723	0.12455%	0.07550%	0.23090%
SST1D1/SST1D2/SST1D3	99.926%	46.818%	7,094,737	811	1,730	1.05367460	1.04305089	7,400,172	855	1,823	0.00687%	0.00480%	0.00921%
CILC D/CILC G	91.935%	85.033%	3,182,827,924	395,209	427,286	1.07491341	1.05988309	3,373,425,495	424,815	459,295	3.13089%	2.38372%	2.31942%
CILC T	97.893%	85.883%	1,503,359,195	175,311	199,825	1.02665485	1.02205318	1,536,513,046	179,984	205,151	1.42605%	1.00992%	1.03600%
MET	65.759%	57.099%	79,605,290	13,819	15,915	1.05367460	1.04305089	83,032,369	14,561	16,769	0.07706%	0.08170%	0.08468%
OL1/SL1/PL1	351.558%	49.125%	573,716,639	18,629	133,318	1.08576889	1.06788768	612,664,930	20,227	144,753	0.56862%	0.11350%	0.73100%
SL2, GSCU1	100.004%	99.351%	77,397,030	8,835	8,893	1.08576889	1.06788768	82,651,335	9,593	9,656	0.07671%	0.05383%	0.04876%
TOTAL			101,028,632,000	16,434,424	18,263,527			107,746,453,507	17,821,530	19,802,145	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 2010 through December 2010
(4) Calculated: (Col 3)/(8,760 * Col 1)
(5) Calculated: (Col 3)/8,760 * Col 2)
(6) Based on 2008 demand losses
(7) Based on 2008 energy losses
(8) Col 3 * Col 7
(9) Col 1 * Col 6
(10) Col 2 * Col 6
(11) Col 8 / total for Col 8
(12) Col 9 / total for Col 9
(13) Col 10 / total for Col 10

Form 42-7P

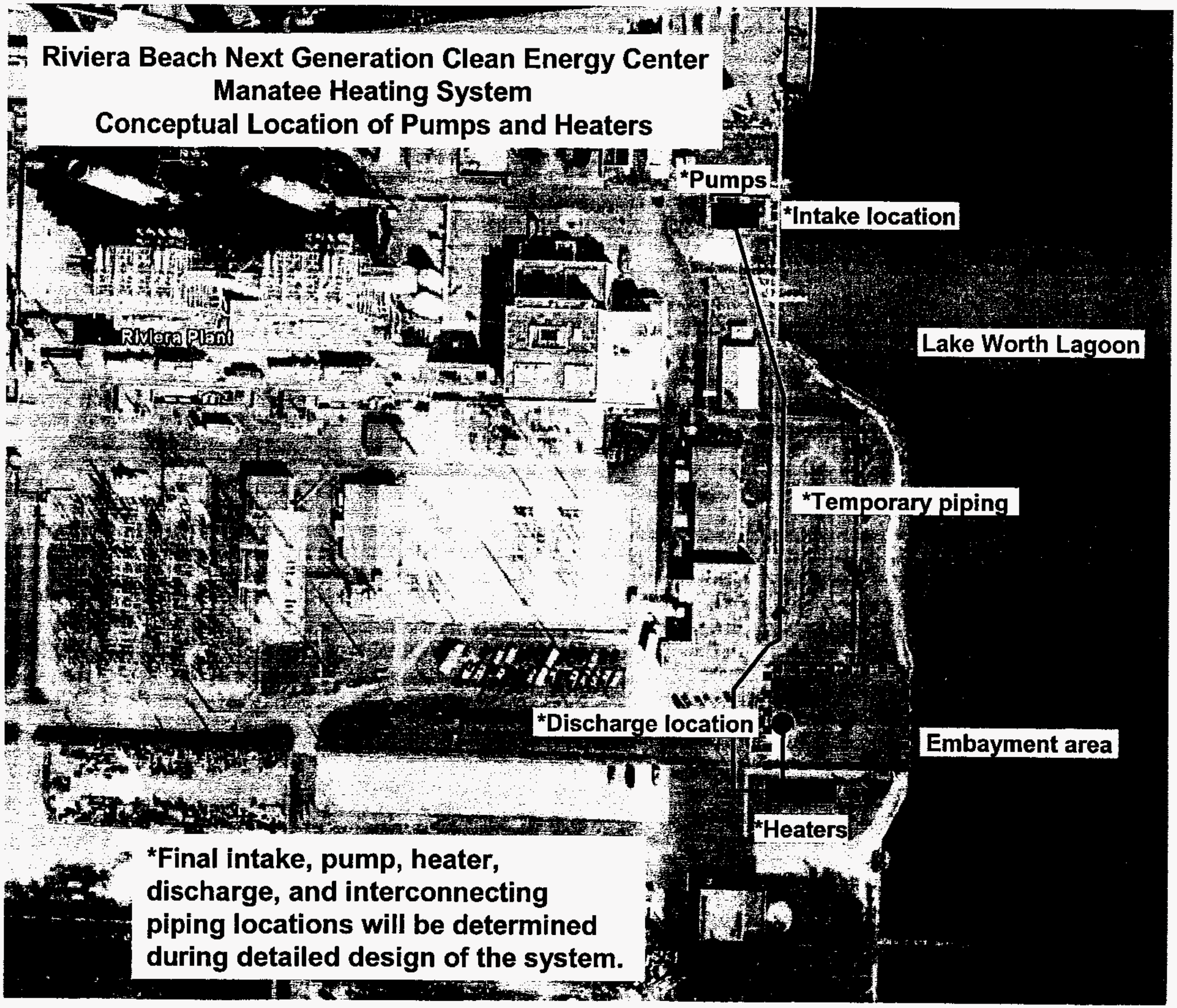
Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of Environmental Cost Recovery Clause Factors
January 2010 to December 2010

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	51.75337%	56.57483%	55.17199%	$22,171,313	$69,962,152	$1,134,041	$93,267,506	52,217,498,280	0.00179
GS1/GST1	5.71763%	6.15059%	6.45572%	$2,449,452	$7,606,011	$132,695	$10,188,158	5,768,906,942	0.00177
GSD1/GSDT1/HLTF(21-499 KW)	24.09653%	22.17695%	22.21651%	$10,323,033	$27,424,682	$456,653	$38,204,368	24,314,106,089	0.00157
OS2	0.01313%	0.01525%	0.05064%	$5,624	$18,860	$1,041	$25,525	13,561,632	0.00188
GSLD1/GSLDT1/CS1/CST1/HLTF(500-1,999 KW)	10.76618%	9.59367%	9.79705%	$4,612,268	$11,863,817	$201,375	$16,677,460	10,871,856,337	0.00153
GSLD2/GSLDT2/CS2/CST2/HLTF(2,000+ KW)	2.01987%	1.60433%	1.63675%	$865,320	$1,983,962	$33,643	$2,882,925	2,052,798,432	0.00140
GSLD3/GSLDT3/CS3/CST3	0.22253%	0.16141%	0.21136%	$95,334	$199,599	$4,344	$299,277	234,597,527	0.00128
ISST1D	0.00000%	0.00000%	0.00000%	$0	$0	$0	$0	0	0.00128
ISST1T	0.00000%	0.00000%	0.00000%	$0	$0	$0	$0	0	0.00115
SST1T	0.12455%	0.07550%	0.23090%	$53,359	$93,371	$4,746	$151,476	131,305,945	0.00115
SST1D1/SST1D2/SST1D3	0.00687%	0.00480%	0.00921%	$2,942	$5,933	$189	$9,064	7,094,737	0.00128
CILC D/CILC G	3.13089%	2.38372%	2.31942%	$1,341,284	$2,947,778	$47,675	$4,336,737	3,182,827,924	0.00136
CILC T	1.42605%	1.00992%	1.03600%	$610,922	$1,248,903	$21,295	$1,881,120	1,503,359,195	0.00125
MET	0.07706%	0.08170%	0.08468%	$33,014	$101,038	$1,741	$135,793	79,605,290	0.00171
OL1/SL1/PL1	0.56862%	0.11350%	0.73100%	$243,597	$140,355	$15,025	$398,977	573,716,639	0.00070
SL2, GSCU1	0.07671%	0.05383%	0.04876%	$32,862	$66,566	$1,002	$100,430	77,397,030	0.00130
TOTAL				$42,840,325	$123,663,026	$2,055,465	$168,558,816	101,028,632,000	0.00167

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 2010 through December 2010
(9) Col 7 / Col 8 x 100

Docket No. 090007-EI
RBEC Manatee Heating System
Conceptual Location of
Pumps & Heaters
Exhibit RRL-1, Page 1 of 1



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 6
COMPANY Florida Power & Light Company (Direct)
WITNESS R. R. Labauve (RRL-1)
DATE 11/02/09

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

NOTICE OF PERMIT

CERTIFIED MAIL

In the Matter of an
Application for Permit by:
Florida Power & Light Company
200-300 Broadway
Riviera Beach, Florida 33404

DEP File # FL00001546-003- IW1S/NR

Attention: Mr. Rick Blomgren

Enclosed is Permit Number FL00001546 to Florida Power & Light Company, 200-300 Broadway, Riviera Beach, FL 33404, to operate wastewater treatment and effluent disposal facilities for Units 2, 3 and 4 of the FPL Riviera Beach Plant located in Palm Beach County, Florida, issued under Section 403.0885, Florida Statutes and DEP Rule 62-620, Florida Administrative Code.

Any party to this order (permit) has the right to seek judicial review of the permit under Section 120.68, Florida Statutes, by the filing of a Notice of Appeal under Rules 9.110 and 9.190, Florida Rules of Appellate Procedure, with the Clerk of the Department of Environmental Protection, Office of General Counsel, Mail Station 35, 3900 Commonwealth Boulevard, Tallahassee, Florida 32399-3000 and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate district court of appeal. The notice of appeal must be filed within thirty days after this notice is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Mimi Drew

Mimi Drew
Director
Division of Water Resource Management

2600 Blair Stone Road
Tallahassee, FL 32399-2400
(850) 245-8336

"More Protection, Less Pr

Printed on recycled pape

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 7
COMPANY Florida Power & Light Company (Direct)
WITNESS R. R. Labauve (RRL-2)
DATE 11/02/09

Florida Power & Light Company
Riviera Plant
Facility ID Number FL00001546

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF PERMIT and all copies were mailed before the close of business on 02-03-04 to the listed persons.

[Clerk Stamp]

FILING AND ACKNOWLEDGMENT

FILED, on this date, under Section 120.52 (9), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

S. Shields 02-03-04
(Clerk) (Date)

Copies furnished to:

Chairman, Board of Palm Beach County Commissioners
Jill Watson - FPL Juno Beach
Betsy Hewitt - DEP Tallahassee
Tim Powell –DEP West Palm Beach

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION
2600 BLAIR STONE ROAD
TALLAHASSEE, FLORIDA 32399-2400

SECOND AMENDMENT TO THE FACT SHEET FOR APPLICATION FOR PERMIT TO DISCHARGE TREATED WASTEWATER TO WATERS OF THE STATE

Permit Number: FL0001546
Permit Writer: Bala Nori

Application Date: August 19, 2002
Application No: FL0001546-003-IW1S/NR
Notice of Intent Issued: November 5, 2003;

1. SYNOPSIS OF APPLICATION

A. Name and Address of Applicant
Florida Power & Light Company
200- 300 Broadway
Riviera Beach, Florida 33404
For:
Riviera Power Plant
200-300 Broadway
Riviera Beach, FL 33404

2. MINOR CHANGES TO THE PROPOSED PERMIT

The following changes are based on comments from the Permittee during November and December 2003. They are intended to correct minor errors in the Proposed Permit, and provide non-substantive changes in language to clarify certain permit conditions.

1. Item I.E.9. was reworded to clarify monitoring requirements in the event of a bypass.
2. Item I.E.14., stormwater monitoring requirements for discharge from diked petroleum storage areas which were in the Draft Permit but were deleted from the Proposed Permit, were reinserted into the Final Permit. The requirements are in the permit because the stormwater discharges are not covered under the Multi-Sector General Permit (MSGP), or another individual permit.
3. Items II. (Industrial Sludge Management Requirements) and IV. (Other Land Application Requirements). In the Proposed Permit, requirements for both industrial sludge management and maintenance of settling and percolation basins were all located in Item II. In the Final Permit, Item II. includes only the specific requirements for industrial sludge management, while requirements for settling and percolation basin maintenance have been moved to Item IV.

3. SIGNIFICANT CHANGES TO PERMIT CONDITIONS

The changes to permit conditions described herein are not considered significant because they do not change effluent limitations, monitoring, or affect the quantity or quality of discharge.

STATE OF FLORIDA
INDUSTRIAL WASTEWATER FACILITY PERMIT

PERMITTEE:
Florida Power & Light Company
200-300 Broadway
Riviera Beach, Florida 33404

PERMIT NUMBER: FL0001546
PA FILE NUMBER: FL0001546-003-IW1S/NR
ISSUANCE DATE: February 10, 2004
EXPIRATION DATE: February 09, 2009

RESPONSIBLE AUTHORITY:

Mr. Rick Blomgren
Plant General Manager

FACILITY:

FPL-Riviera Plant
200-300 Broadway
Riviera Beach, FL 33404
Palm Beach County

Latitude: 26° 45' 55" N   Longitude: 80° 3' 10" W

This permit is issued under the provisions of Chapter 403, Florida Statutes, and applicable rules of the Florida Administrative Code and constitutes authorization to discharge to waters of the state under the National Pollutant Discharge Elimination System. The above named permittee is hereby authorized to operate the facilities shown on the application and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

The plant consists of three steam electric power generating units with a total name plate rating of 673 MW. Plant fuel is natural gas and oil. The plant has a Once Through Cooling Water (OTCW) system that uses water from Lake Worth, a coastal marine waterbody. The OTCW is intermittently chlorinated for bio-fouling control and dechlorinated prior to discharge. Discharges of OTCW and Auxiliary Equipment Cooling Water (ABCW) are discharged through a submerged pipeline approximately 2,000 feet in length via Lake Worth to the Intracoastal Waterway.

WASTEWATER TREATMENT:

All wastewaters except screen washwater from the operation of Units 3 and 4 are treated prior to discharge. Once through cooling water Auxiliary Equipment Cooling Water are intermittently chlorinated and dechlorinated using sodium bisulfite prior to discharge. Other wastewaters include water treatment plant effluent (reverse osmosis concentrate, softener regeneration, and filter backwash) low volume wastes and metal cleaning wastes. Wastewater treatment for curbed equipment areas consists of oil separation. Wastewater is routed to two solids settling basins. The solids settling basins are lined with HDPE membrane liners. Wastewater from the solids settling basins discharges to three unlined percolation/evaporation ponds.

EFFLUENT DISPOSAL:

Surface Water Discharge:

An existing discharge to Intracoastal Waterway [Lake Worth] (Class III Marine waters), **Outfall D-012/D0182,** The Once Through Cooling Water and auxiliary equipment cooling water outfall line is located approximately at latitude 26° 45'52" N/ 26° 45'57" N longitude 80° 03'03" W/ 80° 03'03" W.

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An existing discharge to Intracoastal Waterway [Lake Worth] (Class III Marine waters), Outfall D-013/D0183. The Once through cooling water and auxiliary equipment cooling water outfall line is located approximately at latitude 26° 45'52 " N/26° 45'52 " N, longitude 80°03 '02" W.

An existing discharge to Intracoastal Waterway [Lake worth] (Class III Marine waters), Outfall D-014/D0184. The Once through cooling water and auxiliary equipment cooling water outfall line is located approximately at latitude 26°45'52" N, longitude 80°03'02" W.

An existing discharge to Intracoastal Waterway [Lake Worth] (Class III Marine waters), Outfall D-0163. The Boiler blowdown from Unit 3 to the OTCW intake wells and then to the Intracoastal Waterway.[Lake Worth] outfall line is located approximately at latitude26°46'00" N, longitude80°03'09" W.

An existing discharge to Intracoastal Waterway [Lake Worth] (Class III Marine waters), Outfall D-0164. The Boiler blowdown from Unit 4 to intake well of OTCW and then to the Intracoastal Waterway outfall line is located approximately at latitude 26°46'00" N, longitude80°03'09" W.

An existing discharge to Inter Coastal Waterway [Lake Worth] (Class III Marine waters), Outfall D-009. The Intake Screen Washwater to Intracoastal Waterway outfall line is located approximately at latitude 26°45'59" N, longitude 80°03'03" W.

Land Application:

An existing 0.05 MGD, projected average flow rate land application system **Outfall R-001** consisting of an unlined percolation pond designated Basin EP-1, discharging to Class G-II ground water, and located approximately at latitude 26° 45' 53" N, longitude 80° 03' 13" W.

An existing 0.05 MGD, projected average flow rate land application system **Outfall R-002** consisting of an unlined percolation pond designated Basin EP-2, discharging to Class G-II ground water, and located approximately at latitude 26° 45' 53" N, longitude 80° 03' 14" W.

An existing 0.0003 MGD, projected average flow rate, land application system (**Outfall R-003**) consisting of an unlined percolation pond designated Basin EP-3, discharging to Class G-II ground water, and located approximately at latitude 26° 45' 55" N, longitude 80° 03' 15" W.

IN ACCORDANCE WITH: The limitations, monitoring requirements and other conditions as set forth in Part I through Part VIII on pages 3 through 23 of this permit.

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I. Effluent Limitations and Monitoring Requirements

A. Surface Water Discharges

1. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge from **Outfall D-012/D-0182 Once-Through Non-Contact Cooling Water and Auxiliary Equipment Cooling Water** from Unit 2 to the Intracoastal Waterway (Lake Worth).

a. Such discharge shall be limited and monitored by the permittee as specified below:

	Discharge Limitations			Monitoring Requirements		
Parameters (units)	**Monthly Average**	**Daily Maximum**	**Instantaneous Maximum**	**Monitoring Frequency**	**Sample Type**	**Sample Point**
Flow (MGD)	Report	Report	N/A	Daily	Pump logs	INT-1
Temperature of Discharge (°F)	Report, see I.A.1.d.	Report	N/A	6/Day	Recorder	EFF-1
Temp. Diff. Between Intake and Discharge (°F)	Report, see I.A.1.d.	Report	N/A	6/Day	Calculated	EFF-1

b. Effluent samples shall be taken at the monitoring site locations listed in permit condition I.A.1 and as described below:

Sample Point	Description of Monitoring Location
INT-1	Plant intake for Unit 2
EFF-1	Outlet corresponding to Unit 2 prior to discharging to receiving waters or mixing with other waste streams.

c. The discharge of TRO from the chlorination of D0012 or D0182 is not authorized to waters of the state by this permit.

d. Discharge from D-0012 is subject to the limitations established by Rule 62-302.520(1), F.A.C.

2. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge from **Outfall D-013/D-0183 Once-Through Cooling Water and Auxiliary Equipment Cooling Water** from Unit 3 to the Intracoastal Waterway (Lake Worth).

a. Such discharge shall be limited and monitored by the permittee as specified below:

	Discharge Limitations			Monitoring Requirements		
Parameters (units)	**Monthly Average**	**Daily Maximum**	**Instantaneous Maximum**	**Monitoring Frequency**	**Sample Type**	**Sample Point**
Flow (MGD)	Report	Report	N/A	Daily	Pump logs	INT-2
Temp. Diff. Between Intake and Discharge (°F)	Report, see I.A.2.f.	Report	N/A	6/Day	Calculation	EFF-2

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	Discharge Limitations			Monitoring Requirements		
Parameters (units)	Monthly Average	Daily Maximum	Instantaneous Maximum	Monitoring Frequency	Sample Type	Sample Point
Temperature of Discharge (°F)	Report, see I.A.2.f.	Report	N/A	6/Day	Recorder	EFF-2
Oxidants, Total Residual (MG/L)	N/A	N/A	0.01[1,2]	1/Week	Multiple Grabs[3]	EFF-4
Chlorination Duration AECW/ (MINUTES)	Report	1440	N/A	Daily	Logs	INT-2
Chlorination Duration OTCW/ (MINUTES)	Report	120	N/A	Daily	Logs	INT-2

b. Effluent samples shall be taken at the monitoring site locations listed in permit condition I.A.2. and as described below:

Sample Point	Description of Monitoring Location
INT-2	Plant intake for Unit 3
EFF-2	Outlet corresponding to Unit 3 prior to discharging to receiving waters or mixing with other waste streams.
EFF-4	The combined discharge of ABCW and OTCW at the seal well corresponding to Unit 3

c. Limitations and monitoring requirements for TRO are not applicable for any week in which chlorine is not added to Unit 3.

d. Discharge from D-0013 is subject to the limitations established by Rule 62-302.520(1), F.A.C.

[1] The discharge shall comply with a TRO limitation of 0.026 mg/l until the Permittee notifies the Department that the chlorination optimization study described in Section VI.4. of this permit has been completed, or until two years following issuance of this permit, whichever occurs first. At such time the discharge shall comply with the TRO limitation of 0.01 mg/l.

[2] The facility is authorized a mixing zone for TRO encompassing a circular area of 125,600 m^2 centered on the POD. Water Quality Standards (WQS) shall be achieved at the edge of the mixing zone. When the Permittee notifies the Department that the chlorination optimization study described in Section VI.4. of this permit has been completed, or two years following issuance of this permit, whichever occurs first, the mixing zone for TRO shall be eliminated and the limitation of 0.01 mg/l, which is the WQS, shall be applicable at the POD, as monitored at EFF-4.

[3] Multiple grabs shall consist of grab samples collected at approximately the beginning, middle, and end of the chlorination period.

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3. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **Once-Through Cooling Water and Auxiliary Equipment Cooling Water from Outfall D-014/D0184.**

a. Such discharge shall be limited and monitored by the permittee as specified below:

	Discharge Limitations			Monitoring Requirements		
Parameters (units)	**Monthly Average**	**Daily Maximum**	**Instantaneous Maximum**	**Monitoring Frequency**	**Sample Type**	**Sample Point**
Flow (MGD)	Report	Report	N/A	Daily	Pump logs	INT-3
Temp. Diff. Between Intake and Discharge (°F)	Report, see I.A.3.f.	Report	N/A	6/Day	Calculated	EFF-3
Temperature of Discharge (°F)	Report, see I.A.3.f.	Report	N/A	6/Day	Recorder	EFF-3
Oxidants, Total Residual (MG/L)	N/A	N/A	0.01[1,2]	1/Week	Multiple Grabs[3]	EFF-5
Chlorination Duration AECW (MINUTES)	Report	1440	N/A	Daily	Logs	INT-3
Chlorination Duration OTCW (MINUTES)	Report	120	N/A	Daily	Logs	INT-3

b. Effluent samples shall be taken at the monitoring site locations listed in permit condition I.A.3 and as described below:

Sample Point	Description of Monitoring Location
INT-3	Plant intake for Unit 4
EFF-3	Outlet corresponding to Unit 4 prior to discharging to receiving waters or mixing with other waste streams.
EFF-5	The combined discharge of AECW and OTCW at the seal well corresponding to Unit 4

c. Limitations and monitoring requirements are not applicable for any week during which chlorine is not added to Unit 4.

d. Discharge from D-0014 is subject to the limitations established by Rule 62-302.520(1), F.A.C.

[1] The discharge shall comply with a TRO limitation of 0.026 mg/l until the Permittee notifies the Department that the chlorination optimization study described in item VI.4. of this permit has been completed, or until two years following issuance of this permit, whichever occurs first. At such time the discharge shall comply with the TRO limitation of 0.01 mg/l.

[2] The facility is authorized a mixing zone for TRO encompassing a circular area of 125,600 m^2 centered on the POD. Water Quality Standards (WQS) shall be achieved at the edge of the mixing zone. When the Permittee notifies the Department that the chlorination optimization study described in Section VI.4. of this permit has been completed, or two years following issuance of this permit, whichever occurs first, the mixing zone for TRO shall be eliminated and the limitation of 0.01 mg/l, which is the WQS, shall be applicable at the POD, as monitored at EFF-5.

[3] Multiple grabs shall consist of grab samples collected at approximately the beginning, middle, and end of the chlorination period.

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4. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge Boiler Blowdown from Outfall D-0163.

a. Such discharge shall be limited and monitored by the permittee as specified below:

	Discharge Limitations			Monitoring Requirements		
Parameters (units)	Monthly Average	Daily Maximum	Instantaneous Maximum	Monitoring Frequency	Sample Type	Sample Point
Flow (MGD)	Report	Report	N/A	Semiannually	Calculated	EFF-6
Oil and Grease (MG/L)	15.0	20.0	N/A	Semiannually	Grab	EFF-6
Solids, Total Suspended (MG/L)	30.0	100.0	N/A	Semiannually	Grab	EFF-6
Hydrazine (MG/L)	N/A	N/A	0.30	Semiannually	Grab	EFF-6

b. Effluent samples shall be taken at the monitoring site locations listed in permit condition I.A.4 and as described below:

Sample Point	Description of Monitoring Location
EFF-6	Within boiler drum, flash tank or other location prior to discharge to receiving waters or mixing with any other streams from Unit 3.

5. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge Boiler Blowdown from Outfall D-0164.

a. Such discharge shall be limited and monitored by the permittee as specified below:

	Discharge Limitations			Monitoring Requirements		
Parameters (units)	Monthly Average	Daily Maximum	Daily Minimum	Monitoring Frequency	Sample Type	Sample Point
Flow (MGD)	Report	Report	N/A	Semiannually	Calculated	EFF-7
Oil and Grease (MG/L)	15.0	20.0	N/A	Semiannually	Grab	EFF-7
Solids, Total Suspended (MG/L)	30.0	100.0	N/A	Semiannually	Grab	EFF-7
Hydrazine (MG/L)	N/A	N/A	0.30	Semiannually	Grab	EFF-7

b. Effluent samples shall be taken at the monitoring site locations listed in permit condition I.A.5 and as described below:

Sample Point	Description of Monitoring Location
EFF-7	Within boiler drum, flash tank or other location prior to discharge to receiving waters or mixing with any other waste streams from Unit 4.

6. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **Intake Screen Wash Water from Outfall D-009.** Discharge of intake screen wash water is permitted without limitation or monitoring requirements.

B. Underground Injection Control Systems

This section is not applicable to this facility.

C. Land Application Systems

a. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge process wastewater, storm water, boiler make up water treatment wastewater, equipment area floor drains, curbed water treatment area floor drains, fuel oil burner pump and unloading equipment area drainage and low volume and metal cleaning wastewater to Land Application System R-001, a percolation pond designated Basin EP-1, R-002, a percolation pond designated Basin EP-2 and R-003, a percolation pond designated Basin EP-3. Discharge into Basins EP-1,2, and 3 is permitted without limitations and without monitoring, except as follows. The Permittee shall monitor discharge flow into Basins 1,2, and 3, and shall maintain a record of the monthly average discharge into each basin. Monitoring and limitations on discharge from Basins EP-1,2, and 3 to ground water are addressed in item III.B. of this permit.

D. Other Methods of Disposal or Recycling

There shall be no discharge of industrial wastewater from this facility to ground or surface waters, except as authorized by this permit.

E. Other Limitations and Monitoring and Reporting Requirements

1. The sample collection, analytical test methods and method detection limits (MDLs) applicable to this permit shall be in accordance with Rule 62-4.246, Chapter 62-160, and 40 CFR 136, as appropriate. The list of Department established analytical methods, and corresponding MDLs (method detection limits) and PQLs (practical quantification limits), which is titled "Florida Department of Environmental Protection Table as Required By Rule 62-4.246(4) Testing Methods for Discharges to Surface Water" dated June 21, 1996, is available from the Department on request. The MDLs and PQLs as described in this list shall constitute the minimum acceptable MDL/PQL values and the Department shall not accept results for which the laboratory's MDLs or PQLs are greater than those described above unless alternate MDLs and/or PQLs have been specifically approved by the Department for this permit. Any method included in the list may be used for reporting as long as it meets the following requirements:

   a. The laboratory's reported MDL and PQL values for the particular method must be equal or less than the corresponding method values specified in the Department's approved MDL and PQL list;

   b. The laboratory reported PQL for the specific parameter is less than or equal to the permit limit or the applicable water quality criteria, if any, stated in Chapter 62-302, F.A.C. Parameters that are listed as "report only" in the permit shall use methods that provide a PQL, which is equal to or less than the applicable water quality criteria stated in Chapter 62-302 FAC; and

   c. If the PQLs for all methods available in the approved list are above the stated permit limit or applicable water quality criteria for that parameter, then the method with the lowest stated PQL shall be used.

   Where the analytical results are below method detection or practical quantification limits, the permittee shall report the actual laboratory MDL and/or PQL values for the analyses that were performed following the instructions on the applicable discharge monitoring report. Approval of alternate laboratory MDLs or PQLs are not necessary if the laboratory reported MDLs and PQLs are less than or equal to the permit limit or the applicable water quality criteria, if any, stated in Chapter 62-302, F.A.C. However, where necessary, the permittee may request approval for alternative methods or for alternative MDLs and PQLs for any approved analytical method, in accordance with the criteria of Rules 62-160.520 and .530, F.A.C.

2. Monitoring requirements under this permit are effective on the first day of the second month following permit issuance. Until such time, the permittee shall continue to monitor and report in accordance with previously

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effective permit requirements, if any. During the period of operation authorized by this permit, the permittee shall complete and submit to the Southeast District Office Discharge Monitoring Reports (DMRs) in accordance with the frequencies specified by the REPORT type (i.e., monthly, toxicity, quarterly, semiannual, annual, etc.) indicated on the DMR forms attached to this permit. Monitoring results for each monitoring period shall be submitted in accordance with the associated DMR due dates below.

REPORT Type on DMR	Monitoring Period	DMR Due Date
Monthly or Toxicity	First day of month – last day of month	28th day of following month
Quarterly	January 1 – March 31 April 1 – June 30 July 1 – September 30 October 1 – December 31	April 28 July 28 October 28 January 28
Semiannual	January 1 – June 30 July 1 – December 31	July 28 January 28
Annual	January 1 – December 31	January 28

DMRs shall be submitted for each required monitoring period including months of no discharge.

The permittee shall make copies of the attached DMR form(s) and shall submit the completed DMR form(s) to the Department at the address specified below:

Florida Department of Environmental Protection
Wastewater Compliance Evaluation Section, Mail Station 3551
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

3. Unless specified otherwise in this permit, all reports and notifications required by this permit, including twenty-four hour notifications, shall be submitted to or reported to the Southeast District Office at the address specified below:

   Southeast District Office
   400 N. Congress Ave., Suite 200
   West Palm Beach, FL33416

   Phone Number – (561) 681-6600
   FAX Number - (561) 681-6766 (All FAX copies shall be followed by original copies.)

4. All reports and other information shall be signed in accordance with requirements of Rule 62-620.305, F.A.C.

5. Total Residual oxidants (TRO) means the value obtained using the amperometric titration method for total residual chlorine, or the Hach model 19300 or equivalent). Testing for TRO by titration shall be conducted according to either the low-level amperometric method, or the DPD calorimetric method as specified in section 4500-Cl E. or 4500 Cl G., respectively, Standard Methods for the examination of Water and Waste water, 18th Edition (or most current edition).

6. The permittee shall provide safe access points for obtaining representative samples which are required by this permit.

7. If there is no discharge from the facility on a day scheduled for sampling, the sample shall be collected on the day of the next discharge.

8. There shall be no discharge of polychlorinated biphenyl compounds.

9. Bypasses subject to General conditions VIII.20 and VIII.22 shall be monitored or estimated daily, or as approved by the Department for flow and other parameters required for the specific outfall which is bypassed. Monitoring results shall be reported to the Department.

10. There shall be no discharge of floating solids or visible foam in other than trace amounts and no discharge of a visible oil sheen at any time in accordance with Rules 62-302.500(1)(a) and 62-302.530(50)(b), F.A.C. Any such discharges to water of the State shall be reported to the Department when submitting DMRs.

11. Discharge of any product registered under the Federal Insecticide, Fungicide, and Rodenticide Act to any waste stream which ultimately may be released to waters of the State is prohibited unless specifically authorized elsewhere in this permit. This requirement is not applicable to products used for lawn and agricultural purposes or to the use of herbicides if used in accordance with labeled instructions and any applicable State permit.

    The company shall notify the Department in writing no later than six (6) months prior to instituting use of any biocide or chemical used in the cooling systems or any other portion of the treatment system which may be toxic to aquatic life. Such notification shall include:

    a. Name and general composition of biocide or chemical
    b. Frequencies of use
    c. Quantities to be used
    d. Proposed effluent concentrations
    e. Acute and/or chronic toxicity data (laboratory reports shall be prepared according to Section 12 of EPA document no. EPA/600/4-90/027 entitled, Methods for Measuring the Acute Toxicity of Effluents and Receiving Waters for Freshwater and Marine Organisms, or most current addition.)
    f. Product data sheet
    g. Product label

    The Department shall review the above information to determine if a substantial or minor permit revision is necessary. Discharge associated with the use of such biocide or chemical except Chlorine or Hydrazine as authorized elsewhere in this permit is not authorized without a permit revision by the Department. Permit revisions shall be processed in accordance with the requirements of Chapter 62-620, F.A.C.

12. Discharge of any waste resulting from the combustion of toxic, hazardous, or metal cleaning wastes to any waste stream which ultimately discharges to waters of the State is prohibited, unless specifically authorized elsewhere in this permit.

13. The permittee shall continue compliance with the facility's Manatee Protection Plan approved by the Department on December 21, 2000.

14. The permittee is authorized to discharge storm water from diked petroleum storage or handling areas, provided the following conditions are met:

    Such discharges shall be limited and monitored by permittee as specified below:

    1. The facility shall have a valid Spill Prevention Control and Countermeasure Plan (SPCC) Plan pursuant to 40 CFR Part 112.

    2. In draining the diked area, a portable oil skimmer or similar device or absorbent material shall be used to remove oil and grease (as indicated by the presence of a sheen) immediately prior to draining.

    3. Monitoring records shall be maintained in the form of a log and shall contain the following information, as minimum:

        a. Date and time of discharge;
        b. Estimated volume of discharge;
        c. Initials of person making visual inspection and authorizing discharge; and
        d. observed conditions of storm water discharged.

    4. There shall be no discharge of floating solids or visible foam in other than trace amounts and no discharge of visible oil sheen at any time.

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II. Industrial Sludge Management Requirements

1. The sediments and sludge excavated from the settling basins and percolation basins must be properly stored onsite until they are disposed in accordance with requirements in Chapter 62-701, F.A.C., and other applicable state and Federal requirements.

III. Ground Water Monitoring Requirements

A. Construction Requirements

1. This section is not applicable to this facility.

B. Operational Requirements

1. During the period of operation authorized by this permit, the permittee shall sample ground water in accordance with this permit and the approved ground water monitoring plan prepared under Rule 62-522.600, F.A.C.

2. The following monitoring wells shall be sampled for Well Group For: percolation pond, Land Application System R-001, R-002 and R-003:

Monitoring Well ID	Alternate Well Name and/or Description of Monitoring Location	Depth (Feet)	Aquifer Monitored	New or Existing
MWB-01	RI-MW-1 (previous intermediate well); approximately 20 feet east of the center of the eastern ends of the Solids Settling Basins.	22.25	Surficial	Existing
MWI-01	OB-5R (previous background well; relocation of previous OB-5); approximately 150 feet west of the center of the western ends of the Solids Settling Basins.	15	Surficial	Existing
MWC-01	OB-6; approximately 80 feet south of the center of the southern boundary for the south Solids Settling Basin SSB-2.	19.25	Surficial	Existing

MWB = Background; MWI = Intermediate; MWC = Compliance, MWP = Piezometer

3. The monitor wells specified in Condition III.B.2 shall be sampled for the parameters listed below:

Parameter Name	Compliance Well Limit	Units	Sample Type	Monitoring Frequency
Water Level Relative to MSL	Report	FEET	Measured	Quarterly
Solids, Total Dissolved (TDS)	Report	MG/L	Grab	Quarterly
PH	Report	SU	In-situ	Quarterly
Chloride (as Cl)				
Sulfate, Total				
Iron, Total Recoverable				
Sodium, Total Recoverable	160	MG/L	Grab	Quarterly
Arsenic, Total Recoverable	0.05	MG/L	Grab	Semiannually
Chromium, Total Recoverable	0.1	MG/L	Grab	Semiannually
Copper, Total Recoverable	Report	MG/L	Grab	Semiannually

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Parameter Name	Compliance Well Limit	Units	Sample Type	Monitoring Frequency
Manganese, Total Recoverable	Report	MG/L	Grab	Semiannually
Nickel, Total Recoverable	0.1	MG/L	Grab	Semiannually
Silver, Total Recoverable	Report	MG/L	Grab	Semiannually
Zinc, Total Recoverable	Report	MG/L	Grab	Semiannually
Oil and Grease	Report	MG/L	Grab	Semiannually

4. A zone of discharge is established for R-001, R-002 and R-003, more specifically described as follows: The zone of discharge extends horizontally along the ground surface to the property line, and vertically to the base of the surficial aquifer.
5. The permittee's discharge to ground water shall not cause a violation of water quality standards for ground waters at the boundary of the zone of discharge in accordance with Rules 62-520.400 and 62-520.420, F.A.C.
6. The permittee's discharge to ground water shall not cause a violation of the minimum criteria for ground water specified in Rule 62-520.400, F.A.C., within the zone of discharge.
7. If the concentration for any constituent listed in Permit Condition III.B.3, in the natural background quality of the ground water is greater than the stated maximum, or in the case of pH is also less than the minimum, the representative natural background quality shall be the prevailing standard.
8. Water levels shall be recorded prior to evacuating the well for sample collection. Elevation references shall include the top of the well casing and land surface at each well site (NGVD allowable) at a precision of plus or minus 0.1 feet.
9. Ground water monitoring wells shall be purged prior to sampling to obtain a representative sample.
10. Analyses shall be conducted on unfiltered samples, unless filtered samples have been approved in writing by the Department as being more representative of ground water conditions.
11. If a monitoring well becomes damaged or cannot be sampled for an appropriate reason, the permittee shall notify the Department immediately and a written report shall follow within seven days detailing the circumstances and remedial measures taken or proposed. Repair or replacement of monitoring wells shall require approval in writing by the Department.
12. All piezometers and wells not part of the approved ground water monitoring plan are to be plugged and abandoned in accordance with Rule 62-532.500(4), F.A.C., unless there is intent for their future use.
13. The permittee shall provide verbal notice to the Department as soon as practical after discovery of a sinkhole within an area for the management or application of wastewater or sludge. The permittee shall immediately implement measures appropriate to control the entry of contaminants, and shall detail these measures to the Department in a written report within 7 days of the sinkhole discovery.
14. Ground water monitoring test results shall be submitted on Part D of DEP Form 62-620.910(10) (attached) and shall be submitted to the address specified in I.E.3. Results shall be submitted with the DMR for each month listed in the following schedule.

SAMPLE PERIOD	REPORT DUE DATE
January – March	April 28
April – June	July 28
July – September	October 28
October – December	January 28

IV. Other Land Application Requirements

The bottoms for the settling basins and percolation basins shall be cleaned out periodically, or when necessary, to remove the excess buildup of sediments, and to ensure continuous percolation capability for the percolation basins. Materials removed from the basins shall be managed as required in item II.of this permit. Routine weed control and regular maintenance of basin embankments and access areas are required. The permittee shall inspect the condition of the impermeable liners for the lined settling basins and the percolation basins with lined side slopes. Any liners that display signs of significant deterioration or evidence of leakage or instability, shall be replaced immediately.

V. Operation and Maintenance Requirements

<u>A. Operation of Treatment and Disposal Facilities</u>

1. The permittee shall ensure that the operation of this facility is as described in the application and supporting documents.
2. The operation of the pollution control facilities described in this permit shall be under the supervision of a person who is qualified by formal training and/or practical experience in the field of water pollution control.

<u>B. Record keeping Requirements:</u>

1. The permittee shall maintain the following records on the site of the permitted facility and make them available for inspection:
   a. Records of all compliance monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, including, if applicable, a copy of the laboratory certification showing the certification number of the laboratory, for at least three years from the date the sample or measurement was taken;
   b. Copies of all reports, other than those required in items a. and f. of this section, required by the permit for at least three years from the date the report was prepared, unless otherwise specified by Department rule;
   c. Records of all data, including reports and documents used to complete the application for the permit for at least three years from the date the application was filed, unless otherwise specified by Department rule;
   d. A copy of the current permit;
   e. A copy of any required record drawings;
   f. Copies of the logs and schedules showing plant operations and equipment maintenance for three years from the date on the logs or schedule.

VI. Schedules

1. The permittee shall achieve compliance with the other conditions of this permit as follows:

Action Item and Operational level attained	Scheduled Completion and Issuance Date of permit
Continue implementing existing BMP3 plan pursuant to section VII.D of this permit.	

2. No later than 14 calendar days following a date identified in the above schedule(s) of compliance, the permittee shall submit either a report of progress or, in the case of specific actions being required by an identified date, a written notice of compliance or noncompliance. In the latter case, the notice shall include the cause of noncompliance, any remedial actions taken, and the probability of meeting the next scheduled requirement.

   Within 180 days following permit issuance, the Permittee shall provide to the Department existing or new biological or water quality information related to thermal discharges.

4. Within 180 days following permit issuance, the permit shall initiate a chlorine optimization study for its cooling water chlorination and dechlorination system. The chlorine minimization study shall be completed within two years after it is initiated. The permittee shall provide the Department status updates until the study is complete. The chlorination optimization study shall incorporate the following milestones:

   a. Notify Department of Initiation of Chlorination Optimization Study ....Within 2 Weeks of Initiation

   b. Submit Summary Report of Phase I of Chlorination Optimization Study .... Upon Completion

   c. Submit Quarterly Reports of Phase II of Chlorination Optimization Study .... Every three months until completion

   d. Notify Department of Completion of Chlorination Optimization Study .... Upon Completion

   e. Submit Final Chlorination Optimization Study Report ....Upon completion but within two years following permit issuance.

   f. Incorporate Chlorination Optimization Strategy into BMP3 ....Upon Completion of Chlorination Optimization Study

VII. Other Specific Conditions

A. Specific Conditions Applicable to All Permits

1. Drawings, plans, documents or specifications submitted by the permittee, not attached hereto, but retained on file at the Unknown District Office, are made a part hereof.

2. Where required by Chapter 471 (P.E.) or Chapter 492 (P.G.) Florida Statutes, applicable portions of reports to be submitted under this permit, shall be signed and sealed by the professional(s) who prepared them.

3. This permit satisfies Industrial Wastewater program permitting requirements only and does not authorize operation of this facility prior to obtaining any other permits required by local, state or federal agencies.

B. Specific Conditions Related to Construction

1. This section is not applicable to this facility.

C. Duty to Reapply

1. The permittee shall submit an application to renew this permit at least 180 days before the expiration date of this permit.

2. The permittee shall apply for renewal of this permit on the appropriate form listed in Rule 62-620.910, F.A.C., and in the manner established in Chapter 62-620, F.A.C., and the Department of Environmental Protection Guide to Wastewater Permitting including submittal of the appropriate processing fee set forth in Rule 62-4.050, F.A.C.

3. An application filed in accordance with subsections 1. and 2. of this part shall be considered timely and sufficient. When an application for renewal of a permit is timely and sufficient, the existing permit shall not expire until the Department has taken final action on the application for renewal or until the last day for seeking judicial review of the agency order or a later date fixed by order of the reviewing court.

4. The late submittal of a renewal application shall be considered timely and sufficient for the purpose of extending the effectiveness of the expiring permit only if it is submitted and made complete before the expiration date.

D. Specific Conditions Related to Best Management Practices/Pollution Prevention Conditions

1. **General Conditions**

In accordance with Section 304(e) and 402(a)(2) of the Clean Water Act (CWA) as amended, 33 U.S.C. §§ 1251 et seq., and the Pollution Prevention Act of 1990, 42 U.S.C. §§ 13101-13109, the permittee must develop and implement a plan for utilizing practices incorporating pollution prevention measures. References to be considered in developing the plan are "Criteria and Standards for Best Management Practices Authorized Under Section 304(e) of the Act," found at 40 CFR 122.44 Subpart K and the Waste Minimization Opportunity Assessment Manual, EPA/625/7-88/003.

a. *Definitions*

(1) The term "pollutants" refers to conventional, non-conventional and toxic pollutants.

(2) Conventional pollutants are: biochemical oxygen demand (BOD), suspended solids, pH, fecal coliform bacteria and oil & grease.

(3) Non-conventional pollutants are those which are not defined as conventional or toxic.

(4) Toxic pollutants include, but are not limited to: (a) any toxic substance listed in Section 307(a)(1) of the CWA, any hazardous substance listed in Section 311 of the CWA, or chemical listed in Section 313(c) of the Superfund Amendments and Reauthorization Act of 1986; and (b) any substance (that is not also a conventional or non-conventional pollutant except ammonia) for which EPA has published an acute or chronic toxicity criterion.

(5) "*Pollution prevention*" and "*waste minimization*" refer to the first two categories of EPA's preferred hazardous waste management strategy: first, source reduction and then, recycling.

(6) "Recycle/Reuse" is defined as the minimization of waste generation by recovering and reprocessing usable products that might otherwise become waste; or the reuse or reprocessing of usable waste products in place of the original stock, or for other purposes such as material recovery, material regeneration or energy production.

(7) "Source reduction" means any practice which: (a) reduces the amount of any pollutant entering a waste stream or otherwise released into the environment (including fugitive emissions) prior to recycling, treatment or disposal; and (b) reduces the hazards to public health and the environment associated with the release of such pollutant. The term includes equipment or technology modifications, process or procedure modifications, reformulation or redesign of products, substitution of raw materials, and

improvements in housekeeping, maintenance, training, or inventory control. It does not include any practice which alters the physical, chemical, or biological characteristics or the volume of a pollutant through a process or activity which itself is not integral to, or previously considered necessary for, the production of a product or the providing of a service.

(8) "BMP3" means a Best Management Plan incorporating the requirements of 40 CFR § 122.44, Subpart K, plus pollution prevention techniques associated with a Waste Minimization Assessment.

(9) "Waste Minimization Assessment" means a systematic planned procedure with the objective of identifying ways to reduce or eliminate waste.

2. **Best Management Practices/Pollution Prevention Plan**

The permittee shall develop and implement a BMP3 plan for the facility which is the source of wastewater and storm water discharges covered by this permit. The plan shall be directed toward reducing those pollutants of concern which discharge to surface waters and shall be prepared in accordance with good engineering and good housekeeping practices. For the purposes of this permit, pollutants of concern shall be limited to toxic pollutants, as defined above, known to the discharger. The plan shall address all activities which could or do contribute these pollutants to the surface water discharge, including process, treatment, and ancillary activities.

a. Signatory Authority & Management Responsibilities

The BMP3 plan shall be signed in accordance with Item VII.A.2. and shall be reviewed by the plant engineering staff and plant manager. A copy of the plan shall be retained at the facility and shall be made available to the permit issuing authority upon request.

The BMP3 plan shall contain a written statement from corporate or plant management indicating management's commitment to the goals of the BMP3 program. Such statements shall be publicized or made known to all facility employees. Management shall also provide training for the individuals responsible for implementing the BMP3 plan.

b. BMP3 Plan Requirements

(1) Name & description of facility, a map illustrating the location of the facility & adjacent receiving waters, and other maps, plot plans or drawings, as necessary;

(2) Overall objectives (both short-term and long-term) and scope of the plan, specific reduction goals for pollutants, anticipated dates of achievement of reduction, and a description of means for achieving each reduction goal;

(3) A description of procedures relative to spill prevention, control & countermeasures and a description of measures employed to prevent storm water contamination;

(4) A description of practices involving preventive maintenance, housekeeping, recordkeeping, inspections, and plant security; and

(5) The description of a waste minimization assessment performed in accordance with the conditions outlined in condition c below, results of the assessment, and a schedule for implementation of specific waste reduction practices.

c. Waste Minimization Assessment

A waste minimization assessment (WMA) shall be conducted for this facility to determine actions that could be taken to reduce waste loadings and chemical losses to all wastewater and/or storm water streams as described in Part VII.D.2 of this permit. It shall address both short-term and long-term opportunities for minimizing waste generation at this facility, utilizing at a minimum, applicable criteria selected from Part VII.D.2: Required Components of a Waste Minimization Assessment, particularly for high volume and/or high toxicity components of wastewater and storm water streams. Initially, the WMA should focus primarily on actions that could be implemented quickly, thereby realizing tangible benefits to surface water quality. Long term goals and actions pertaining to waste reduction shall include investigation of the feasibility of eliminating toxic chemical use, instituting process changes, raw material replacements, etc.

Implementation of Results: The permittee shall implement each waste reduction practice recommended by the WMA as soon as practicable. Any waste reduction practices which are identified but will not be implemented shall be described in the required Pollution Prevention plan summary or progress/update reports, along with the factors inhibiting their adoption. Any waste reduction practices which cannot be implemented immediately shall be described in the Pollution Prevention plan.

Timeframe: The permit issuing authority does not herein establish a time limit for completion of the WMA; the study may be conducted throughout the term of this permit. However, a suggested target completion date is six months after the effective date of the permit, so that the WMA results and recommended waste reduction practices may be incorporated into the BMP3 plan. Continual studies toward minimizing waste are encouraged.

Practices which reduce pollutant loading in wastewater or storm water discharges with a consequent increase in solid hazardous waste generation, decrease in air quality, or adverse affect to groundwater shall not be considered waste reduction for the purposes of this assessment.

d. Best Management Practices & Pollution Prevention Committee Recommended:

A Best Management Practices Committee (Committee) should be established to direct or assist in the implementation of the BMP3 plan. The Committee should be comprised of individuals within the plant organization who are responsible for developing the BMP3 plan and assisting the plant manager in its implementation, monitoring of success, and revision. The activities and responsibilities of the Committee should address all aspects of the facility's BMP3 plan. The scope of responsibilities of the Committee should be described in the plan.

e. Employee Training

Employee training programs shall inform personnel at all levels of responsibility of the components & goals of the BMP3 plan and shall describe employee responsibilities for implementing the plan. Training shall address topics such as good housekeeping, materials management, record keeping & reporting, spill prevention & response, as well as specific waste reduction practices to be employed. Training should also disclose how individual employees may contribute suggestions concerning the BMP3 plan or suggestions regarding Pollution Prevention. The plan shall identify periodic dates for such training.

f. Plan Development & Implementation

The BMP3 plan shall be developed and implemented 6 months after the effective date of this permit, unless any later dates are specified in this permit. Any portion of the WMA which is ongoing at the time of development or implementation shall be described in the plan. Any waste reduction practice which is recommended for implementation over a period of time shall be identified in the plan, including a schedule for its implementation.

g. Submission of Plan Summary & Progress/Update Reports

(1) Plan Summary: Not later than 2 years after the effective date of the permit, a summary of the BMP3 plan shall be developed and maintained at the facility and made available to the permit issuing authority upon request. The summary should include the following: a brief description of the plan, its implementation process, schedules for implementing identified waste reduction practices, and a list of all waste reduction practices being employed at the facility. The results of waste minimization assessment studies already completed as well as any scheduled or ongoing WMA studies shall be discussed.

(2) Progress/Update Reports: Annually thereafter for the duration of the permit progress/update reports documenting implementation of the plan shall be maintained at the facility and made available to the permit issuing authority upon request. The reports shall discuss whether or not implementation schedules were met and revise any schedules, as necessary. The plan shall also be updated as necessary and the attainment or progress made toward specific pollutant reduction targets documented. Results of any ongoing WMA studies as well as any additional schedules for implementation of waste reduction practices shall be included.

(3) A timetable for the various plan requirements follows:

Timetable for BMP3 Plan Requirements:

REQUIREMENT	TIME FROM EFFECTIVE DATE OF THIS PERMIT
Complete WMA	6 months
Develop & Implement Plan	6 months
Develop Plan Summary	2 Years
Progress/Update Reports	3 years, and then annually thereafter

The permittee shall maintain the plan and subsequent reports at the facility and shall make the plan available to the Department upon request.

h. Plan Review & Modification

If following review by the Department, the BMP3 plan is determined insufficient, the permittee will be notified that the BMP3 plan does not meet one or more of the minimum requirements of this Part. Upon such notification from the Department, the permittee shall amend the plan and shall submit to the Department a written certification that the requested changes have been made. Unless otherwise provided by the Department, the permittee shall have 30 days after such notification to make the changes necessary.

The permittee shall modify the BMP3 plan whenever there is a change in design, construction, operation, or maintenance, which has a significant effect on the potential for the discharge of pollutants to waters of the State or if the plan proves to be ineffective in achieving the general objectives of reducing pollutants in wastewater or storm water discharges. Modifications to the plan may be reviewed by the Department in the same manner as described above.

5. Required Components Of A Waste Minimization Assessment

a. Plant Water Balance

The WMA shall include an overall plant water balance, as well as internal water balances, as necessary. This information shall be used to determine any opportunities for water conservation or reuse/recycling and to determine if and where leakages might occur.

b. Material and Risk Assessment

A materials & risk assessment shall be developed and shall include the following:

(1) Identification of the types & quantities of materials used or manufactured (including by-products produced) at the facility;

(2) Identification of the location & types of materials management activities which occur at the facility;

(3) An evaluation of the following aspects of materials compatibility: containment & storage practices for chemicals, container compatibility, chemical mixing procedures; potential mixing or compatibility problems; and specific prohibitions regarding mixing of chemicals;

(4) Technical information on human health and ecological effects of toxic or hazardous chemicals presently used or manufactured (including by-products produced) or planned for future use or production; and

(5) Analyses of chemical use & waste generation, including overall plant material balances and as necessary, internal process balances, for all pollutants. (When actual measurements of the quantity of a chemical entering a wastewater or storm water stream are not readily available, reasonable estimates should be made based on best engineering judgment.) The analyses shall address reasons for using particular chemicals, and measures or estimates of the actual and potential chemical discharges via wastewater, wastewater sludge, storm water, air, solid waste or hazardous waste media.

c. Pollutant Reduction Methods

The WMA shall include, at a minimum, the following means of reducing pollutant discharges in wastewater streams or of otherwise minimizing wastes:

(1) Process related source reduction measures, including any or all of the following, as appropriate:

(a) production process changes;
(b) improved process controls;
(c) reduction of off-spec materials;
(d) reduction in use of toxic or hazardous materials;
(e) chemical modifications and/or material purification;
(f) chemical substitution employing non-toxic or less toxic alternatives; and
(g) equipment upgrades or modifications or changes in equipment use.

(2) housekeeping/operational changes, including waste stream segregation, inventory control, spill & leak prevention, equipment maintenance; and employee training in areas of pollution prevention, good housekeeping, and spill prevention & response;

(3) in-process recycling, on-site recycling and/or off-site recycling of materials;

(4) following all source reduction & recycling practices, wastewater treatment process changes, including the use of new or improved treatment methods, such that treatment by-products are less toxic to aquatic or human life; and

(5) other means as agreed upon by the permit issuing authority and the permittee.

d. Storm Water Evaluation

For storm water discharges and instances where storm water enters the wastewater treatment/disposal system or is otherwise commingled with wastewater, the WMA shall evaluate the following potential sources of storm water contamination, at a minimum:

(1) loading, unloading and transfer areas for dry bulk materials or liquids;

(2) outdoor storage of raw materials or products;

(3) outdoor manufacturing or processing activities;

(4) dust or particulate generating processes; and

(5) on-site waste and/or sludge disposal practices.

The likelihood of storm water contact in these areas and the potential for spills from these areas shall be considered in the evaluation. The history of significant leaks or spills of toxic or hazardous pollutants shall also be considered. Recommendations for changes to current practices which would reduce the potential for storm water contamination from these areas shall be made, as necessary.

E. Specific Conditions Related to Existing Manufacturing, Commercial, Mining, and Silviculture Wastewater Facilities or Activities

1. Existing manufacturing, commercial, mining, and silvicultural wastewater facilities or activities that discharge into surface waters shall notify the Department as soon as they know or have reason to believe:

a. That any activity has occurred or will occur which would result in the discharge, on a routine or frequent basis, of any toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following levels

(1) One hundred micrograms per liter,
(2) Two hundred micrograms per liter for acrolein and acrylonitrile; five hundred micrograms per liter for 2,4-dinitrophenol and for 2-methyl-4,6-dinitrophenol; and one milligram per liter for antimony, or
(3) Five times the maximum concentration value reported for that pollutant in the permit application.

b. That any activity has occurred or will occur which would result in any discharge, on a non-routine or infrequent basis, of a toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following levels
(1) Five hundred micrograms per liter,
(2) One milligram per liter for antimony, or

(3) Ten times the maximum concentration value reported for that pollutant in the permit

F. Reopener Clause

1. The permit shall be revised, or alternatively, revoked and reissued in accordance with the provisions contained in Rules 62-620.325 and 62-620.345 F.A.C., if applicable, or to comply with any applicable effluent standard or

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limitation issued or approved under Sections 301(b)(2)(C) and (D), 304(b)(2) and 307(a)(2) of the Clean Water Act (the Act), as amended, if the effluent standards, limitations, or water quality standards so issued or approved:

a. Contains different conditions or is otherwise more stringent than any condition in the permit/or;

b. Controls any pollutant not addressed in the permit.

The permit as revised or reissued under this paragraph shall contain any other requirements then applicable.

2. The permit may be reopened to adjust effluent limitations or monitoring requirements should future Water Quality Based Effluent Limitation determinations, water quality studies, DEP approved changes in water quality standards, or other information show a need for a different limitation or monitoring requirement.

3. The Department may develop a Total Maximum Daily Load (TMDL) during the life of the permit. Once a TMDL has been established and adopted by rule, the Department shall revise this permit to incorporate the final findings of the TMDL.

VIII. General Conditions

1. The terms, conditions, requirements, limitations and restrictions set forth in this permit are binding and enforceable pursuant to Chapter 403, Florida Statutes. Any permit noncompliance constitutes a violation of Chapter 403, Florida Statutes, and is grounds for enforcement action, permit termination, permit revocation and reissuance, or permit revision. *[62-620.610(1), F.A.C]*

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviations from the approved drawings, exhibits, specifications or conditions of this permit constitute grounds for revocation and enforcement action by the Department. *[62-620.610(2), F.A.C.]*

3. As provided in Subsection 403.087(6), F.S., the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor authorize any infringements of federal, state, or local laws or regulations. This permit is not a waiver of or approval of any other Department permit or authorization that may be required for other aspects of the total project which are not addressed in this permit. *[62-620.610(3), F.A.C.]*

4. This permit conveys no title to land or water, does not constitute state recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title. *[62-620.610(4), F.A.C.]*

5. This permit does not relieve the permittee from liability and penalties for harm or injury to human health or welfare, animal or plant life, or property caused by the construction or operation of this permitted source; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department. The permittee shall take all reasonable steps to minimize or prevent any discharge, reuse of reclaimed water, or residuals use or disposal in violation of this permit which has a reasonable likelihood of adversely affecting human health or the environment. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. *[62-620.610(5), F.A.C.]*

6. If the permittee wishes to continue an activity regulated by this permit after its expiration date, the permittee shall apply for and obtain a new permit. *[62-620.610(6), F.A.C.]*

7. The permittee shall at all times properly operate and maintain the facility and systems of treatment and control, and related appurtenances, that are installed and used by the permittee to achieve compliance with the conditions of this permit. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to maintain or achieve compliance with the conditions of the permit. *[62-620.610(7), F.A.C.]*

8. This permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit revision, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance does not stay any permit condition. *[62-620.610(8), F.A.C.]*

9. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, including an authorized representative of the Department and authorized EPA personnel, when applicable, upon presentation of credentials or other documents as may be required by law, and at reasonable times, depending upon the nature of the concern being investigated, to

   a. Enter upon the permittee's premises where a regulated facility, system, or activity is located or conducted, or where records shall be kept under the conditions of this permit;

   b. Have access to and copy any records that shall be kept under the conditions of this permit;

   c. Inspect the facilities, equipment, practices, or operations regulated or required under this permit; and

   d. Sample or monitor any substances or parameters at any location necessary to assure compliance with this permit or Department rules.

   [62-620.610(9), F.A.C.]

10. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data, and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except as such use is proscribed by Section 403.111, Florida Statutes, or Rule 62-620.302, F.A.C. Such evidence shall only be used to the extent that it is consistent with the Florida Rules of Civil Procedure and applicable evidentiary rules. [62-*620.610(10), F.A.C.]*

11. When requested by the Department, the permittee shall within a reasonable time provide any information required by law which is needed to determine whether there is cause for revising, revoking and reissuing, or terminating this permit, or to determine compliance with the permit. The permittee shall also provide to the Department upon request copies of records required by this permit to be kept. If the permittee becomes aware of relevant facts that were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be promptly submitted or corrections promptly reported to the Department. *[62-620.610(11), F.A.C.]*

12. Unless specifically stated otherwise in Department rules, the permittee, in accepting this permit, agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance; provided however, the permittee does not waive any other rights granted by Florida Statutes or Department rules. A reasonable time for compliance with a new or amended surface water quality standard, other than those standards addressed in Rule 62-302.500, F.A.C., shall include a reasonable time to obtain or be denied a mixing zone for the new or amended standard. *[62-620.610(12), F.A.C.]*

13. The permittee, in accepting this permit, agrees to pay the applicable regulatory program and surveillance fee in accordance with Rule 62-4.052, F.A.C. *[62-620.610(13), F.A.C.]*

14. This permit is transferable only upon Department approval in accordance with Rule 62-620.340, F.A.C. The permittee shall be liable for any noncompliance of the permitted activity until the transfer is approved by the Department. *[62-620.610(14), F.A.C.]*

15. The permittee shall give the Department written notice at least 60 days before inactivation or abandonment of a wastewater facility and shall specify what steps will be taken to safeguard public health and safety during and following inactivation or abandonment. *[62-620.610(15), F.A.C.]*

16. The permittee shall apply for a revision to the Department permit in accordance with Rules 62-620.300 and the Department of Environmental Protection Guide to Wastewater Permitting at least 90 days before construction of any planned substantial modifications to the permitted facility is to commence or with Rule 62-620.325(2) for minor modifications to the permitted facility. A revised permit shall be obtained before construction begins except as provided in Rule 62-620.300, F.A.C. *[62-620.610(16), F.A.C.]*

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17. The permittee shall give advance notice to the Department of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements. The permittee shall be responsible for any and all damages which may result from the changes and may be subject to enforcement action by the Department for penalties or revocation of this permit. The notice shall include the following information:

    a. A description of the anticipated noncompliance;

    b. The period of the anticipated noncompliance, including dates and times; and

    c. Steps being taken to prevent future occurrence of the noncompliance.

    [62-620.610(17), F.A.C.]

18. Sampling and monitoring data shall be collected and analyzed in accordance with Rule 62-4.246, Chapter 62-160 and 62-601, F.A.C. and 40CFR 136, as appropriate.

    a. Monitoring results shall be reported at the intervals specified elsewhere in this permit and shall be reported on a Discharge Monitoring Report (DMR), DEP Form 62-620.910(10).

    b. If the permittee monitors any contaminant more frequently than required by the permit, using Department approved test procedures, the results of this monitoring shall be included in the calculation and reporting of the data submitted in the DMR.

    c. Calculations for all limitations, which require averaging of measurements shall use an arithmetic mean unless otherwise specified in this permit.

    d. Any laboratory test required by this permit shall be performed by a laboratory that has been certified by the Department of Health (DOH) under Chapter 64E-1, F.A.C., where such certification is required by Rule 62-160.300, F.A.C. The laboratory must be certified for any specific method and analyte combination that is used to comply with this permit. For domestic wastewater facilities, the on-site test procedures specified in Rule 62-160.300(4), F.A.C., shall be performed by a laboratory certified test for those parameters or under the direction of an operator certified under Chapter 62-602, F.A.C.

    e. Field activities including on-site tests and sample collection, whether performed by a laboratory or a certified operator, must follow the applicable procedures described in DEP-SOP-001/01 (January 2002). Alternate field procedures and laboratory methods may be used where they have been approved according to the requirements of Rules 62-160.220, 62-160.330, and 62-160.600, F.A.C.

19. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule detailed elsewhere in this permit shall be submitted no later than 14 days following each schedule date. *[62-620.610(19), F.A.C.]*

20. The permittee shall report to the Department's Southeast District Office any noncompliance which may endanger health or the environment. Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided within five days of the time the permittee becomes aware of the circumstances. The written submission shall contain a description of the noncompliance and its cause; the period of noncompliance including exact dates and time, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

    a. The following shall be included as information which must be reported within 24 hours under this condition:

        1. Any unanticipated bypass which causes any reclaimed water or effluent to exceed any permit limitation or results in an unpermitted discharge,

        2. Any upset which causes any reclaimed water or the effluent to exceed any limitation in the permit,

        3. Violation of a maximum daily discharge limitation for any of the pollutants specifically listed in the permit for such notice, and

        4. Any unauthorized discharge to surface or ground waters.

b. Oral reports as required by this subsection shall be provided as follows:

1. For unauthorized releases or spills of untreated or treated wastewater reported pursuant to subparagraph a.4 that are in excess of 1,000 gallons per incident, or where information indicates that public health or the environment will be endangered, oral reports shall be provided to the Department by calling the STATE WARNING POINT TOLL FREE NUMBER (800) 320-0519, as soon as practical, but no later than 24 hours from the time the permittee becomes aware of the discharge. The permittee, to the extent known, shall provide the following information to the State Warning Point:

(a) Name, address, and telephone number of person reporting;

(b) Name, address, and telephone number of permittee or responsible person for the discharge;

(c) Date and time of the discharge and status of discharge (ongoing or ceased);

(d) Characteristics of the wastewater spilled or released (untreated or treated, industrial or domestic wastewater);

(e) Estimated amount of the discharge;

(f) Location or address of the discharge;

(g) Source and cause of the discharge;

(h) Whether the discharge was contained on-site, and cleanup actions taken to date;

(i) Description of area affected by the discharge, including name of water body affected, if any; and

(j) Other persons or agencies contacted.

2. Oral reports, not otherwise required to be provided pursuant to subparagraph b.1 above, shall be provided to Department's Southeast District Office within 24 hours from the time the permittee becomes aware of the circumstances.

c. If the oral report has been received within 24 hours, the noncompliance has been corrected, and the noncompliance did not endanger health or the environment, the Department's Southeast District Office shall waive the written report.

[62-620.610(20), F.A.C.]

21. The permittee shall report all instances of noncompliance not reported under Conditions VIII.18 and 19 of this permit at the time monitoring reports are submitted. This report shall contain the same information required by Condition VIII.20 of this permit. *[62-620.610(21), F.A.C.]*

22. Bypass Provisions:

a. Bypass is prohibited, and the Department may take enforcement action against a permittee for bypass, unless the permittee affirmatively demonstrates that:

1. Bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

2. There were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if adequate back-up equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass which occurred during normal periods of equipment downtime or preventative maintenance; and

3. The permittee submitted notices as required under Condition VIII.22.b of this permit.

b. If the permittee knows in advance of the need for a bypass, it shall submit prior notice to the Department, if possible at least 10 days before the date of the bypass. The permittee shall submit notice of an unanticipated bypass within 24 hours of learning about the bypass as required in Condition VIII.20 of this permit. A notice shall include a description of the bypass and its cause; the period of the bypass, including exact dates and

PERMITTEE:
Florida Power & Light Company
200-300 Broadway Company
Riviera Beach, Florida 33404

PERMIT NUMBER: FL0001546
Issuance date: February 10, 2004
Expiration date: February 09, 2009

times; if the bypass has not been corrected, the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence of the bypass.

c. The Department shall approve an anticipated bypass, after considering its adverse effect, if the permittee demonstrates that it will meet the three conditions listed in Condition VIII.22 a.(1) through (3) of this permit.

d. A permittee may allow any bypass to occur which does not cause reclaimed water or effluent limitations to be exceeded if it is for essential maintenance to assure efficient operation. These bypasses are not subject to the provision of Condition VIII.22.a through c. of this permit.

[62-620.610(22), F.A.C.]

23. Upset Provisions:

a. A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed contemporaneous operating logs, or other relevant evidence that:

1. An upset occurred and that the permittee can identify the cause(s) of the upset;
2. The permitted facility was at the time being properly operated;
3. The permittee submitted notice of the upset as required in Condition VIII.20 of this permit; and
4. The permittee complied with any remedial measures required under Condition VIII.5 of this permit.

b. In any enforcement proceeding, the permittee seeking to establish the occurrence of an upset has the burden of proof.

c. Before an enforcement proceeding is instituted, no representation made during the Department review of a claim that noncompliance was caused by an upset is final agency action subject to judicial review.

[62-620.610(23), F.A.C.]

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Mimi Drew

Mimi Drew
Director
Division of Water Resource Management

2600 Blair Stone Road
Tallahassee, FL32399-2400
(850) 245-8336

Department of Environmental Protection

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Jeb Bush
Governor

David B. Struhs
Secretary

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

In the matter of:
Approval of FPL Riviera Power Plant
Manatee Protection Plan

DEP Permit No. FL0001546
Palm Beach County

Mr. Ron Hix
FPL-5ES/JB
Florida Power & Light Company (FPL)
P. O. Box 14000
Juno Beach, FL 33408

NOTICE OF AGENCY ACTION

The Department of Environmental Protection hereby gives notice of its approval of the enclosed Manatee Protection Plan for the FPL Riviera Plant, dated August 7, 2000. The Manatee Protection Plan was completed pursuant to Specific Condition 12 of the above referenced permit.

A person whose substantial interests are affected by the Department action may petition for an administrative hearing in accordance with sections 120.569 and 120.57 of the Florida Statutes.

The petition must contain the information set forth below and must be filed (received) in the Department of Environmental Protection, Office of General Counsel, Mail Station 35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000. Petitions filed by the applicant or any of the parties listed below must be filed within twenty-one days of receipt of this notice of intent. Petitions filed by any other person must be filed within twenty-one days of publication of the public notice or within twenty-one days of receipt of this notice of intent, whichever occurs first. A petitioner must mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 of the Florida Statutes, or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the discretion of the presiding officer upon the filing of a motion in compliance with rule 28-5.207 of the Florida Administrative Code.

A petition must contain the following information:
(a) The name, address, and telephone number of each petitioner; the Department case 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 Department action;

FLORIDA PUBLIC SERVICE COMMISSION
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(c) A statement of how each petitioner's substantial interests are affected by the Department action;
(d) A statement of the material facts disputed by the petitioner, if any;
(e) A statement of facts that the petitioner contends warrant reversal or modification of the Department action;
(f) A statement of which rules or statutes the petitioner contends require reversal or modification of the Department action; and
(g) A statement of the relief sought by the petitioner, stating precisely the action that the petitioner wants the Department to take.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department final action may be different from the position taken by it in this order. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation under section 120.573 of the Florida Statutes is not available for this proceeding.

This action is final and effective on the date filed with the Clerk of the Department unless a petition is filed in accordance with the above. Upon the timely filing of a petition this order will not be effective until further order of the Department.

Any party to the order has the right to seek judicial review of the order under section 120.68 of the Florida Statutes, by the filing of a notice of appeal under rule 9.110 of the Florida Rules of Appellate Procedure with the Clerk of the Department of Environmental Protection, Office of General Counsel, Mail Station 35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000; and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate district court of appeal. The notice of appeal must be filed within 30 days from the date when the final order is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Mimi Drew

Mimi Drew
Director
Division of Water Resource Management

2600 Blair Stone Road
Tallahassee, FL 32399-2400
(850) 487-1855

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF AGENCY ACTION and all copies were mailed before the close of business on 12-21-00 to the listed persons.

FILING AND ACKNOWLEDGMENT

FILED, on this date, under section 120.52(7), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

S. Shields 12-21-00
(Clerk) (Date)

Copies furnished to:

Kipp Frohlich, FWC Tallahassee
Chairman, Board of Palm Beach County Commissioners
Jim Valade, U.S. Fish and Wildlife Service
Save the Manatee Club
Tim Powell, DEP West Palm Beach
Betsy Hewitt, DEP Office of General Counsel

Florida Power & Light – Riviera
Manatee Protection Plan
(August 7, 2000)

Purpose:

The purpose of the Manatee Protection Plan is to set forth Florida Power & Light Company's (FPL) procedures to comply with Specific Condition 12 of the facility's State Industrial Wastewater Permit Number FL0001546 that was issued on February 16, 1998. This Specific Condition reads, in part:

12. The permittee, in so far as required to comply with Tasks 25 and 251 of the U.S. Fish and Wildlife Service (USFWS) "Florida Manatee Recovery Plan," shall develop a plan and procedures addressing potential manatee impacts, ...All plans, if required, shall include an implementation schedule and address, at a minimum:

    (a) Plans to minimize disruption to warm-water outflows during the winter and response procedures in case of disruptions.

    (b) Strategy to maintain discharge temperatures that will sustain manatees during cold events.

    (c) Plan to monitor ambient and discharge temperatures.

    (d) Precautions to minimize hazards to manatees at intake and outfall areas.

    (e) Timely communication to manatee recovery program personnel of any long term changes in the availability of warm water.

Compliance with Specific Condition 12:

1. This Manatee Protection Plan will be in effect during the term of the permit. In order for the plant's warm water discharge to provide a safe, warm water refuge for the manatees and to comply with Specific Condition 12, FPL will take the following actions:

    a) In the case of an unplanned shutdown or a plant failure that will affect the warm water refuge from November 15 through March 31, when the ambient water temperature is below 61°F., the Florida Fish and Wildlife Conservation Commission (FWC) and USFWS will be notified no later than four (4) hours after the event has occurred. If an unplanned shutdown occurs that is expected to result in no thermal discharge for 24 hours or longer, regardless of ambient water temperature, the Florida Marine Research Institute should be notified.

    The following agency representatives shall be notified in the above referenced events or if any distressed manatees are observed at any time:

    FWC/Florida Marine Research Institute-Marine Mammal Pathobiology Lab:(727)-893-
2904

USFWS - Jacksonville Field Office: (904) 232-2580

The FWC, Bureau of Protected Species Management (BPSM) shall be provided a schedule of any anticipated in-water work within the discharge area or work that will affect the warm water refuge during the period of November 15 through March 31 each year. No routine in-water maintenance work shall occur in the discharge area from November 15 through March 31, unless it is considered essential by FPL and approved by BPSM prior to the start of work. If emergency in-water work is needed, the BPSM will be notified and consulted no later than two weeks following the commencement of the activity. All vessels used in the operation or associated with the activity shall be operated pursuant to the attached standard manatee construction conditions.

b) From November 15 through March 31 each year, to coincide with the time of greatest manatee abundance, if the ambient water temperature falls below 61°F., the FPL Riviera power plant shall endeavor to operate in a manner that maintains the water temperature in an adequate portion of the Unit 1 and 2 "discharge area" at or above 68°F., until such time as the ambient water temperature reaches 61°F., unless otherwise authorized by BPSM and the USFWS, or unless safety or reliability of the plant would be compromised. The main method for heating this area will be the "manatee siphons" that discharge heated effluent from the Unit 3 and 4 seal wells to the abandoned Unit 1 and 2 discharge area.

c) FPL Riviera power plant will provide personnel from the BPSM, USFWS, Florida Marine Research Institute, USGS-Sirenia Project, or a designee of these agencies, access to the FPL Riviera plant property to conduct manatee research and monitoring activities which may include, placing, maintaining and downloading data from temperature data loggers. (These temperature data loggers will be used to collect air and water temperature data in an ongoing research effort to better understand manatee behavior patterns in response to artificial warm water refugia and environmental variables. The temperature data loggers will be placed in the discharge canal and at ambient water and air locations.) Access would be limited to normal business hours (8:00am - 5:00pm) unless arrangements are made in advance with the FPL Riviera power plant.

d) Intake Area: No special surveys will be required for the intake area.

Discharge Area: No special surveys will be required for the intake area.

e) Should FPL decide to retire these units, notice will be provided to FWC and USFWS as soon as practical after a definite decision is made or, if possible, at least five years prior to the date of retirement.

f) To assist in documenting long-term use patterns of this facility, FPL should conduct periodic aerial surveys of manatees at the Riviera facility. The continuation of the ongoing statewide aerial survey that FPL has funded in the past years meets these criteria.

g) The FPL Rivera power plant will provide phone numbers for weekday and weekend notification of appropriate plant personnel for the purpose of allowing FWC or USFWS to coordinate manatee rescue operations as necessary.

2) FPL actions, pursuant to this plan, that will be conducted on a one-time basis unless there are significant physical or operational changes to the FPL Riviera power plant.

   a) Provide a site map of the facility as a part of the plan that includes the following information;

      1. The location of the intake pipes and outfall pipes.
      2. Proximate streams, rivers, bays, etc.
      3. The location of the condenser inlet and outlet temperature monitoring stations.
      4. The location of any fuel barge docking facilities in relation to the discharge canal.
      5. The delineation of the no-entry boundary at the discharge canal.

   b) In order to evaluate and determine what portions of the thermal discharge will provide a sufficient warm water refuge for manatees under potential cold stress water conditions; the FPL Riviera power plant will, within two (2) years of the effective date of this plan, provide a profile of the thermal gradient (either actual or calculated) of the discharge canal waters, as well as its gross bathymetry, at the mean rate of discharge when the ambient water temperature reaches a seasonal low.

FLORIDA POWER & LIGHT – RIVIERA PLANT
MANATEE PROTECTION PLAN

1a) STANDARD MANATEE CONSTRUCTION CONDITIONS FOR ARTIFICIAL WARM WATER REFUGIA DURING THE PERIOD OF NOVEMBER 15 THROUGH MARCH 31.

The permittee shall comply with the following manatee protection conditions:

a. The permittee shall instruct all personnel associated with in-water work within the discharge canal and/or the warm water refuge of the potential presence of manatees and the need to avoid collisions with manatees. All vessels used in the operation or in association with the in-water work shall have an observer on board responsible for identifying the presence and location of manatee(s).

b. The permittee shall advise all construction personnel that there are civil and criminal penalties for harming, harassing, or killing manatees which are protected under the Marine Mammal Protection Act of 1972, The Endangered Species Act of 1973, and the Florida Manatee Sanctuary Act.

c. All vessels associated with in-water work associated with the discharge canal and/or warm water refuge shall operate at "no wake/idle" speeds at all times while in the manatee warm water refuge area. All vessels will follow routes of deep water whenever possible.

d. If manatee(s) are seen within the discharge canal and/or warm water refuge area all appropriate precautions shall be implemented to ensure protection of the manatee(s). These precautions shall include the immediate shutdown of equipment if necessary. Activities will not resume until the manatee(s) has departed to a safe distance on its own volition.

e. Any collision with and/or injury to a manatee shall be reported immediately to the Florida Fish & Wildlife Conservation Commission at (1-800-342-5367). Collision and/or injury should also be reported to the U.S. Fish and Wildlife Service in Jacksonville (1-904-232-2580).

United States Department of the Interior

FISH AND WILDLIFE SERVICE
6620 Southpoint Drive, South
Suite 310
Jacksonville, Florida 32216-0912

IN REPLY REFER TO:

June 24, 2008

Randall LaBauve, Director
Environmental Services
Florida Power and Light Company
700 Universe Boulevard
Juno Beach, Florida 33408

Dear Mr LaBauve:

The U. S. Fish and Wildlife Service (Service) appreciates Florida Power and Light Company's (FP&L) efforts to notify us, the Florida Fish and Wildlife Conservation Commission (FWC), and others about plans to repower the Canaveral and Riviera Beach power plants and company concerns regarding manatees known to use these sites.

Repowering efforts will involve closing the plants for extended periods of time during demolition and construction activities, a process that will ultimately extend the plant's operational lifespan, as well as the associated warm water discharges. The shutdowns will include temporarily eliminating the warm water discharges from each site during the winter when they are typically used by hundreds of manatees.

At present, there are no authorizations in place under either the Marine Mammal Protection Act of 1972 or the Endangered Species Act of 1973 for the incidental take of manatees and their critical habitat. Wintering habitat is the most important biological factor limiting manatee populations and is integral to the recovery of the species. Therefore, it is critical that you minimize impacts and take steps to avoid the loss of any manatees during your transition process, as well as insure that there is no loss of manatee wintering habitat in both the near and long term.

For planning purposes, we recommend that your plan designs include identifying baseline information about the extent of warm water habitat currently used by manatees at both plants. This could include measuring the areas of warm water habitat, discharge temperatures, discharge volumes, and other parameters. The same or similar quantities of habitat will need to be provided at or in close enough proximity to these sites, such that manatees are able to find and use it with minimal disruption. In addition, any locations should include protections from human disturbance, similar to those which are currently in place. Finally, contingency plans currently under development by FWC, the Service, FP&L and others, should be completed and operational during the transition in the event that manatees do not respond as expected.

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COMPANY Florida Power & Light Company (Direct)
WITNESS R. R. Labauve (RRL-4)
DATE 11/02/09

FP&L is a valued partner in the conservation and recovery of the manatee and we are confident that you will make every effort to provide for manatees as you move ahead. We look forward to working with you on this important issue, and would appreciate an opportunity to meet with you to discuss this further Please do not hesitate to contact us if you have any questions or concerns.

Sincerely,

Dave Hankla
Field Supervisor

CC: Sam Hamilton, Regional Director, Atlanta, Georgia
Ken Haddad, Director, Florida Fish and Wildlife Conservation Commission, Tallahassee, Fl

and Light Company effective July 1, 1982, or as may be subsequently revised. (Attached as Exhibit B.)

6. Reservation of Legal Rights

The Department recognizes that the NRC has exclusive authority in certain areas related to the construction and operation of Turkey Point Units 3 and 4. These conditions of certification do not limit, expand or supersede any federal requirement or restriction under federal law, regulation, or regulatory approval or license. Compliance with the conditions herein does not constitute a waiver of the applicant's responsibility to comply with all applicable NRC requirements. Applicant's acceptance of these radiological conditions of certification does not, in and of itself, constitute a waiver by Applicant of any claim that any such radiological conditions are invalid under the doctrine of federal preemption or otherwise by law.

7. Annual Radiological Environmental Operating Report

Upon submittal to the NRC, a copy of the Annual Radiological Environmental Operating Report for Turkey Point Units 3 & 4 shall be provided to the Department's Siting Coordination Office.

VIII. INDUSTRIAL WASTE DISCHARGES

Any discharges during construction and operation of Units 3, 4 & 5 shall be in accordance with all applicable provisions of NPDES permit No. FL0001562-004-IW1N (attached as Appendix D) as well as any subsequent modifications, amendments and/or renewals.

IX. BISCAYNE BAY SURFACE WATER MONITORING

As proposed, the Turkey Point Units 3 and 4 uprate project may cause an increase in temperature and salinity in the cooling canal system. Field data is needed in order to determine impacts of the proposed changes in the Turkey Point cooling canal system on Biscayne Bay.

A. Within 180 days following certification of Units 3 & 4, FPL shall submit a Biscayne Bay Surface Water Monitoring Plan (Plan) pursuant to Chapter 62-302, F.A.C. to the DEP Southeast District Office for review and approval. The Plan shall include, at a minimum, the following components:

1. salinity and temperature monitoring within the surface waters of the Bay, including the Biscayne Bay Aquatic Preserve; (Specific parameters to be measured, including specific conductance and temperature, shall be sampled in accordance with Chapter 62-160, F.A.C.);

2. a minimum of five monitoring stations located near shore in the vicinity of the Turkey Point Plant; and

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COMPANY Florida Power & Light Company (Direct)
WITNESS R. R. Labauve (RRL-5) (Previously RRL-1)
DATE 11/02/09

3. specific monitoring locations, sampling frequencies and methods, and specific parameters to be monitored.

B. This monitoring data shall be compared to data using compatible monitoring instrumentation already in place in Biscayne Bay.

C. FPL shall continue the monitoring of salinity and temperature in the cooling canals under its industrial waste water facility permit.

D. If the Department determines that the pre- and post-Uprate salinity and temperature monitoring data indicate potential adverse changes in the surface water in Biscayne Bay, then the Department may propose additional measures to evaluate or to abate such impacts to Biscayne Bay.

E. The Plan, including monitoring locations, shall be approved prior to implementation. The Department shall indicate its approval or disapproval of the submitted plan within 90 days of the originally submitted information. In the event that the Department requires additional information for the licensee to complete, and the Department to approve the Plan, the Department shall make a written request to the licensee for additional information no later than 30 days after receipt of the submitted information. Any changes to the approved Surface Water Monitoring Plan shall be approved by Coastal and Aquatic Managed Areas personnel in consultation with other FDEP personnel.

[62-160, 62-302, 62-302.700, 62-520.600, F.A.C.]

X. SURFACE WATER, GROUND WATER, ECOLOGICAL MONITORING

This is a consolidated condition agreed upon by three agencies, Department of Environmental Protection (DEP), Miami-Dade County Department of Environmental Resource Management (DERM) and the South Florida Water Management District (SFWMD). This consolidated condition sets forth the framework for new monitoring and, as may be needed, abatement or mitigation measures, for approval of FPL's Turkey Point Units 3 and 4 Uprate Application. Specific monitoring and potential modeling parameters will be identified and implemented pursuant to a monitoring plan as part of a supplemental agreement between FPL and the SFWMD as described below.

A. In addition to the monitoring framework set forth in this consolidated condition, within 180 days after Certification, FPL shall execute a SFWMD approved Fifth Supplemental Turkey Point Agreement ("Fifth Supplemental Agreement") to the original 1972 Agreement between FPL and the SFWMD pertaining to FPL's obligation to monitor for impacts of the Turkey Point cooling canal system on the water resources of the SFWMD in general and the facilities and operations of the SFWMD (the "Agreement"). Subject to the SFWMD's approval, FPL shall also amend the Agreement's Revised Operating Manual as referenced in paragraph C. "Monitoring Provisions" (the "Revised Plan") of the Fourth Supplemental Agreement, dated July 15,

1983. The Revised Plan shall be incorporated into the Fifth Supplemental Agreement and shall include assessment of potential impacts to surface water and ground water including wetlands, as needed, in the vicinity of the cooling canal system. The specific monitoring boundaries shall be determined as part of the Revised Plan.

B. The Revised Plan shall be designed to be in concurrence with other existing and ongoing monitoring efforts in the area and shall include but not necessarily be limited to, surface water, groundwater and water quality monitoring, and ecological monitoring to:

1. delineate the vertical and horizontal extent of the hyper-saline plume that originates from the cooling canal system and to characterize the water quality including salinity and temperature impacts of this plume for the baseline condition;

2. determine the extent and effect of the groundwater plume on surface water quality as a baseline condition; and

3. detect changes in the quantity and quality of surface and ground water over time due to the cooling canal system associated with the Uprate project. The Revised Plan shall include installation and monitoring of an appropriate network of wells and surface water stations. The Revised Plan shall be approved by the SFWMD in consultation with the DEP Office of Coastal and Aquatic Managed Areas, the DEP Southeast District Office and DERM.

C. FPL shall transmit electronic copies of all data and reports required under the Fifth Supplemental Agreement and the Revised Plan in accordance with timeframes as approved in the Fifth Supplemental Agreement to:

SFWMD, Director, Water Supply (or alternative transmittal procedures to be described in the Fifth Supplemental Agreement);

Miami-Dade County, Director, DERM;

DEP, Director, Southeast District Office;

DEP Siting Coordination Office

DEP, Director, Biscayne Bay Aquatic Preserve Manager,

D. If the DEP in consultation with SFWMD and DERM determines that the pre- and post-Uprate monitoring data: is insufficient to evaluate changes as a result of this project; indicates harm or potential harm to the waters of the State including ecological resources; exceeds State or County water quality standards; or is inconsistent with the goals and objectives of the CERP Biscayne Bay Coastal Wetlands Project, then additional measures, including enhanced monitoring and/or modeling, shall be required to evaluate or to abate such impacts. Additional measures include but are not limited to:

1. the development and application of a 3-dimensional coupled surface and groundwater model (density dependent) to further assess impacts of the

Uprate Project on ground and surface waters; such model shall be calibrated and verified using the data collection during the monitoring period;

2. mitigation measures to offset such impacts of the Uprate Project necessary to comply with State and local water quality standards, which may include methods and features to reduce and mitigate salinity increases in groundwater including the use of highly treated reuse water for recharge of the Biscayne Aquifer or wetlands rehydration;

3. operational changes in the cooling canal system to reduce any such impacts; and/or

4. other measures to abate impacts as may be described in the Revised Plan.

[Sections 373.016, 373.223, F.S.; Rules 40E-4.011, 40E-4.301, 40E-4.302, F.A.C.; Sections 62-302 and 62-520, F.A.C.; Section 24-42, Code of Miami-Dade County, Miami-Dade County Comprehensive Development Master Plan (CDMP) Land Use Element, Conservation Element, Intergovernmental Coordination Element, Coastal Management Element.]

XI. COOLING CANAL SYSTEM

Permits and approvals that regulate the operation of the cooling canal system are incorporated herein and attached as Appendices. These permits and approvals shall be fully enforceable by both the permitting agency and as Conditions of Certification for Units 3 and 4. Any violation of such permits and approvals, where it is determined that Units 3 and 4 are the cause, shall also be a violation of these Conditions of Certification.

XII. WATER MANAGEMENT DISTRICT

A. General

1. If this Certification is transferred, pursuant to Condition IV.O., from the Licensee to another party, the Licensee from whom the Certification is transferred shall remain liable for corrective actions that may be required as a result of any violations that occurred prior to the transfer.

2. This Certification is based in part on the Licensee's submitted information to the SFWMD which reasonably demonstrates that harm to the site water resources will not be caused by the authorized activities. The plans, drawings and design specifications submitted by the Licensee shall be considered the minimum standards for compliance with conditions XI.

3. This project must be constructed, operated and maintained in compliance with and meet all non-procedural requirements set forth in Chapter 373, F.S., and Chapters 40E-2 (Consumptive Use), 40E-3 (Water Wells), and 40E-20 (General Water Use Permits), F.A.C.

TURKEY POINT PLANT GROUNDWATER, SURFACE WATER, AND ECOLOGICAL MONITORING PLAN

June 11, 2009

(as revised by the Agencies on July 16, 2009)

DRAFT

Prepared for:

Florida Power & Light Company

FPL

Prepared by:

ecology and environment, inc.
International Specialists in the Environment

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 11
COMPANY Florida Power & Light Company (Direct)
WITNESS R. R. Labauve (RRL-6) (Previously RRL-2)
DATE 11/02/09

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Acronyms and Abbreviations

BBAP	Biscayne Bay Aquatic Preserve
BBCW	Biscayne Bay Coastal Wetlands
BBSW	Biscayne Bay Surface Water
BBGW	Biscayne Bay Groundwater
BBSWGW	Biscayne Bay Surface Water and Groundwater
BNP	Biscayne National Park
BOD	Biological Oxygen Demand
B^{+}	Boron ion
Br^{-}	Bromide ion
BSL	Below Sea Level
°C	Degrees Celsius
Ca^{2+}	Calcium ion
Cl^{-}	Chloride ion
CCS	Canal Cooling System
CDMP	Comprehensive Development Master Plan
CERP	Comprehensive Everglades Restoration Plan
cm	Centimeter
COD	Chemical Oxygen Demand
CRP	Continuous Resistivity Profiling
D	Deuterium
DBHYDRO	South Florida Water Management District Hydrologic and Environmental Database
DERM	Miami-Dade Department of Environmental Resource Management
DO	Dissolved Oxygen
DTS	Distributed Temperature Sensing
E & E	Ecology and Environment, Inc.
F^{-}	Fluoride ion
°F	Degrees Fahrenheit
F.A.C.	Florida Administrative Code

FDEP	Florida Department of Environmental Protection
FIU	Florida International University
FKAA	Florida Keys Aqueduct Authority
FPL	Florida Power and Light Company
ft	Feet
fpd	Feet Per Day
GSD	Ground Sampling Distance
HCO_3^-	Bicarbonate ion
H_2O	Water
ID	Interceptor Ditch
IWWF	Industrial Wastewater Facility
K	Hydraulic Conductivities
K^+	Potassium ion
Kg	kilogram
Km	kilometer
LIDAR	Light Detection and Ranging
M	Meters
µm	Micrometer
Mg^{2+}	Magnesium Cations
mg/L	Milligrams Per Liter
MW	Megawatt
µS	MicroSiemens
Msl	Mean Sea Level
MLW	Mean Low Water
N	Nitrogen
Na	Sodium
NA	Not Applicable
NAD	North American Datum
NAVD	North American Vertical Datum
ND	Not Detectable
NPS	National Park Service
NGVD	National Geodetic Vertical Datum
NSF	National Science Foundation

NTU	Nephelometric Turbidity Units
O	Oxygen
ORP	Oxidation-Reduction Potential
P	Phosphorus
pH	Potential of Hydrogen
ppm	Parts Per Million
Ppt	Parts Per Thousand
PSS78	Practical Salinity Scale of 1978
psu	practical salinity units
PVC	Polyvinyl Chloride
QA/QC	Quality Assurance/Quality Control
SFWMD	South Florida Water Management District
$SO4^{2-}$	Sulfate Anion
Spp	Species (plural)
SRP	Soluble Reactive Phosphorus
SWIR	Short-Wave Infrared
T	Tritium
TBD	To Be Determined
TDS	Total Dissolved Solids
TIR	Thermal Infra-Red
TP	Total Phosphorus
TPCSW	Turkey Point Canal Surface Water
TPGW	Turkey Point Groundwater
USACE	United States Army Corps of Engineers
USGS	United States Geologic Survey
VNIR	Visible to Near Infra-Red
WRIR	Water Resources Investigations Report
	[redacted]

1
Introduction

This Monitoring Plan (Plan) has been developed pursuant to Conditions of Certification (COC) IX and X of the Power Plant Site Certification for the Florida Power & Light (FPL) Turkey Point Plant Units 3 and 4 Nuclear Power Plant Unit Combined Cycle Plant # PA 03-45 (Uprate Certification). COC IX and X are attached hereto as Appendix A.

The Plan to be implemented by FPL pursuant to Conditions IX and X of the Units 3 and 4 Uprate Certification incorporates contributions from the Florida Department of Environmental Protection's Office of Coastal and Aquatic Management Areas and its Southeast District Office (collectively, FDEP), the South Florida Water Management District (SFWMD), Miami-Dade County's Department of Environmental Resources Management (DERM) (collectively, the Agencies), and Biscayne National Park.

The Monitoring Plan shall provide information to determine the vertical and horizontal effects and extent of the cooling canal system (CCS) water on both surface and groundwater and ecological conditions surrounding Turkey Point (see Figure 1-1). It includes monitoring of surface water, groundwater, and ecological conditions prior to implementation of Uprate modifications and after implementation of the Uprate. Prior to the start-up of the Uprate and following implementation of the Uprate, data shall be collected using monitoring for ground and surface water levels, specific conductance, temperature, CCS tracer suite constituents, tidal influences, preferential groundwater flow paths, surface and groundwater quality (including CCS constituents), rainfall, and ecological conditions.

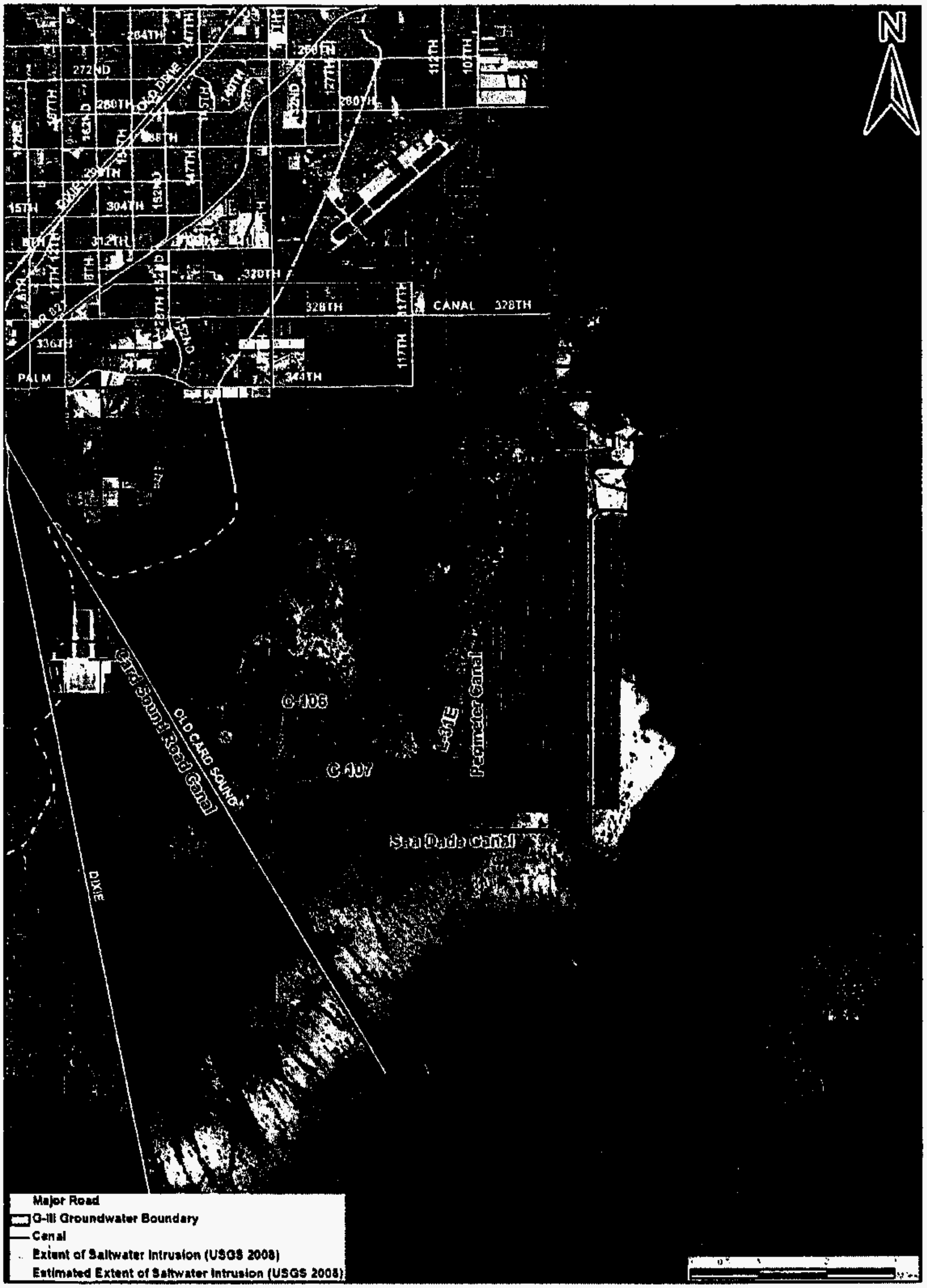

Figure 1-1. Turkey Point Surrounding Habitats. (add in legend G-III should read FPL G-III)

1.1 PLAN MODIFICATION PROCEDURES

The COC includes provisions for the additional measures beyond current Plan specifications as described above. If the SFWMD, in consultation with the FDEP and DERM, determines that the monitoring data:

- is insufficient to evaluate changes as a result of the project; or
- indicates harm or potential harm to the waters of the State including ecological resources; or
- exceed State or County water quality standards; or
- is inconsistent with the goals and objectives of the CERP Biscayne Bay Coastal Wetlands Project,
- then additional measures, including enhanced monitoring and/or modeling, shall be required to evaluate or to abate such impacts as described in COC X.D.(1-4) of the Uprate Certification.

1.1.1 Adaptive Monitoring of Groundwater and Surface Water

The development of this Plan was based on limited existing hydrologic or ecological information. While we expect that most information needs will be met by implementing this Plan, we also expect to learn from the new information collected. New findings may indicate a need to modify the Plan, leading to the collection of additional information (e.g. new parameters, locations, frequencies) and/or decrease in some sampling and analysis. Such an adaptive approach requires timely data analysis, reporting, and initial consensus building regarding Plan modifications.

1.1.2 Adaptive Approach for Ecological Monitoring

It is anticipated that a phased monitoring approach shall be implemented. Both the resistivity surveys and the porewater surveys are considered the first phase (Phase I) of delineating the extent of the CCS plume. These results will be assessed by the SFWMD is consultation with the other Agencies and may be used to refine the hydrologic monitoring design and identify potential areas of concern. Additional hydrologic information derived from surface water and groundwater monitoring during the first year of this program is also likely to provide such insights. This may lead to recommendations for additional sampling locations and/or parameters that may be incorporated into a second phase of the Monitoring Plan (Phase II) as a result of Phase I findings. The details of Phase II monitoring will be considered by all parties and ultimately specified by the Agencies.

The current Plan emphasizes the use of plant communities, as measured along transects, as ecological indicators. A minimum of two years of information obtained during the pre-Uprate period shall be used to establish a pre-Uprate baseline. This information may also indicate areas (spatial or topical) of special concern, such that Plan modifications are warranted. In particular, transect monitoring within the zones containing stressed vegetation (i.e. atypical mangroves and stunted sawgrass) are considered initial sampling and subject to modification. Other modifications may include the addition of parameters, new locations, or relocation of existing sites. Additional types of monitoring for ecological impacts may need to be added later based on: 1) the data and lessons learned from the initial ecological monitoring described, as well as 2) other things learned based on other biological monitoring that FPL or the Agencies are doing.

1.1.3 Process and Criteria for Plan Modification

The Plan may be modified at any time either by the Agencies or at the recommendations of FPL with Agency approval. Criteria for Plan modification shall be based on the progress toward completion of the objectives of COC IX and X and conditions of the Fifth Supplemental Agreement. Examples of potential Plan modifications are presented below:

- the development and application of a 3-dimensional coupled surface and groundwater model (density dependent), calibrated and verified using the data collection during the monitoring period;
- addition/deletion of monitoring stations for plume delineation based on monitoring data submitted;
- addition of monitoring parameters for water quality or tracer(s) based on results of CCS water characterization or new information regarding potential constituents that may be of concern to water quality or ecological resources;
- modifications for calculation of the water budget;
- reduction of monitoring frequencies and/or parameters based on plume stabilization during the post-Uprate monitoring phase; or
- addition or modification of ecological monitoring stations, parameters or sampling locations based on resistivity surveys, porewater surveys, or other available information.

The process of this initial consensus building and decision making for Plan modifications includes: 1) regular technical discussions among the technical experts from partner Agencies and FPL, including a semi-annual meeting to discuss sampling results; 2) review and consideration by all Agencies and FPL of any written recommendation from any agency or FPL for a modification of the Plan; 3) decision making by the Agencies, consistent with COC XD and the revised 2009 Agreement between the SFWMD and FPL (the Fifth Supplemental Agreement). During the meetings, report findings, progress towards the Plan objectives, and Plan modifications being considered by the Agencies or FPL will be discussed. Consideration of proposed Plan modifications may be initiated by the Agencies or FPL with prior written communication, either within report submittals or separately. Review comments will then be provided within 60 days of the report submittal, which will include detailed descriptions and implementation schedules of Plan modifications approved by the Agencies.

Monitoring and reporting under this Plan shall continue until the SFWMD provides written notice of termination.

2
Proposed Monitoring Plan

2.1 MONITORING DESIGN STRATEGY

The Plan consists of an integrated system of surface, groundwater, porewater, and ecologic sampling. New monitoring wells shall be installed and a hydrogeologic investigation and surface and groundwater monitoring shall be conducted. All stage recorders and groundwater wells (top of casings) shall be referenced to allow comparison of results across the landscape and at depths. Where available or possible, data collected by other entities will be used to further enhance the understanding of baseline conditions and determination of impacts. Ecological monitoring shall be initiated in areas of presumed stress, along transects, and for spatial characterization.

The approach for monitoring existing conditions at the Turkey Point Plant and adjacent environments is to determine the relationship of CCS water and: a) the underlying groundwater in all directions; b) the western freshwater wetlands, and nearby canals; c) adjacent saltwater wetlands; d) the eastern mangrove shoreline; e) the Biscayne Bay littoral zone; and f) within Biscayne Bay and Card Sound. The tracking of the CCS water movement is proposed through a combination of automated monitoring along with manual data collection of water constituents and tracers of CCS water (discussed in Section 2.2, pending).

The monitoring area shall include the CCS and surrounding areas, as shown in Figure 1-1. Portions of the Florida Keys National Marine Sanctuary, Biscayne Bay Aquatic Preserve (BBAP), BNP, and the Model Land Basin are also included. This description is not intended to limit the scope of the monitoring if it indicates that the plume or its effects extend beyond this area.

Details related to CCS monitoring are described in Section 2.2.1; Development of a Water Budget in Section 2.2.2; Groundwater Monitoring (including well installation, locations and sampling) in Section 2.3; Surface Water Station Locations in Section 2.4; and Ecological Monitoring in Section 2.5. Monitoring related to the operation of the ID is provided in Appendix B.

In delineating the horizontal extent of the plume originating from the CCS, this monitoring Plan shall rely on a "tracer suite," to confirm that impacts observed are associated with the CCS. Table 2-1 summarizes parameters and indicates abbreviations in the Monitoring Plan. Additional parameters not indicated herein may be added as requested by the Agencies without restrictions.

Although shown on maps in the subsequent sections, the exact monitoring locations may need to be adjusted based on access, environmental considerations (i.e., wetland and estuarine impacts), or other findings that warrant placement in an alternative location. Final locations of all sampling sites shall be approved by the SFWMD in consultation with other Agencies prior to placement.

Preliminary investigation into the thermal anomaly located in the NW side of the CCS shall be undertaken after the detailed bathymetric survey (Section 2.2.2 water budget) has taken place. This investigation includes detailed sampling and characterization and shall include surface water sampling for parameters required under the quarterly sampling. The approximate location of the thermal anomaly is from Longitude 80 21 4.79 West, Latitude 25 24 47.13 North, and Longitude 80 21 5.46 West, Latitude 25 24 11.04 North. The exact location should be measured during the bathymetric survey and should be compared to existing reports.

2.2 TRACER SUITE

Pending – Needs to be specified before plan approval

Table 2-1. Elements Proposed for Groundwater/Surface Water Characterization.

Field Parameters	
Temperature (T)	**pH**
Specific Conductance (conductivity at 25°C) in µS/cm.	Oxidation-Reduction Potential (ORP)
Dissolved Oxygen (DO)	Salinity using the Practical Salinity Scale of 1978 (PSS78)
Percent Oxygen Saturation	
Laboratory Parameters	
CGS tracer suite[c]	
Pending – Needs to be specified before plan approval	
Major Ions[c]:	Nutrients:
Calcium (Ca^{2+})	Nitrogen species:
Sodium (Na^{+})	Ammonia (NH_3)[c] - calculated as NH_3
Magnesium (Mg^{2+})	Ammonium (NH_4^{+}) as N[c]
Potassium (K^{+})	Nitrite (NO_2^{-}) as N^3 [c]
Strontium (Sr^{2+})	Nitrate+Nitrite (NO_X) as N[c]
Chloride (Cl^{-})	Total Kjeldahl Nitrogen (TKN)[c]
Bromide (Br^{-})	Total Nitrogen (TN)[c] - calculated
Sulfate (SO_4^{2-})	Phosphorus species:
Fluoride (F^{-})	Total Phosphorus (TP)[c]
Bicarbonate (HCO_3^{-})	Soluble Reactive Phosphorus (SRP)[c]
Boron (B^{+})	Silicate[a]
Alkalinity (ALKA) Alkalinity as $CaCO_3$	Biological Parameters:
Sulfides	Chlorophyll-*a*[a]
	Pheophytin[a]
Total Dissolved Solids (TDS)[c]	
	Other:
	Gross Alpha[a]
Trace Elements[b]:	
Arsenic	Mercury
Barium	Manganese
Beryllium	Molybdenum
Cadmium	Nickel
Chromium (Hexavalent Chromium)	Selenium
Copper	Thallium
Iron	Vanadium
Lead	Zinc

[a] Surface water only, [b] Groundwater only, [c] Both surface and groundwater.

2.2.1 CCS Water Monitoring

The purpose of sampling within the CCS is to characterize the water within it. A total of six stations are proposed along the interior boundary of the CCS and one in the central portion of the CCS (total = 7). These stations (labeled CCS-1 to CCS-7) are located both at the edge and the middle of the CCS system, as well as in the areas that are of the highest and lowest stage. These data shall provide a clear spatial and temporal understanding of the specific conductance and temperature variability within the CCS (Figure 2-1 and Table 2-2).

All stations in the perimeter canals shall have a conductivity, temperature, and depth (CTD) sensor placed approximately one-foot below the surface level, and one approximately one-foot above the bottom of the canal. Stations in shallow water (< 3 ft) shall use one water quality sensor The site in the center of the CCS (CCS-2) shall only have one sensor approximately one-foot above the bottom of the canal; a second sensor is not warranted due to this center canal's shallow depth (~ 3 feet). Sensors shall monitor for temperature, specific conductance (calculated from specific conductivity and temperature) and will help determine the vertical profiles in the CCS canals. Also at each station, water level shall be measured with a fixed senor that is referenced to NGVD 1929 and NAVD 1988 vertical datum.

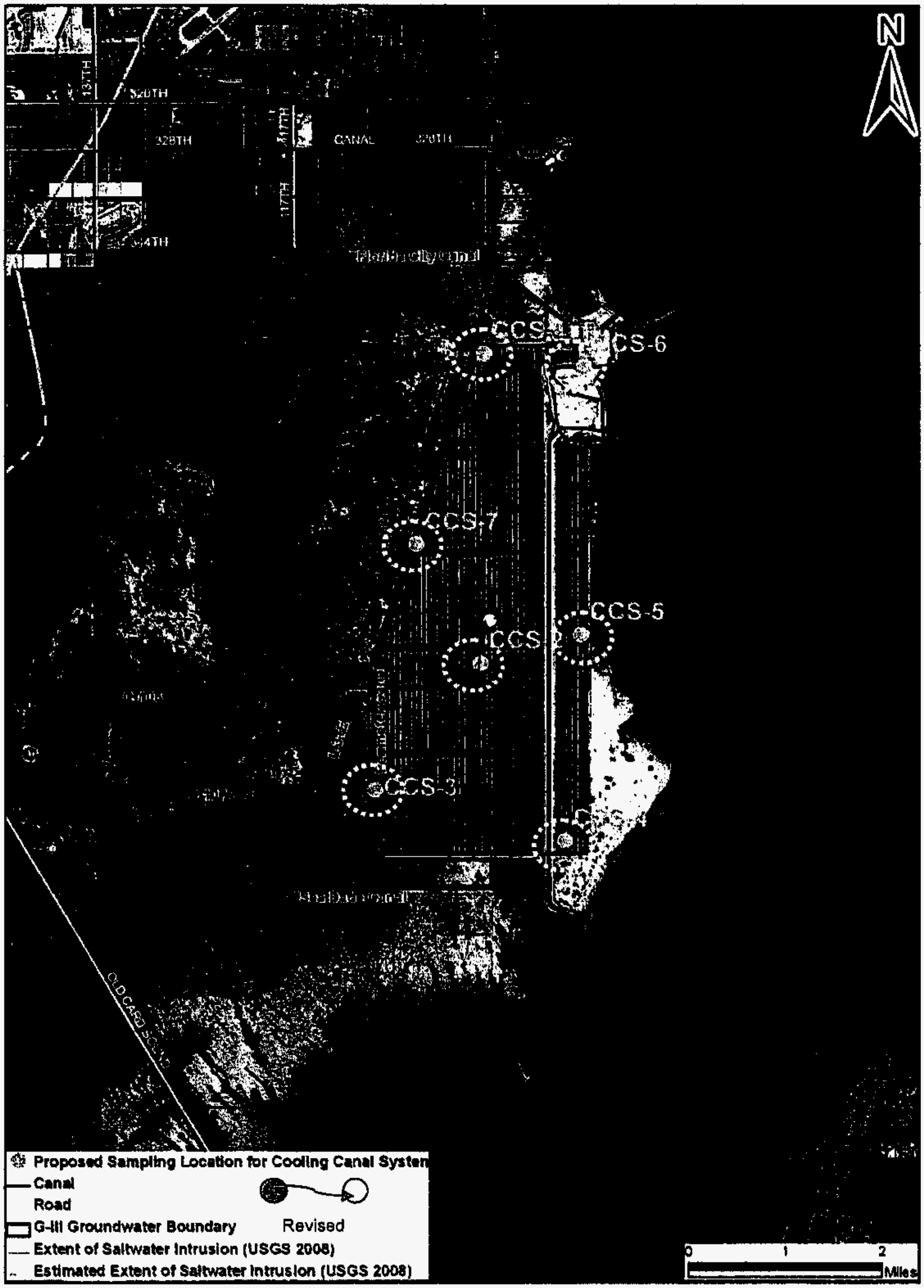

Figure 2-1. Proposed CCS Monitoring Stations. (E &E revise location CCS-2)

Manual water quality monitoring shall be conducted quarterly at the seven CCS stations. Samples shall be collected from each station at each sensor depth with analyses listed in Table 2-1.

Table 2-2. Rationale for the proposed CCS monitoring locations.

Location	Samples	Rationale
Cooling Canal System (CCS) stations: to characterize CCS water and monitor changes Monitoring of water from just below the surface within the CCS and at bottom unless otherwise noted.		
CCS	CCS-1	This site is located in the feeder canal and shall document the specific conductance and temperature of water leaving the plant, where greatest hydraulic stage is observed and shall serve as a station associated with operation of the ID.
	CCS-2	This site is in the middle of the CCS, co-located with TPGW-13, and documents the change in specific conductance and temperature as the water travels down the CCS. This shallow site shall only have one monitoring sensor.
	CCS-3	This site is located in Canal 32 near the southwest corner of the CCS, and will characterize water at this end of the CCS and shall serve as a station associated with operation of the ID.
	CCS-4	This site is located in the Collector Canal at the southeast corner of the CCS, and shall characterize water at this end of the CCS, by the scrub mangrove forest.
	CCS-5	This site is located in the deepest portion of Canal E6 and characterizes the water on its return trajectory back to the plant, nearest the location where DERM has observed atypical mangroves.
	CCS-6	This location in the East Canal measures water as it enters the plant, in the area of lowest hydraulic stage; this site will provide insight into the degree of exchange between CCS and surrounding subsurface hydrology.
	CCS-7	This station is located in Canal 32, halfway down the CCS on the west side and is primarily to serve as a station associated with operation of the ID.

2.2.2 Water Budget and Mass Balance Calculations

Water budget estimates for the CCS were previously computed but proved to be inconsistent in the final volumes (Golder 2008 report; Golder submittal for Uprate; E&E's 2009 letter to SFWMD). Thus, documentation of such volumes has not been accurately documented to date. This new initiative will facilitate improved bathymetric survey work and provide supportive calculations for the volumes of water storage of the CCS.

Developing a water budget for the CCS is essential in evaluating the exchange between the CCS and the regional groundwater, fresh surface waters and Biscayne Bay waters. A key component of the water budget is performing a bathymetric survey that provides the water volume of the CCS concurrently with station measurements and plant operations, ID operations, surface water and groundwater gradients, rainfall, evaporation and tidal influences. Since the volume of water in the CCS is not static, the relationships with effects of the tides, regional groundwater and surface waters and plant operations must be established to develop the appropriate numerical equation. Once this is completed the volume of the CCS can be properly estimated. An uncertainty analysis of the known and unknown parameters shall be completed. Once the bathymetric survey is completed and the numerical relationship between the tides, regional ground and surface water levels, rainfall, evaporation, and plant operations have been established, the water budget analysis process can begin.

As previously discussed, a one–time bathymetric survey of the CCS and each segment of the ID shall be conducted using sonar equipment, and results shall be tied to an established horizontal and vertical datum's (NGVD 1929 and NAD 1988). The positioning (x, y, and z) is critical and requires the use of a high accuracy GPS navigation system (or RTK survey grade equipment). The accuracy of the system should be decimeter GPS locations with vertical control. The geophysical results shall be converted into rectified electronic data set with specific points and coordinates. From this bathymetric survey, a three-dimensional rectified surface shall be developed in AutoCAD (version 14 or higher) that shows the spatial changes in elevation (depth) within the CCS. The volumetric calculations shall be merged by all field water level data (as outlined under 2.4.2.1 Station Construction Task).

Three rainfall stations shall be set up in the CCS system. One station shall be in the north, one at the GW/SW station in the center at TPGW-13 and one station in the south. Rainfall stations shall not be placed nearby structures that may shadow rain or prevent accuracy in rainfall collection. Rainfall buckets shall collect at the same frequencies as the water level data. Data shall be transmitted to the FPL server daily.

Permanent flow stations shall be established within the CCS with the deployment of acoustic Doppler flow meters. Volumetric flow measurements shall be conducted at three strategic locations in the CCS perimeter canal to aid in the estimation of water inputs and losses during the dry and wet seasons. The "stream gauging" techniques shall be taken at each location concurrently over a period of one day.

These locations are near the plant discharge to the CCS: at the bridge constriction on southeast side of the CCS and near the plant intake. (E&E needs to add location on map). Parameters that need to be collected are summarized below:

- Rainfall averaged from three on-site locations
- Plant intake and outflow (doppler)
- Groundwater and surface water levels in and surrounding the CCS

- ID operations, flows, qualities, and rates for each segment
- Meteorological data (solar radiation, wind speed, wind direction, air temperature, relative humidity, or other components necessary to calculate evaporation) at the CCS level
- Other parameters necessary to complete an accurate water budget

Evaporative losses shall be calculated based on meteorological conditions obtained from a weather station collecting data at TPGW-13 station combined with water temperature collected from the CCS surface water stations. Inflows (timing, duration, and frequency) from the ID shall be monitored electronically and merged with the other water budget components.

A time series volumetric spreadsheet (or equivalent) shall be developed based on actual field data. The spreadsheet shall include all components of the water budget. If the water budget spreadsheet contains summarized variables, all backup up or supportive information shall be included in the deliverables. The water budget report shall break down into monthly averages (January through December) and data shall be summarized yearly and shall be prepared along with a budget of ions and or other tracers using the time frames associated with the collection of ionic water quality. For periods with no water quality collection, the average value shall be used to multiply by the flow calculations to yield an overall monthly flows and loads.

The water budget shall include a breakdown for each contribution. This includes but is not limited to:

- Losses/gains to surficial aquifer vertically
- Losses/gains to Biscayne Bay
- Losses/gains to CCS (rainfall, evaporation)
- Losses/gains to surficial aquifer horizontally
- Losses/gains to Biscayne Bay Surface Water
- Losses/gains to Biscayne Bay Groundwater

The updated water budget shall be well documented using the new information and all estimates and assumptions shall be clearly noted. This shall be calculated on a monthly frequency and summed at the end of each year.

2.3 GROUNDWATER MONITORING

The purpose of groundwater monitoring is described in COC IX and X of the Uprate (see Appendix A).

2.3.1 Groundwater Well Locations

Fish and Stewart (1991) showed that the base of the Biscayne aquifer was approximately 106 feet below sea level (bsl) at the G-3321 well location, adjacent to the northwestern portion of the CCS and the L-31E Canal (Figure 2-2). The base of the Biscayne aquifer at G-3321 is shown within a few feet of the contact between overlying limestone with relatively high hydraulic conductivity [> 1,000 feet per day (fpd)] and underlying sandstone with relatively low hydraulic conductivity (10 to 100 fpd) within the Tamiami Formation.

Based on input with the Agencies (SFWMD, FDEP, DERM), a series of groundwater monitoring stations shall be installed. A total of 14 well clusters are included. Figure 2-2 shows revised locations. These well clusters are spatially distributed to facilitate plume monitoring and are generally aligned along transects to aid in determining concentration gradients on a sub-regional scale. Figure 2-2 and Table 2-3 shows the proposed well locations. The exact installation locations may need to be adjusted based on site-specific conditions (access considerations, minimization of environmental impacts) or permitting constraints.

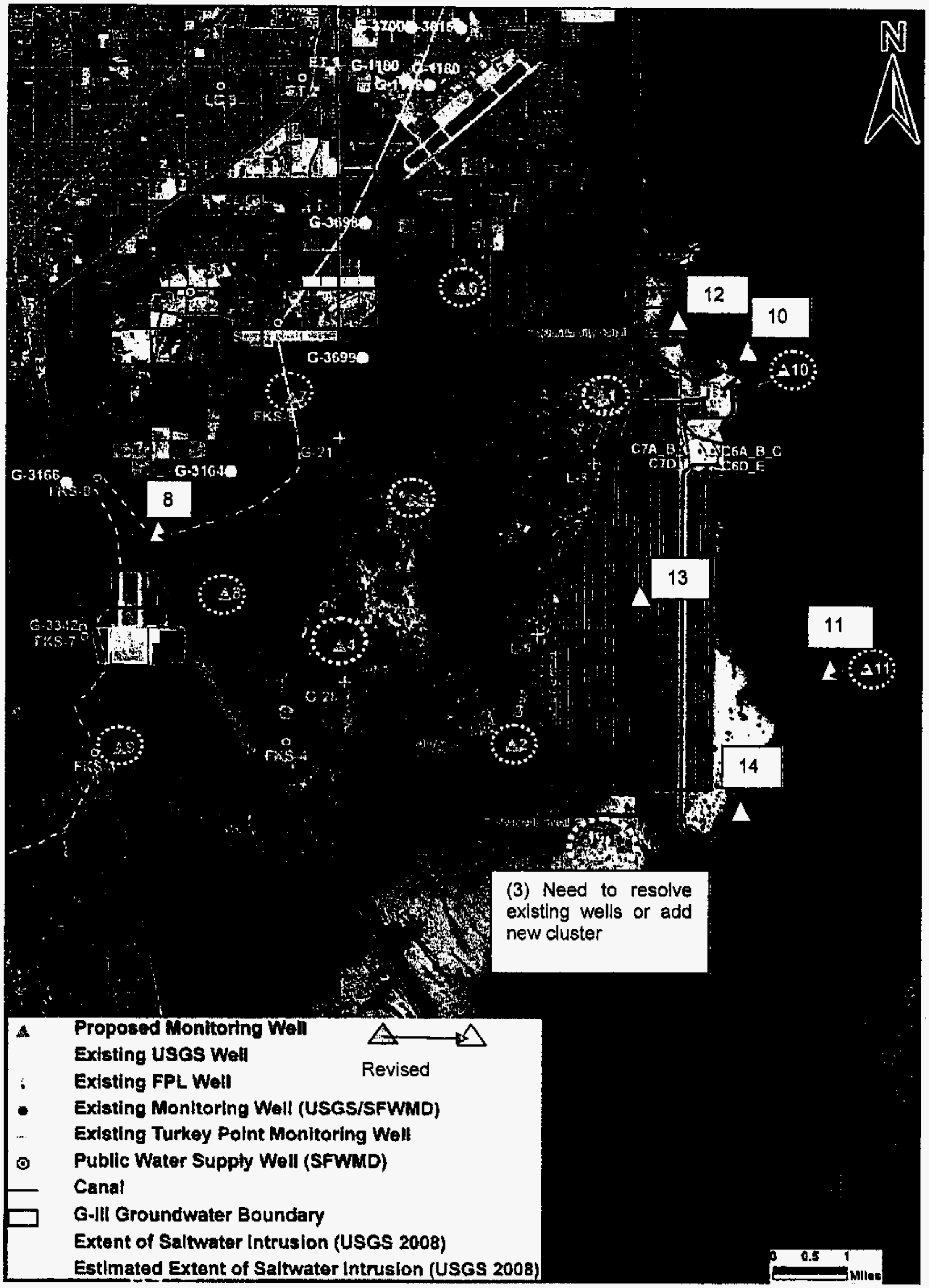

Figure 2-2. Proposed Groundwater Well Cluster Locations. (E & E revise map accordingly)

Table 2-3. Rationale for the proposed groundwater monitoring locations. All locations are approximate until field verification.

Location	Rationale
Groundwater Stations : to establish baseline conditions and delineate limits of CCS plume A cluster of three groundwater monitoring wells at each location to enable sampling from macroporous-permeable zones.	
TPGW-1	Monitor west/northwest of L-31E
TPGW-2	Monitor west of the south-central portion of the CCS.
TPGW-3	Monitor south of the CCS.
TPGW-4	Monitor westward of the CCS.
TPGW-5	Monitor westward of the CCS.
TPGW-6	Monitor northwest of the CCS.
TPGW-7	Monitor west of the CCS and northwest of TPGW-5. Nearest well cluster to Newton Wellfield.
TPGW-8	Monitor west of the CCS and northwest of TPGW-4.
TPGW-9	Reference Well
TPGW-12	Monitor north of the CCS.
TPGW-13	Site is located in the approximate center of the CCS to monitor below the source area of the hypersaline plume.
TPGW-10	Monitor offshore north of the entrance to the barge turning basin.
TPGW-11	Monitor offshore of the CCS in Biscayne Bay.
TPGW-14	Monitor offshore of the CCS in Biscayne Bay.

2.3.2 Groundwater Well Installation

Each well shall be completed with discrete screen intervals in the upper, middle, and lower portions of the Biscayne aquifer, and shall include the base of the plume. To accomplish this task, a pilot hole shall be advanced at each cluster site to delineate to the base of the Biscayne aquifer and characterize the aquifer characteristics and water quality. FPL shall conduct detailed geological sampling in the pilot hole of each cluster. Geological sampling of each pilot hole shall include continuous split spoon (SPT)/core sample collection from surface to total depth. Core samples shall be collected when SPT's are refused. Detailed geological samples shall be correlated to the downhole borehole videos in the final geological report.

Well development shall be conducted on all pilot holes prior to optical borehole imaging and all monitoring wells until field parameters stabilize in accordance with FDEP criteria.

Monitoring well screen intervals shall be site-specific and should represent macroporous and relatively high-permeability zones of the upper, middle, and lower Biscayne aquifer based on the combined results from digital optical imaging (oriented camera system), electromagnetic induction, caliper, flow, conductivity, temperature, gamma ray, full wave form sonic, and borehole logging of the deepest hole (Table 2-4).

In addition, the deepest well at each cluster shall be constructed for periodic (once every year) induction logging across the entire vertical extent of the well. This will enable the monitoring of conductivity changes within the surficial aquifer and potential migration of the plume even in zones that are not screened. Once installed, the network of wells shall be horizontally and vertically surveyed to second order accuracy and referenced to both NGVD 1929 and NAVD 1988 (Appendix C). Well construction requirements to facilitate an electromagnetic induction log are presented in Appendix D.

Table 2-4. Proposed borehole logging methods, descriptions of the properties measured, and types of data obtained.

Type of Log	Properties Measured	Purpose
Optical borehole imaging (OBI)	Imaging of borehole	Determines the 360-degree image of borehole and identify borehole condition and macroporous zones. Provide an oriented optical image of the borehole that compensates for tool spinning.
Induction	Formation and fluid conductivity	Provides data on specific conductance within fluid and formation around the borehole.
Caliper	Borehole diameter	Borehole diameter and determines presence of voids and cavities.
Flow	Flow rate	Identify zones of groundwater flow within borehole.
Temperature	Fluid temperature	Determine temperature variations across depth within borehole.
Gamma Ray	Rock sediment gamma radiation	Provide information on formation characteristics including rock types and changes in lithology.
Full Form Sonic	Lithology and porosity of formation	Provides information on presence and location of potential preferential flow paths.

A well construction spreadsheet supplied by the SFWMD shall be constructed and maintained. The spreadsheet shall include the following parameters: drilling method, geologic sampling method, drilling mud used, well installation date, latitude, longitude, state planar, muck (ground) elevation, ground surface elevation, measuring point at top of casing, depth from TOC, depth at top of screen, screen length, well construction material, screen slot size, gravel pack at screen interval, elevation at top of well screen, elevation at bottom of well screen, centralizers used, project manager, and the source of well information.

Data collected during well installation, including geological sampling (coring or SPT's), detailed lithologic logs, borehole geophysics, digital optical logs, initial induction logs, temperature and flowmeter logs, field water quality data, and well construction details shall be compiled and submitted to Agencies within 30 days of completion of each well. In addition, a summary of well drilling procedures, geophysical logging procedures and instrumentation used shall be provided. Based on wells installed from this monitoring effort and other subsurface geologic data, scaled geologic cross sections, including macroporosity zone and geophysical log overlays, shall be generated and included in the report. This includes information from the induction logs which reveal zones of saline water. In addition, a plan view map showing the location of significant features shall be included. The information generated from this report will enable a better understanding of the movement of groundwater in the area and will provide the basis for interpretation of tracer and water quality monitoring.

2.3.3 Wetland and Biscayne Bay Geophysical Survey

Broad-scale estimates of conductivity surface water and groundwater of wetlands and estuarine regions potentially influenced by the CCS are needed both to assess the spatial extent and magnitude of this influence (including the identification of potential groundwater upwelling zones) and provide information to improve the monitoring design within the adaptive protocols of this Plan. Electromagnetic resistivity surveys from helicopters and boats can provide such broad-scale salinity estimates for both surface water and groundwater (Fitterman and Desczcz-Pan 2001; Swarzenski et al. 2006). Airborne, helicopter-based resistivity surveys, including the wetland areas east of U.S. Highway 1 and Florida City and south of the Mowry Canal, including the CCS and coastal mangrove wetlands, shall be made to map estimated overland surface and groundwater salinity. One overland survey, with generally parallel aerial track lines, separated by approximately 1 km or less, shall be made within one year of the acceptance of this Plan.

Either helicopter-based or boat-based electromagnetic resistivity surveys shall be made over Biscayne Bay (south of the latitude of the Mowry Canal) and over Card Sound. This choice should be made after further comparison of the technical capabilities of these two approaches and in consultation with the SFWMD. Two surveys (wet season and dry season) shall be made within one year of the acceptance of this Plan. If airborne surveys are made, tracks shall be separated by 1 km or less. If boat-based surveys are made, relatively fine-scale tracks (less than 1 km apart) shall be made within 3 km of the shoreline from Card Point to the Mowry Canal, but the remaining area of Biscayne Bay (south of this canal) and Card Sound shall be coarsely surveyed with at least 3 transects that cross these bays eastward to Key Largo, Old Rhodes Key, and Elliott Key. Concurrent surveys using ship-board distributed temperature sensing is recommended. All available specific conductance and salinity data from the surveyed terrestrial and estuarine areas should be utilized to provide best estimates of salinity based on resistivity values.

2.3.4 Groundwater Sampling

Each station shall comprise a combination of three monitoring wells at each site, designed to evaluate the extent of CCS influence and to determine hydraulic gradients (vertical and horizontal) with specific focus on macroporous hydrogeologic zones. Each monitoring well shall be instrumented and automatically monitored for groundwater levels, temperature and specific conductance. The sensors in the monitoring wells shall be placed near the midpoint of the screened section of each well. Salinities measured by sensors shall be calculated using the PSS78.

Quarterly monitoring at each groundwater cluster shall consist of field parameters, major ions, TDS and CCS tracer suite as listed in Table 2-1. Semi-annual monitoring at each groundwater cluster shall consist of all of the above plus nitrogen and phosphorus series. In addition, trace elements shall be monitored semi-annually for twelve months in the groundwater clusters (1, 2, 13 and 14) labeled in Figure 2-2. If trace element concentrations exceed primary and secondary drinking water standards in groundwater samples, monitoring for these parameters shall continue and may be expanded to other stations. All applicable samples shall be analyzed in accordance with Chapter 62-160 F.A.C. at an FDEP approved laboratory facility capable of analyzing samples with a wide salinity range (including hypersaline waters).

FPL shall continue to collect all quarterly data manually (from two depths) from the existing wells L-3, L-5, G-21 and G-28 to compare the information with the new wells, which are more strategically screened. Since there are over 30 years of data from these existing wells, a comparison of the information against nearby wells shall give insight into the accuracy of the historical data. Previously, these wells were monitored quarterly with field instruments. While temperature, specific conductance, and water level shall continue to be monitored with field instruments, samples shall be collected and sent to a laboratory for analysis of the same parameters that shall be the subject of monitoring in the new wells.

To further supplement the groundwater data being collected by FPL, information collected by the others, including but not limited to USGS and the FKAA, may be used upon the Agencies pre-approval. The Agencies will review each proposed well's applicability to the Monitoring Plan based on geologic data and construction details submitted. Currently, the USGS collects chloride data on a semi-annual or quarterly basis and conducts induction logs once a year from a network of coastal wells throughout Miami-Dade County. In some cases there are only a few years of data, and in other cases, over 30 years. Some of these wells are located in the project area and are screened near the base of the Biscayne aquifer.

Figure 2-3 (needs to be revised with updated well cluster locations) provides a summary of the wells that are may be used to supplement the monitoring effort, the associated well depth, and screen interval. Based on input from the USGS, the well construction information on their wells is reliable and all elevations are referenced to NGVD. Further input is needed from FKAA on their wells.

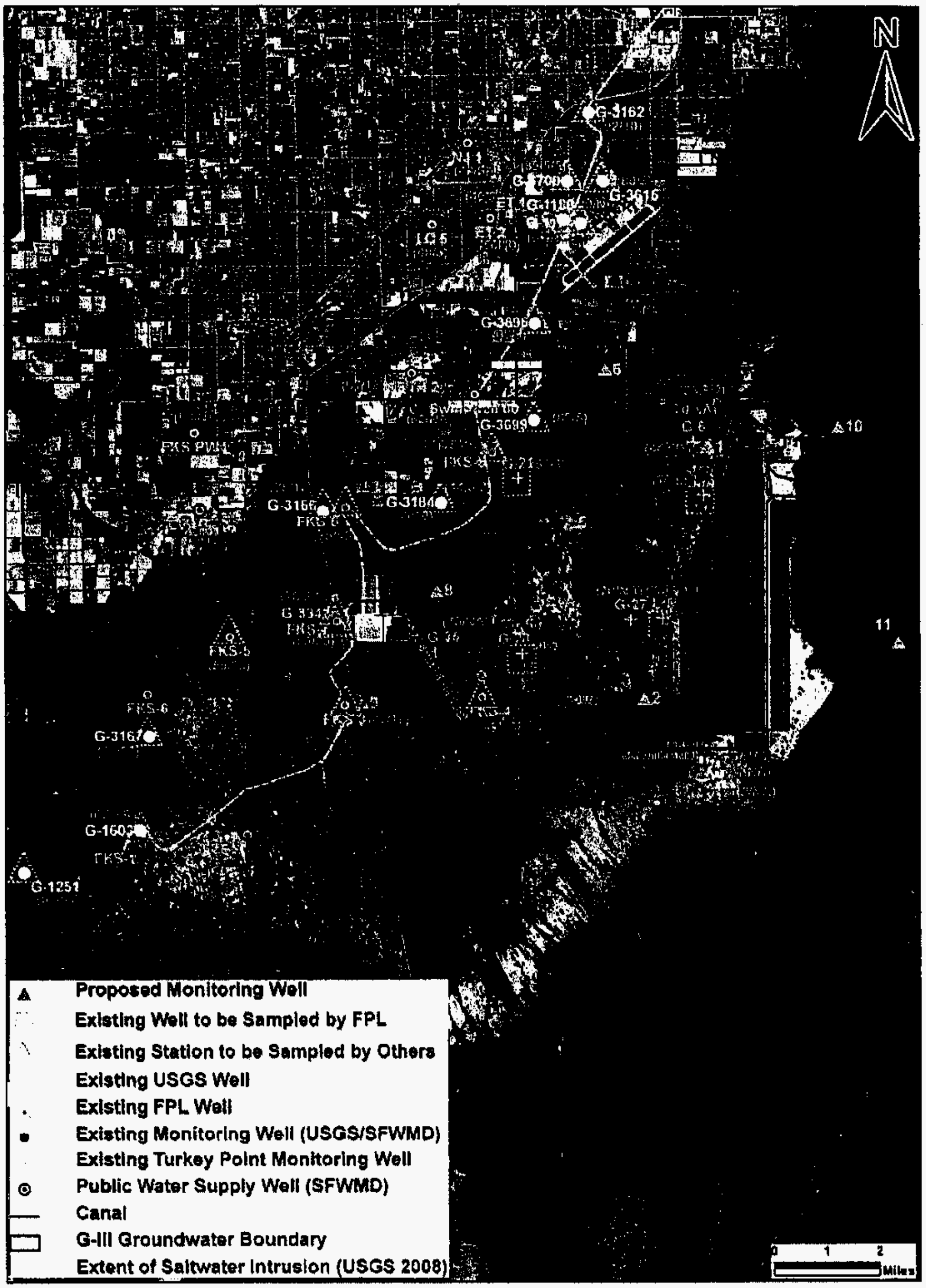

Figure 2-3. Existing Wells Proposed to Supplement Groundwater Monitoring Showing Well Depth / Screen Length.

2.4 SURFACE WATER MONITORING

The purpose of surface water monitoring is described in COC IX and X of the Uprate Certification (see Appendix A). This section focuses on the proposed surface water monitoring in Biscayne Bay and the nearby fresh water and tidal canals, including the L-31E Canal, tidal canal downstream of the S-20 Structure, the Card Sound Canal. Monitoring surface water in the Model Land Basin freshwater wetlands and nearshore mangroves shall be addressed in the Ecological Monitoring section of this Plan.

2.4.1 Surface Water Locations

A total of five surface water stations are proposed in Biscayne Bay, extending offshore along the length of the CCS. BBSW-4 shall be co-located with TPGW-14 while BBSW-3 shall be located with groundwater cluster TPGW-11 (Figure 2-4). Table 2-5 shows the locations of these surface water stations and the rationale for these locations respectively. The exact installation locations may need to be adjusted based on site-specific conditions (access considerations, minimization of environmental impacts) or permitting constraints. The surface water stations shall be located as close to shore as possible, but it is recognized that the water is quite shallow immediately east for much of the CCS.

As shown in Figure 2-4 and Table 2-5, freshwater and surface water stations are proposed at three nontidal surface water locations in the L-31E Canal: one tidal location on the S-20 Discharge Canal, and one tidal location at the Card Sound Canal. A sixth location in the Card Sound Road Canal, away from the influences of the CCS, shall be monitored manually with the quarterly sampling events (add to figure). This is a reference station and may indicate the Card Sound Road Canal's influence on regional saltwater intrusion and the possible impact on the area between Card Sound Road and the CCS.

The L-31E Canal is the closest freshwater water body to the CCS. The L-31E Canal stations shall serve a dual purpose of providing information for the assessment of CCS influences, as well as supporting the monitoring of water levels for ID operation.

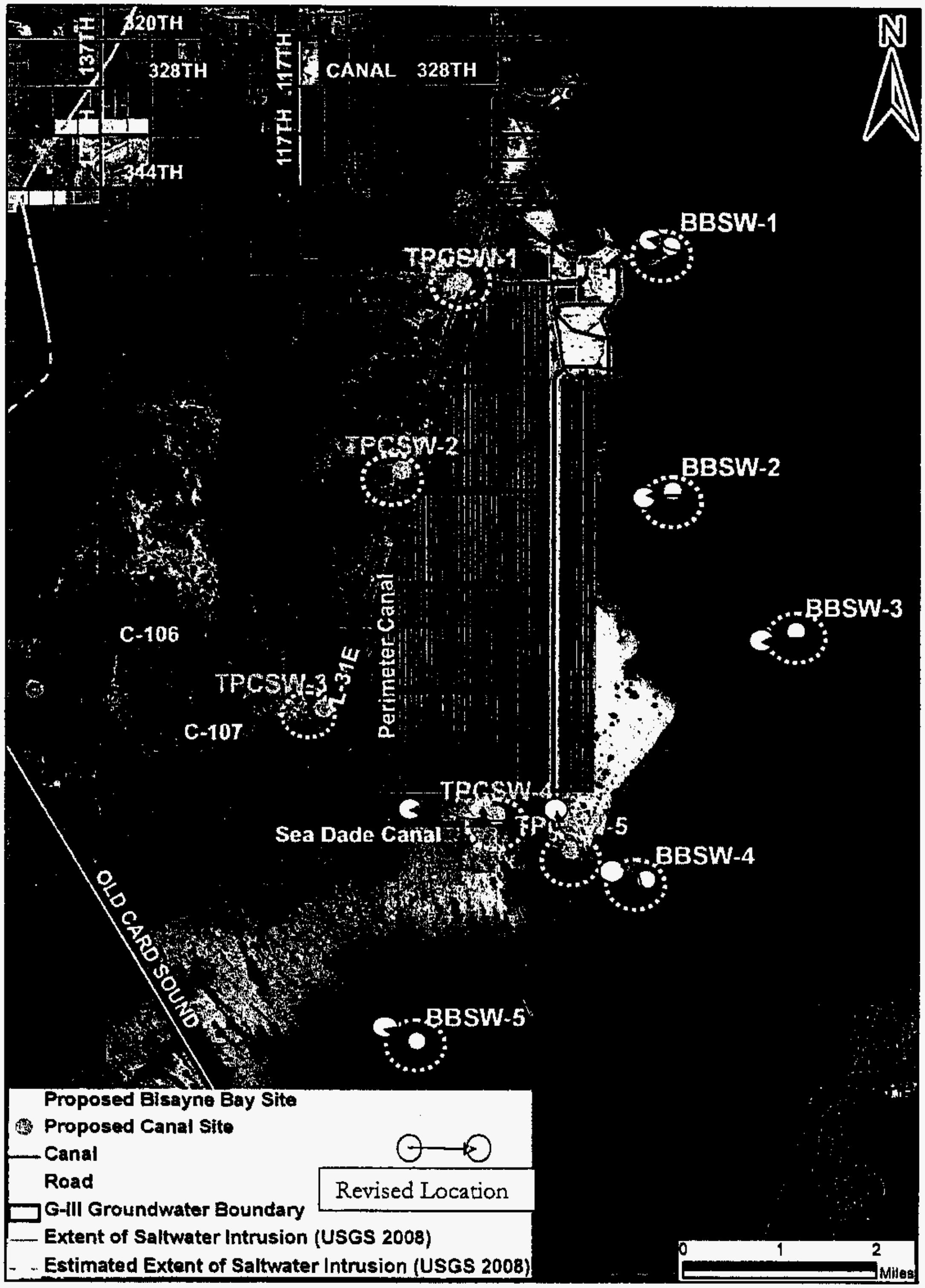

Figure 2-4. Proposed Surface Water Monitoring Sites (need to revise locations).

Table 2-5. Rationale for the proposed surface water monitoring locations.

Location	Sample	Rationale
Biscayne Bay	BBSW-1	This site is in the cut and just offshore the Barge Turning Basin, northeast of the CCS.
	BBSW-2	Located offshore from the scrub mangrove where DERM has observed atypical mangroves to monitor for seepage from the CCS.
	BBSW-3	This site is located near the Arsenicker Keys, just offshore the mangrove forest and co-located with TPGW-11.
	BBSW-4	This site monitors the offshore portion of the CCS south of the Arsenicker Keys and near the mouth of the Card Sound Canal/historical CCS outlet, and co-located with TPGW-14. This site is located in close proximity to a Department of Health radiological monitoring site.
	BBSW-5	This site is located south of the CCS and mitigation bank.
L-31E Canal	TPCSW-1	This site is located northwest of the CCS along ID Transect A to monitor for seepage from the CCS and to aid in the operation of the ID.
	TPCSW -2	This site is located along the middle segment of the CCS and along ID Transect C to monitor for seepage from the CCS and to aid in the operation of the ID.
	TPCSW -3	This site is located by the S-20 structure, at the intersection of the L-31E and C-107 Canals to monitor for seepage from the CCS. It is also part of the ID operations located along Transect E.
S-20 Discharge Canal	TPCSW 4	Sampling station located at the S-20 Discharge Canal. This site shall monitor the extent to which the tidal portions of the drainage canal downstream of the S-20 Structure is affected by the surface waters of the CCS as well as the potential influence of Biscayne Bay on the canal around the CCS.
Card Sound Canal	TPCSW -5	Located in Card Sound Canal, just below the CCS, where manatees have been increasingly observed as reported by DERM.

2.4.2 Surface Water Data Collection

The proposed surface water stations in Biscayne Bay shall measure conditions just above the sediment surface. All stations shall be automated with one set of temperature and conductivity sensors installed horizontally approximately one foot above the sediment surface (Appendix D). All proposed sampling stations in Table 2-5 shall be automated and instrumented similarly to the CCS stations. This will allow for the determination of water level, temperature, and specific conductance at each site.

Data from each surface water station discussed above shall be collected at 15-minute intervals from the top of each hour and remotely uploaded to a database. This monitoring strategy shall allow a continuous assessment of specific conductance and temperature changes in Biscayne Bay and canals in the areas surrounding the Turkey Point Plant. The stage sensors shall be tied to an established datum (NGVD 1929 and NAVD 1988). All sensors shall be inspected and cleaned as needed.

In addition to the proposed automated monitoring, quarterly monitoring at each surface water station shall consist of field parameters, major ions, and TDS and CCS tracer suite, as listed in Table 2-1. Semi-annual monitoring at each surface water station shall consist of all of the above parameters, and nutrients and biological parameters. Gross Alpha shall be monitored semi-annually for 12 months in all stations located within the cooling system. All applicable samples shall be analyzed in accordance with Chapter 62-160 F.A.C. at an FDEP-approved laboratory facility capable of analyzing samples with a wide specific conductance range (including hypersaline waters).

In addition to the data currently collected, where possible, additional data from other entities (Figure 2-6) such as BNP, NRC, USACE, EPA, NOAA, DOI, NPS, DOH, USGS, FWS, DERM and other local governments, and SFWMD will be added to the information collected from this effort to form a more comprehensive understanding of this area. BNP monitors salinity at 34 sites in the area at the same 15-minute sampling frequency (Bellmund et al. 2007), and the sites around the CCS (BISC08B, BISC12B, and BISC13S) will be used to complement the monitoring efforts. Information available from the sampling network in BNP, Audubon Society's nearby sites, and the SFWMD Water Quality sampling network will be reviewed for relevance and applicability in the inclusion of data reporting. Other data that will support this monitoring effort include the SFWMD operations of the S-20 structure, since that affects the water quality at TPCSW-4.

2.4.2.1 Station Construction Tasks/Testing

To maximize implementation of the Plan, it is important to install the surface water stations and groundwater wells in specific steps that are required to initialize other subsequent steps of the Plan. A key component of the water budget (Section 2.2.2) is performing a bathymetric survey that provides the water volume of the CCS concurrently with station measurements and plant operations, ID operations, surface water and groundwater gradients, rainfall, evaporation and tidal influences. Since it will take several days and several tidal cycles to collect the bathymetric survey data, it is important to relate the data collected from the survey back to the elevation of the surficial water tables, surface water elevations, and the elevation of the CCS. To complete this task, it is necessary to complete the well/surface water clusters in the list presented below before conducting the bathymetric survey.

All Biscayne Bay Groundwater/surface water locations:

- CCS Groundwater/surface water location in the center (TPGW-13) of the CCS
- CCS Surface water level and WQ locations
- ID and L-31E Surface water level and WQ locations
- GW Stations at the North (TPGW-12)
- GW Stations at the South [redacted]
- GW Stations at the TPGW-3
- GW Stations at the TPGW-2

Items listed above are all related to the bathymetric survey. Once the tasks above are completed, the bathymetric survey shall be conducted as described under the Water Budget section (Section 2.2.2).

2.5 ECOLOGICAL MONITORING

2.5.1 Overview and Strategy

The purpose of ecological monitoring is described in COC IX and X of the Uprate (see Appendix A). Ecological monitoring is necessary to establish the current, pre-Uprate status of major ecological conditions and biotic components, the extent to which CCS operations impact conditions and components, and the extent to which Uprate implementation further impacts and changes these conditions and components. Ecological conditions of primary (but not exclusive) interest, related to CCS operations and ecological responses, are salinity, a tracer set of CCS water, and nutrients. Biotic components of primary interest are marsh vegetation (freshwater graminoid and woody), mangrove, submerged aquatic vegetation (SAV), and benthic fauna in and adjacent to Biscayne Bay.

The strategy employed for this Plan is as follows:

- Spatially characterize ecological conditions via broad reconnaissance surveys within one year of Plan approval. These surveys include resistivity surveys of freshwater marsh, Biscayne Bay, and Card Sound (see Section 2.3.3), along with sampling of specific conductance and a CCS tracer suite within the upper 50 cm of soils, sediments, or other bottom-types;
- Within one month of Plan approval, begin identifying areas of potential CCS impact. This will be accomplished by synthesizing existing data relating to the distribution and density of vegetation

using observations and cursory analysis of historical aerial photography;

- Initiate assessment of these impacted areas immediately after they have been spatially identified;
- Establish transects and plots in freshwater marshes, including sampling of specific conductance and a CCS tracer suite, and nutrients in soils and sediments;
- Initiate Biscayne Bay benthic SAV and faunal assessment; and
- Document broad-scale vegetation patterns via pre- and post-Uprate aerial photographic surveys.

2.5.2 Design

The ecological monitoring is based on a BACI (Before-After-Control-Impact) approach. Three zones (freshwater marshes, saline/coastal wetlands, and Biscayne Bay and Card Sound) shall be assessed continuously pre- and post-Uprate. Results shall be compared with changes over this time in reference areas that are ecologically similar, with exposure to similar environmental factors other than CCS operations. The "Triangle Area," between Card Sound Road and US Highway 1 of the Model Lands, is proposed to be the reference area (Figure 2-5). At a minimum, two years of pre-Uprate monitoring shall be performed. Additionally, some measurements shall be taken within the CCS.

Within each zone, a slightly different sampling design is recommended. A transect design is to be used within the northern, eastern, western, and southern marshes (Figure 2-5). Areas that have been identified as containing stressed or atypical vegetation patterns shall be included in the transects and subject to additional evaluation. These stressed areas include the following locations:

1) an atypical mangrove area, east of the CCS (25.41°N, 80.32°W)
2) short fringe mangroves, south of the Sea Dade Canal (25.34°N, 80.33°W)
3) stunted sawgrass site, west of CCS (25.43°N, 80.35°W)
4) pond area in saltwater mangrove area east of CCS (25.3799°N, 80.3268°W)
5) nearshore benthic features within Card Sound (25.4072°N, 80.3273°W)

A transect approach shall also be used in the mangrove wetlands east of the CCS, but because of the small area involved and structure of existing or remnant creeks, these transects may be modified over time to spatially conform with landscape features and areas of potential impact. Within Biscayne Bay and Card Sound, a combination of nearshore-offshore transects and nearshore areal sampling shall be used. For any of these zones, additional study sites shall be added at locations where specific CCS influence is subsequently identified or concerns are noted (e.g., sites of CCS derived groundwater upwelling) and/or other concerns are noted.

2.5.3 Initial Ecological Condition Characterization

Assessment of biotic responses to CCS operations requires information on the spatial distribution of environmental conditions that affect biota and are potentially influenced by CCS water. A condition of primary interest is specific conductance (especially soil and sediment specific conductance for vascular plants), but other conditions (such as temperature and nutrients) are important ecological factors. Measurement of a CCS tracer suite is essential to establish the extent of CCS connectivity in a given adjacent zone. Initial information on salinity distribution will be derived from two sources: 1) electromagnetic resistivity surveys (Section 2.3.3) of wetlands, the CCS, Biscayne Bay and Card Sound; and 2) porewater surveys of these areas, including the freshwater and saline wetlands adjacent to the CCS and Biscayne Bay and Card Sound. Porewater shall be analyzed for conductivity within the root zone (about 30 cm deep, but limited to the top 50 cm), along with the CCS tracer suite analysis at a subset of locations. Results from these surveys shall identify zones of CCS water connectivity with surface sediments and soils via seepage and groundwater pathways, providing information on potential ecological influence of the CCS, as well as a basis to improve the monitoring design within the adaptive protocols of this Plan.

The resistivity surveys, described in Section 2.3.3, shall encompass the wetland areas adjacent to the CCS, the CCS, and Biscayne Bay and Card Sound. Results from these surveys will be used to locate potential upwelling zones containing CCS water. A minimum of one survey over land and two seasonal surveys over Biscayne Bay and Card Sound (one wet season and one dry season) shall be completed within the first year of the Plan implementation.

A broad-scale survey of porewater temperature, conductivity, and the CCS tracer suite shall be made in adjacent wetlands and in Biscayne Bay and Card Sound during the first dry season after acceptance of this Monitoring Plan. Specific conductivity and temperature profiles (at 10 cm intervals to 50 cm or bedrock) shall be measured in situ (using field meter and probes) at more than 100 points in the wetland and more than 100 points in Biscayne Bay and Card Sound. The boundaries of the surveyed areas shall be as far west as Tallahassee Road and Card Sound Road south of the L-31E, wetlands, and Biscayne Bay as far north as the Florida City Canal, south to Card Point, and east as far and as 3 km offshore from the Biscayne Bay and Card Sound shoreline. Sample sites shall be approximately even in distribution, but some samples may be taken in areas of special interest (such as apparently stressed areas, tree islands, remnant creeks, or sites where groundwater inputs are suspected). If such areas are found to be distinct from adjacent marsh areas, the transect design (described in the

Freshwater Wetland section below) shall be modified to include these areas. Water level (within wetlands) or water depth (within the Bay) shall also be measured and locations of all sampling shall be tracked and identified by GPS. Following analysis of the survey results, and after consultation with the SFWMD, CCS tracer suite measurements shall be made from porewater in the upper 30 cm of cores collected at a subset of sites that, based on specific conductance results, indicate the strongest CCS influence (with at least 30 samples in each wetland zone and 30 samples in Biscayne Bay and Card Sound). In Biscayne Bay and Card Sound, sampling shall be done during a neap tide period, January through March. A second sampling set may be called for, which may include additional parameters pending the results of this initial porewater survey and the resistivity survey sets.

2.5.4 Vegetation Mapping by Aerial Imaging

The distribution, density, and composition of plant communities shall be mapped pre- and post-Uprate from aerial photography and photo-interpretation. The spatial domain of this effort will be as described above for airborne resistivity flights over wetlands (including both freshwater and saline wetlands to the coastline). All methods for photography and interpretation, including ground-truthing, shall be conducted as described in RECOVER's vegetation mapping of the Everglades. However, in addition to identification of dominant species (plant community classification), the proportion of cover shall be estimated within as a set of 5 categories (with 20% cover increments). Specifications of RECOVER methods are described in two SFWMD Statement of Work documents, which will be provided to all interested parties. Pre-Uprate analysis shall be performed on photographs taken for RECOVER in April 2009, which will be provided by SFWMD to FPL or FPL contractors. Post-Uprate analysis shall be conducted on FPL photos taken two to three years after the initiation of Uprate operations. All FPL vegetation mapping work will be closely coordinated with the SFWMD staff that oversee the RECOVER vegetation mapping, with SFWMD review of FPL procedures, such that any duplication of effort and costs are minimized and data quality is maximized. All data derived from both the RECOVER and FPL efforts will be shared between the organizations. Data shall be reported in an ESRI geo-database and GIS format.

2.5.5 Wetland Transect Locations

Ecological assessment of the wetlands will focus primarily on patterns of plant community status and environmental conditions relevant to this community, along transects emanating from the CCS. The approximate locations are shown in Figure 2-5. Three east-west transects (approximately 6 km long) shall be established through the freshwater wetlands (shown in yellow in Figure 2-5) from the CCS into the Model Land Basin at least as far west as Tallahassee Road. Preliminary locations for these three western transects include an area of special concern, adjacent to the CCS western boundary, where observations of sparse and stressed vegetation have been made, as well as western areas that are not obviously influenced by the CCS. Three shorter transects shall run from the northern and southern CCS boundary through freshwater wetlands (in yellow) and saline wetlands (in pink) to the Biscayne Bay and Card Sound coastline. Two of these transects traverse wetlands south of the CCS, with one from the southeast corner and one from the southwest corner of the CCS to Card Sound. A single transect traverses wetlands from the northern CCS boundary to (approximately) the mouth of the Florida City Canal. Three additional short transects shall run from the eastern CCS boundary to the coastline in the saline mangrove wetlands (shown in pink in Figure 2-5) with an orientation dictated by the shape of this narrow coastal area and the location of previously identified atypical mangroves growth and mangrove mortality.

A reference transect (in turquoise in Figure 2-5), approximately 9 km long through freshwater and saline wetlands shall also be established in the "Triangle Area." The final location of these transects and the sample sites selected along them shall be subject to the consent of the SFWMD, in consultation with other Agencies.

2.5.6 Freshwater Wetland Transect Assessments

Sampling along all transects shall be at 3 spatial levels (20 m plots, 5 m and 1 m subplots; Figure 2-6). The exact locations of these plots along the transect shall be jointly determined with the Agencies after an initial dry season assessment along each transect, with measurements every 500 m of field porewater specific conductance and temperature depth profiles to 50 cm depth, along with the CCS tracer suite, as described in the Initial Ecological Condition Characterization section. Additionally, dissolved boron in the upper 30 cm of porewater shall be sampled and analyzed. If no differences in specific conductance are observed along a transect, the plots shall be established at equal distances along the length of the transect (Figure 2-6).

Along each western transect, five 20 m x 20 m major plots shall be set up. Eight sub-plots shall be set up per major plot along each transect. This includes four 5 m x 5 m (pink boxes) and 1 m x 1 m (yellow boxes) subplots that shall be randomly established (Figure 2-6). From each major (20m x 20m) plot, species composition and abundance, woody species cover, herbaceous species cover, and canopy height shall be measured. Percent vegetative cover shall be determined from the aerial imagery, while the other parameters shall be determined from ground assessment. Photographs for each plot shall be digitized, and classification of community types defined for each plot.

During the ground assessment, one 5 m x 5 m subplot shall be randomly established within each quadrant of the larger plot (Figure 2-6). Species diversity and characteristics of woody plant species within each subplot (e.g., height, diameter at breast height) shall be measured. Within the same quadrant, a 1 m x 1 m subplot shall also be randomly established in the marsh to determine the marsh species diversity and density. All sawgrass (*C. jamaicence)* culms and spikerush (*Eleocharis* spp.) stems shall be counted within each subplot. The number of leaves in ten *C. jamaicense* culms shall be counted and measured; similarly, the height of ten *Eleocharis* spp. stems shall be measured. Estimates of plant productivity shall be made in woody vegetation (5x5m) plots from changes in morphology (e.g., diameter at breast height) and leaf litter production. Plant productivity of dominant graminoid species (in 1x1m plots) shall be estimated by leaf biomass turnover measurements. The proposed methodology is consistent with methods used in Everglades National Park by the National Science Foundation (NSF)-funded Long-Term Ecological Research program based out of Florida International University.

Plot (20 m x 20 m) measurements shall be conducted once a year, while the 5 m subplot measurements shall be conducted twice a year, at the end of the wet and dry seasons. Leaf litter production measurements shall be made quarterly. The 1 m subplots shall be measured at three month intervals.

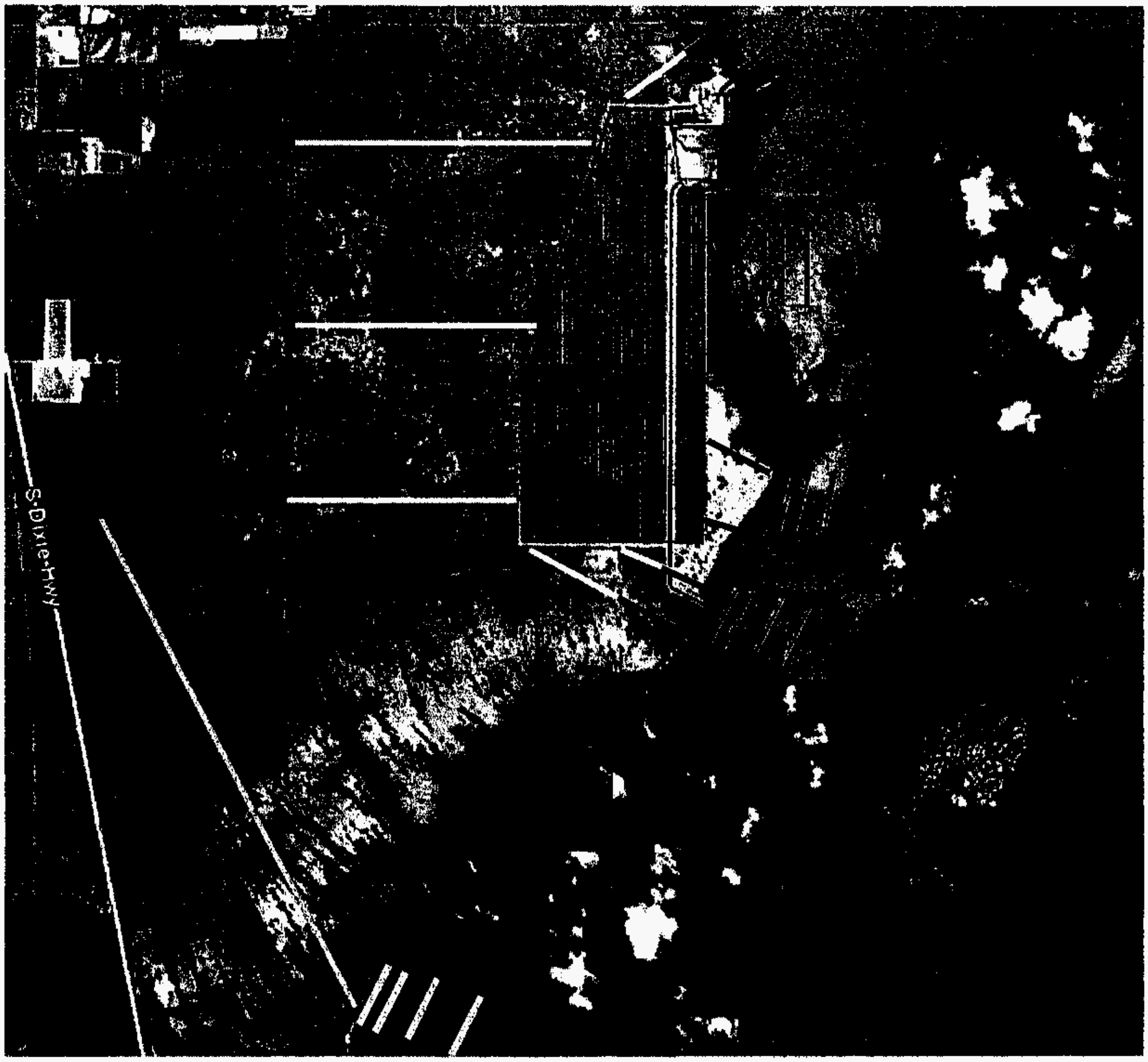

Figure 2-5. Ecological monitoring transects adjacent to the CCS (including freshwater wetlands in yellow and saline wetlands in pink, Biscayne Bay and Card Sound benthic in black) and associated reference transects (in turquoise). Location of the interface of freshwater and saline wetlands shown here is conceptual.

Twice a year (once at the end of the wet and dry seasons), ten leaves/stems of each of the dominant species shall be randomly selected and collected from each plot along each transect for morphological and physiological characterization. Leaf characteristics (i.e., leaf length, width, and thickness, water content) shall be measured prior to the leaves being dried and analyzed for C, N, and P contents, as well for ($\delta^{13}C$). Changes in these plant characteristics over time and among plants within and between transects shall be analyzed for trends and differences.

Water levels, surface water (when present) temperature and specific conductance, soil temperature, and porewater specific conductance and the CCS tracer suite shall be measured at each major plot every 3 months. Porewater nutrients (TP, SRP, NH_4, NO_X, TKN) shall be measured in all subplots twice per year. Bulk soil nutrients (TP, TN, TOC) and bulk density shall be measured in these subplots annually. In major plots with apparently stressed vegetation, sulfide and boron shall also be measured in porewater samples during the first two sampling times to assess these potential stressors. Additionally, specific conductance and temperature shall be measured in L-31E Canal and ID surface waters along the line of these transects.

As described in the Initial Ecological Condition Characterization (Section 2.5.3), the specific conductance and ecological condition of tree islands along potentially remnant streams and other sites of special interest shall be assessed in a preliminary survey. If results from this survey indicate the need for additional information, then additional transects or plots near the three established transects may be added. Sampling shall be consistent with that occurring along transects, but the SFWMD will coordinate Agency review prior to initiation.

Plot site selection, plot design, and sampling along the three shorter freshwater marsh transects north and south of the CCS shall be as described above for the western transects. However, only two major plots shall be established along each of these transects. Plot site selection, plot design, and sampling along the reference freshwater marsh transect within the "Triangle Area" shall be as described above for the western transects, with a total of 5 plots.

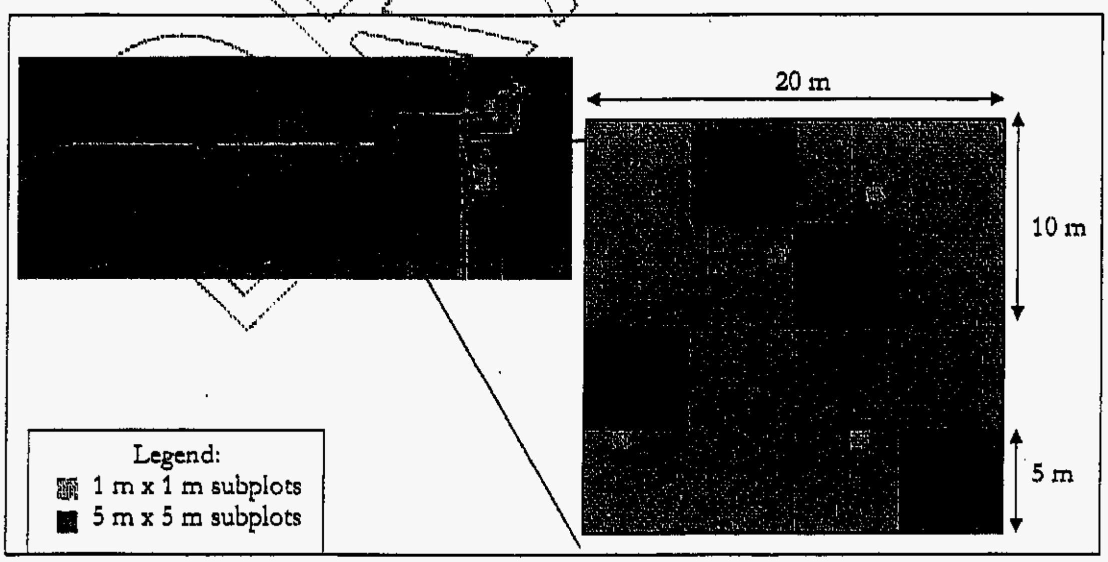

Figure 2-6. Example of a proposed sampling design for ecological monitoring along the transects.

2.5.7 Saline Wetland Transect Assessment

Assessment along the six transects containing saline wetlands (shown in pink in Figure 2-5) shall focus on plant community composition, morphology, productivity, and environmental conditions, similar to that described for the freshwater wetlands. The sampling design shall also be similar, with the establishment of 2 major (20m x 20 m) plots per transect, each with 4 to 8 subplots (pending the presence of herbaceous vegetation). The specific location of these plots shall be determined with the consent of the SFWMD after an initial site survey with porewater salinity, temperature, and the CCS tracer suite measurements as described above. However, along the three short eastern transects, initial site survey points shall be spaced approximately 100 to 200 m apart. The following shall be measured as previously described for freshwater wetlands: plant community composition, cover, canopy height, leaf litter production, and leaf biomass turnover; stage, surface water temperature, and conductivity; and soil temperature, porewater specific conductance, the CCS tracer suite, and nutrients. Additionally, dissolved sulfides shall be measured in saline wetland porewater. Twice a year (at the end of the wet and dry seasons), ten leaves/stems from each of the dominant species shall be randomly selected and collected from each plot along the transect. Leaf characteristics (i.e., leaf length, width, and thickness, water content) shall be measured prior to the leaves being dried and analyzed for C, N, and P contents, as well for $\delta^{13}C$. Changes in these plant characteristics over time and among plants within and among transects shall be analyzed for trends and differences.

The saline coastal portion of the reference transect within the Triangle Area (Figure 2-5) shall also include, at a minimum, 3 major plots and subplots and sampling of these subplots as described for the saline wetlands.

2.5.8 CCS Ecological Measurements

At the time when the transect surveys are conducted, CCS sampling to characterize nutrient concentrations in the sediments of CCS canals shall also be conducted to better understand ecological relationships in adjacent areas. Sampling shall be done along three transects extending from the three western marsh transects (yellow in Figure 2-5) to the three saline marsh transects east of the CCS (pink in Figure 2-5). Measurements shall include nutrients in porewater and bulk sediment. Along each of these transects, five sites shall be selected, including the eastern- and western-most canals. Sediment cores shall be collected two times per year with porewater analysis twice per year, and bulk sediment analysis once per year (as in wetland and Biscayne Bay sampling). Sample depths shall include surface (0-10 cm) and subsurface (40-50 cm) samples. Major dissolved macronutrients (TP, SRP, TKN, NO_X, NH_4, SiO_4, DOC), and micronutrients (Fe and trace metals) in porewater and total nutrients (TP, TN, TOC) and select elements (a subset of those listed in Table 2-1, established in consultation with the SFWMD after Plan adoption) in the sediments shall be measured.

2.5.9 Biscayne Bay and Card Sound

Ecological monitoring of Biscayne Bay and Card Sound shall focus on documenting benthic biota (submerged aquatic vegetation (SAV), benthic and epibenthic fauna), specific conductance to which these biota are exposed, and a CCS tracer suite to distinguish the extent of CCS connectivity to these conditions. Specific conductance and the CCS tracer suite initially shall be broadly surveyed as described above (see Section 2.5.3). Benthic surveys, and fish and invertebrate sampling, as specified in the Plan shall utilize results from existing monitoring programs within Biscayne Bay to the extent possible. Sample methodology for work in the Plan is consistent with other programs within Biscayne Bay and Card Sound, but is performed in locations near Turkey Point not sampled by the other programs. Data from these programs shall be used for assessment of reference area conditions.

Benthic surveys shall be made using a transect design to discern potential CCS effects as a function of distance from shore. A set of twelve fixed transects (black lines in Figure 2-5), each 2 km long, shall be sampled randomly (along each transect) twice per year. The transects shall be arrayed such that each set includes 4 transects approximately parallel to shore that are 0.5 km, 1.0 km, 2.0 km, and 4.0 km offshore. The array shall include 4 sets of these transects that project from the proposed saline wetland transects: one northern zone (offshore of the power plant), one central zone (offshore of the central CCS), one southern zone (offshore of the Sea Dade Canal - southeast CCS corner), and one reference set in northern Barnes Sound (starting north of Middle Key; in turquoise in Figure 2-5). Sampling shall be done to estimate the species composition, abundance and cover of benthic vegetation (submerged aquatic vegetation, SAV, including macroalgae) and large sessile fauna (e.g., corals and sponges), using the Braun–Blanquet methodology currently used in Florida Bay and Biscayne Bay by RECOVER and other groups (Fourqurean et al. 2001). For each transect and sampling event, 10 points shall be randomly selected, with measurements in 4 quadrats (0.25 m^2 each) per sample point. Sampling times shall be done twice per year, once during the months of March-May and once during the months of August-October.

SAV closer than 0.5 km shall be monitored using video analysis, as in Lirman et al. (2008) along the shoreline from the Florida City Canal to Card Point, plus along the shoreline of northern Barnes Sound from the Card Sound Bridge to Middle Key as a reference area. Surveys should coincide with the timing of the Braun-Blanquet surveys (2 times per year).

Nearshore benthic fauna (small fish and invertebrates, such as pink shrimp) are currently monitored by RECOVER elsewhere in Biscayne Bay and Card Sound (Figure 2-7), but not off the CCS north of Mangrove Point. This Monitoring Plan component shall fill this gap between Mangrove Point and Turkey Point, using the same methods (with 30 throw trap samples per sampling event, twice during the year in the wet season and dry season).

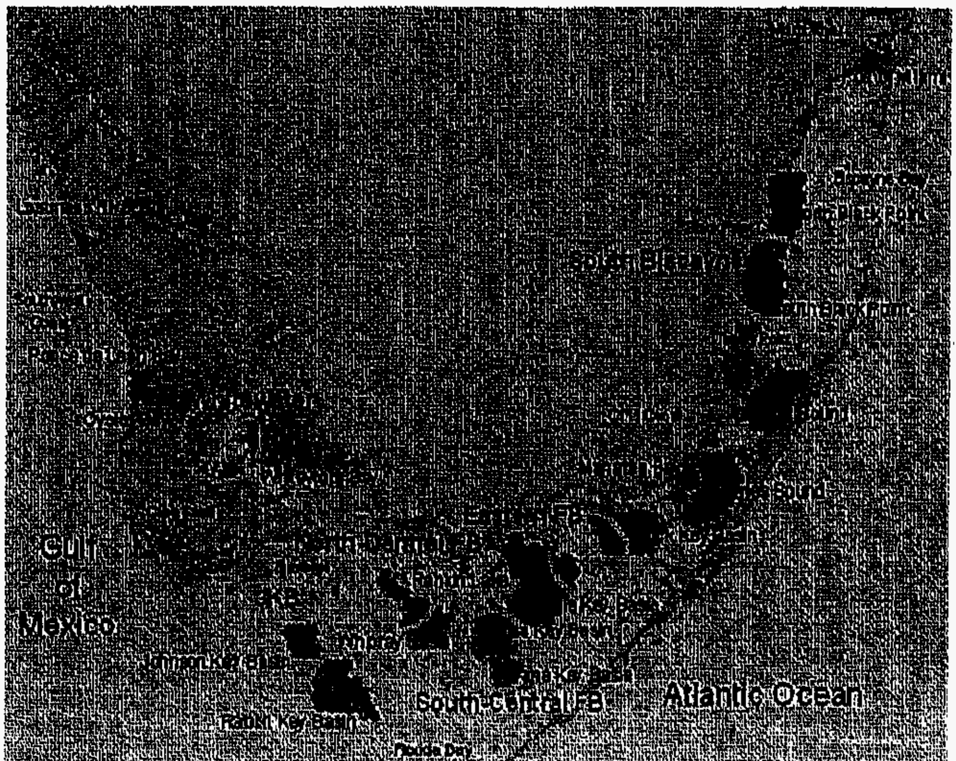

Figure 2-7. Fish and Invertebrate Assessment Network sample basins (in green), funded by RECOVER. (See, http://www.sfrestore.org/scg/scg_meetings/2008_meetings/092508/Pink%20Shrimp%20ASSESSMENT%202008.pdf).

Supporting information, needed to interpret ecological findings, shall be collected along transects and at fish and invertebrate sampling sites. Surface water specific conductance and temperature shall be measured at each site during each sampling event. For each benthic survey transect, light extinction shall be measured at two points per transect. Porewater specific conductance and temperature shall also be measured at each sampling point along these transects, with the CCS tracer suite measured at a subset of points (at least three per transect). Sampling depth shall reflect exposure within the seagrass root zone (upper 30 cm). Nutrients in porewater (as measured in the CCS and wetlands) shall be measured twice per year and bulk sediments shall be measured once per year at 3 sites per transect (as described in the Wetland sections). Seagrass leaf nutrients from the dominant species (likely turtle grass) along each transect shall also be analyzed once per year for total nutrient content (C, N, P per dry weight), as well as $\delta^{13}C$ and $\delta^{15}N$ ratios.

Table 2-6. Ecologic Monitoring: Transect Sampling.

Zone	Location(s) and number	Surface Water (SW) & Porewater (PW) Parameters	Biotic Parameters	Soil/ Sediment Parameters	Frequency	Description
Fresh Water Wetland	3 east-west transects, 3 (roughly) north-south transects, 1 reference transect (Figure 2-5). All with 3 spatial levels (20 m plots, 5 m and 1 m subplots; Figure 2-6)	SW: stage; temperature, and conductivity, PW: temperature, conductivity, tracer set, nutrients, boron	Plant community composition, cover, canopy height, productivity, leaf characteristics, C, N, P contents, $\delta^{13}C$	Nutrients (TOC,N,P), bulk density	Annual, bi-annual and once every three months depending on plot level (see text)	Additional parameters may be added
CCS	Along each of three transect lines within the CCS. Minimum of 5 sites per transect.	PW: temperature, conductivity, nutrients		Nutrients (C,N,P), bulk density, TOC trace elements	Once or twice per year consistent with timing of wetland transect samplings	Additional parameters may be added
Saline/ Coastal Wetland	Six transects plus reference transect (Figure 2-5). 3 spatial levels (20 m plots, 5 m and 1 m subplots; Figure 2-6)	SW: stage, temperature, conductivity PW: temperature, conductivity, CCS tracer suite, nutrients, and dissolved sulfide	Plant community composition, cover, canopy height, photosynthesis, leaf characteristics , C, N, P contents, $\delta^{13}C$	Nutrients (TOC,N,P), bulk density,	Annual, bi-annual and once every three months depending on plot level (see text	Additional parameters may be added
Biscayne Bay and Card Sound	For SAV and sessile benthic fauna, 4 sets of 4 transects (each 2 km long). Ten random sample points per transect. For nearshore 500 m zone, video SAV survey. For mobile epibenthic fauna, area between Mangrove and Turkey points, 30 stratified random points.	SW: temperature, conductivity, light extinction PW: temperature, conductivity, CCS tracer suite, nutrients	Benthic (SAV, coral, sponge) community composition and cover, salinity, temperature, seagrass leaf nutrients (C,N,P), $\delta^{13}C$, and $\delta^{15}N$, fish and invertebrate species composition and abundance	Nutrients (C,N,P), bulk density, TOC	Two times per year for biota and waters, one time per year for sediments.	Additional parameters may be added

Table 2-7. Ecologic Monitoring: Initial Characterization and Survey Sampling.

Zone	Type	Location(s) and number	Parameter(s)	Frequency	Description
Fresh Water and Saline Wetland	Resistivity Survey	At least as far west as Tallahassee Rd. and Card Sound Road south of the L-31E, at least as far north as the Florida City Canal, south to Card Sound	--	1	
	Porewater Survey	Spatially distributed within freshwater wetlands; minimum of 100 conductivity samples and 50 CCS tracer suite samples	Temperature, conductivity and CCS tracer suite, water level	1-2 times; initiate after Plan authorization	Additional parameters may be added after the first sampling event.
CCS	Resistivity Survey	Entire area of CCS	--	1	
Biscayne Bay	Resistivity Survey	Biscayne Bay south of Florida City Canal and Card Sound	--		
	Porewater Survey	Spatially distributed within 3 km of shore; minimum of 100 conductivity samples and 50 CCS tracer suite samples	Temperature, conductivity and CCS tracer suite	1-2 times; initiate after Plan authorization	Additional parameters may be added after the first sampling event.
All	Aerial Imaging	Entire area of interest	--	Pre- and post-Uprate per Plan specifications	

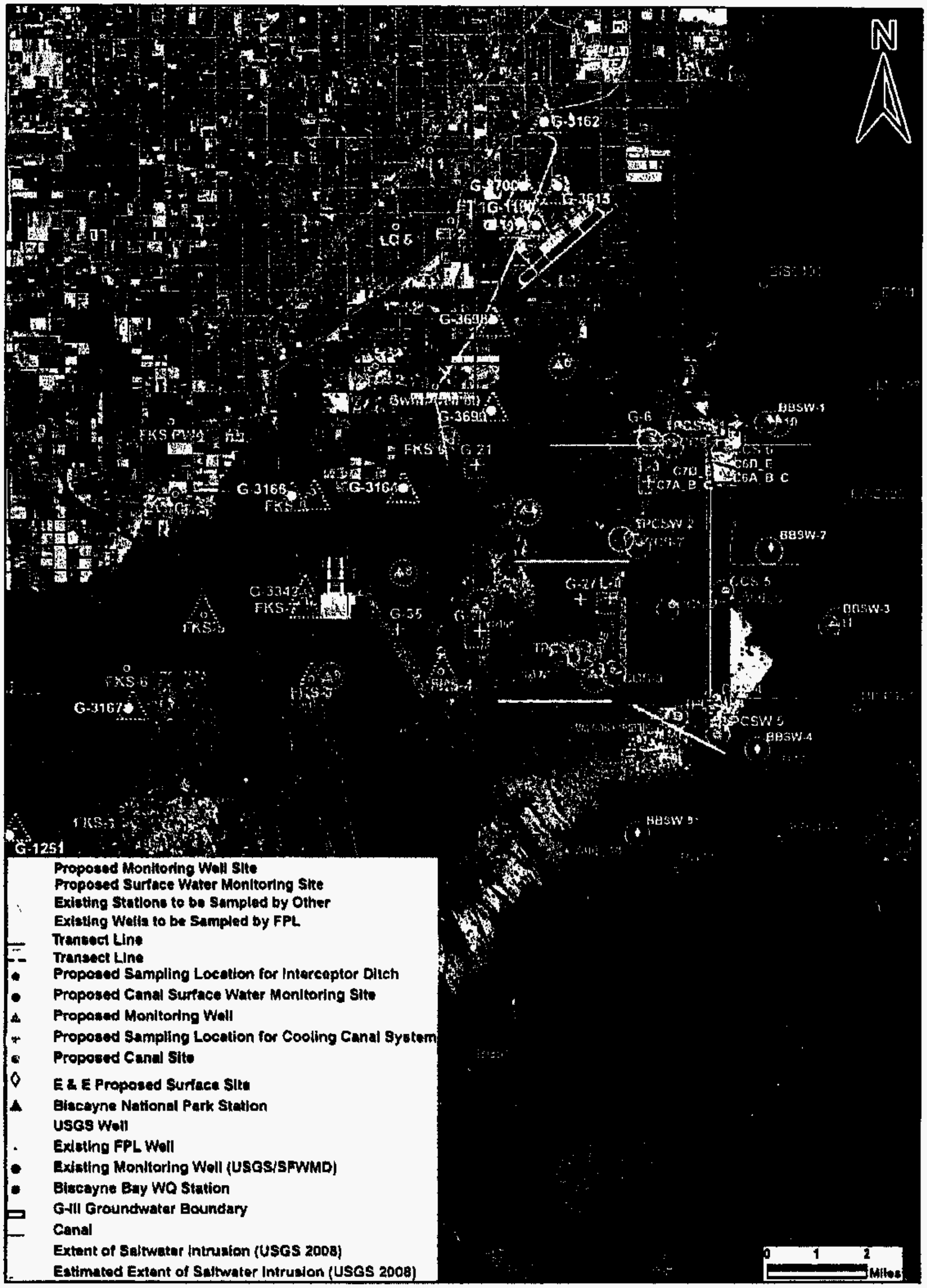

Figure 2-8. Existing and Proposed Monitoring Locations. (E & E need to update maps and locations)

3

Field Notifications Data Collection and Reporting

3.3 QUALITY ASSURANCE/QUALITY CONTROL (QA/QC) PLAN

Pursuant to Chapter 62-160 F.A.C., a QA/QC Plan shall be prepared and submitted for the Agencies approval within 45 days of this Plan's approval. The QA/QC Plan shall lay out the overall framework to ensure defensible monitoring results and quality reporting. The Plan shall outline procedures used in the field to install wells, manually collect samples, and conduct laboratory analysis. All data collected shall meet SFWMD and FDEP QA/QC requirements. More detailed information related to calibration and maintenance of probes and other automated instrumentation shall be provided. A major part of the QA/QC Plan shall describe data management procedures to ensure the data is properly recorded and reported.

Detection limits for each parameter in the Plan shall be listed in the QA/QC Plan for Agency approval.

Field measurements for salinity shall be made in accordance with the Standard Method 2520B using the Practical Salinity Scale of 1978 (PSS78) (APHA 1998). Since the PSS78 is accurate to a salinity range of 2 to 42, it will be necessary to use chloride and TDS data from laboratory measurements to validate salinity values exceeding 42. The QA/QC plan should include a methodology for performing these validations.

3.3.1 Field Event Notifications

The lead Agency personnel or their designated contractor shall be notified of all field events no later than five days prior to initiation of field events including but not limited to site surveys, well installation, and surface and groundwater sampling. During long-term events, such as well installation, the lead Agency shall be notified for subtasks, such as development and geophysical logging. Agency personnel shall have access onsite to observe field activities and provide copies of field generated data upon request. If field events are delayed, notification should be provided as soon as practical and include the revised field event schedule.

3.3.2 Modification Requests/Notifications

Minor modifications to the Plan, such as movement/adjustment of monitoring stations or locations over short distances due logistical constraints or to optimize monitoring, may be initiated by FPL or the Agencies in writing during Plan implementation. Modification requests by FPL shall be submitted within two months of implementation and must be approved by the Agencies prior to implementation.

3.3.3 Meetings

To facilitate communication and keep the Agencies apprised of the monitoring efforts and any significant findings, semi-annual meetings shall be held. Issues of concern or suggested improvements in the monitoring effort commensurate with focused objectives of the Conditions of Certification should be discussed.

3.1 DATA COLLECTION AND REPORTING

Detailed information shall be provided to enable the Agencies to understand potential physical, chemical, and possibly ecological impacts of water movement and/or interchanges between the CCS, surface water and groundwater. Data shall be submitted on a secure Web site and in the form of hard and electronic report copies. In accordance with the Conditions of Certification and unless stated otherwise in the Fifth Supplemental Agreement, electronic copies of all data and reports generated directly from this Monitoring Plan shall be provided to the SFWMD Director of Water Supply, Miami-Dade County Director of DERM, FDEP Director of the Southeast District Office, FDEP Siting Coordination Office Director, and Biscayne Bay Aquatic Preserve Manager.

Table 3-1 provides a summary of data collection efforts and frequency of collection.

Table 3-1. Sampling Frequency.

Sample Type	Automated Parameters	Electronic Frequency	Manual Parameters	Manual Frequency
CCS Water	Salinity[1], Conductivity, Temperature, Water Level	15 minutes	Salinity, Conductivity, Temperature, tracer suite and water quality parameters	Quarterly
Groundwater Monitoring Wells	Salinity[1], Conductivity, Temperature, Water Level	15 minutes	Salinity, Conductivity, Temperature, tracer suite and water quality parameters	Quarterly
Biscayne Bay Littoral Zone Surface Water	Salinity[1], Conductivity, Temperature, Water Level	15 minutes	Salinity, Conductivity, Temperature, tracer suite and water quality parameters	Quarterly
Canal Surface Water	Salinity[1], Conductivity, Temperature, Water Level	15 minutes	Salinity, Conductivity, Temperature, tracer suite and water quality parameters	Quarterly
Interceptor Ditch Control (Interceptor Ditch, L-31E, and CCS)	Salinity[1], Conductivity, Temperature, Water Level	15 minutes	Salinity, Conductivity, Temperature, tracer suite and water quality parameters	Quarterly
Ecological Monitoring	See Tables 2-6 and 2-7.			

[1] Salinity values calculated using the PSS78.

3.1 DATA COLLECTION

3.1.1 Automated Sample Collection

Proposed stations identified in Figures 2-1, 2-2, and 2-5 of this document shall be electronically monitored by FPL. All automated time-series specific conductivity, temperature, and water level data as discussed in Section 2 and provided in Table 3-2 shall be compiled from the remote locations through the use of telemetry. Each station shall have a stand-alone solar power supply, onsite data loggers (with storage capacity), and the appropriate sensors needed to monitor the parameters described in Table 3-2. Each data logger shall initially be programmed to collect the required data at 15-minute intervals (unless otherwise noted) starting at the top of the hour based on time at the atomic clock and maintained in Eastern Standard Time. The data loggers shall also not account for Daylight Savings Time, to retain consistency with SFWMD data collection efforts. Calibration of sensors shall be a function of the manufacturer's specifications. All sensors and equipment shall be maintained per the manufacturer's specifications.

Table 3-2. Proposed automated time-series data collection from surface and groundwater stations.

Parameter	Units
Temperature	Degrees (Celsius)
Level	Feet (1929 NGVD and in 1988 NAVD)
Specific Conductance	$\mu S\ cm^{-1}$
Salinity	psu

3.1.2 Manual Sample Collection

Data from efforts such as borehole logging, well and stage recorder surveying, manual water quality sampling, and biological monitoring, shall be recorded in field notebooks prior to transcription to an electronic database. As outlined in Section 2 and per Table 3-1, water quality samples shall be collected from groundwater wells, surface waters, and the CCS, as part of regular monitoring on a quarterly basis.

3.2 DATA REPORTING

3.2.1 Web Database

The data base shall be maintained and archived by FPL. This server shall be backed up and archived weekly to minimize the risk of data loss. The Agencies shall be given passwords to access the data 24 hours a day/7 days a week. A web master's contact information shall be clearly posted on the web page. The Web-based applications shall provide the following:

- Geologic and hydrogeologic data acquired during this investigation
- Well construction data and spreadsheets
- Downhole geophysical logs
- Geophysical surveys
- Water budget and load calculation
- Bathymetric survey
- Equipment calibration logs and maintained records
- Manual sampling COC's, field data sheets, laboratory analytical reports
- Summarized data shall include but is not limited to:
- Groundwater and surface water hydrographs
- Spreadsheet summaries and graphical representations of current and historical manual sample results
- Automated reports such as but is not limited to water level, temperature, specific conductivity and ID pump operations, meteorological monitoring
- Log of any plant operations change, system shut downs or deviations that might affect parameters in this investigation
- All results generated as a result of ecological monitoring, Sections 2.3.2 and 2.5, Geophysical Surveys
- Semi-annual and annual reports in PDF formats
- All other reports that pertain to this Monitoring Plan
- Aerial imaging results

If determined that additional information must be added or modified to enhance the Web site, FPL shall do this within 30 days.

3.2.2 Automated Data Reporting

The data generated from continuous electronic monitoring of meteorological, surface and groundwater stations and ID stage and pump operations shall be accessible real-time to the lead Agency; however, the raw data shall not become official until FPL has had a chance to conduct a Quality Assurance/Quality Control (QA/QC) review. This shall be done within 30 days of the date of collection. FPL shall provide electronic accessibility of the results to the SFWMD, FDEP, and DERM. All data shall be stored in a database maintained by FPL; this server shall be backed up and archived weekly to minimize the risk of data loss. The data shall be tabulated in downloadable Excel® or similar format, and where appropriate, graphically presented to allow monitoring of operations by FPL staff, quick review of time-series data variations, and sensor performance.

3.2.3 Manual Data Reporting

Data collected from manual sampling and monitoring shall be stored in a database maintained by FPL; this server shall be backed up and archived weekly to minimize the risk of data loss. Electronic copies of analytical data shall be provided simultaneously to FPL and the lead Agency, however, the data shall not become official until it has undergone a QA/QC review by FPL. A summary of QA/QC analytical results shall be posted on a secure Web site. While the length of time between collecting the data and posting it will vary depending on what is collected, FPL shall post the data within three months of collection or at minimum provide a status as to when the data shall be posted. The manual data shall be compiled with automated data into reports as outlined below. Data files shall be made electronically available to the Agencies.

Surveyor's Report

FPL shall obtain a licensed Florida surveyor to conduct detailed surveys at each location where monitoring is being done. The data collected from this effort shall be compiled and documented in a report that documents all data and techniques. The order of surveying shall be documented (1st, 2nd, or 3rd order).

Data collected from the survey of the groundwater well, surface water, and porewater sites should be documented. The data includes (Appendix C), but is not limited to: Latitude, Longitude, 1983 State Planar Coordinates North American Datum (NAD), Florida East zone, 1927 State Planar Coordinates NAD, Florida East zone, Natural Ground Surface Elevation: Elevation in 1988 North American Vertical Datum (NAVD); Elevation in 1929 National Geodetic Vertical Datum (NGVD); Elevation of bottom of surface water location; Elevation in 1988 NAVD; Elevation in 1929 NGVD; Monitor Well Top-of-Casing Elevation: Elevation in 1988 NAVD; Elevation in 1929 NGVD;

Elevation of any nearby standing surface water at the time of surveying. Electronic copy of field notes, electronic copy of all computation sheets, CORPSMET 95 files, site photographs, surveyor's report, benchmark sheets shall also be included.

3.2.3 Geology and Hydrogeology Report

Geologic and hydrogeologic data as outlined in this Monitoring Plan shall be collected to better understand the movement of water within the Biscayne aquifer, in the immediate vicinity of the CCS. This is relevant because subsurface conditions may influence the extent and rate of CCS water migration.

This report shall provide information on the lithology and hydrostratigraphy of the subsurface rocks and sediments of that area. Subsurface data collected from groundwater monitoring sites installed in the current and previous investigations (Unit 6 & 7 borings and APT's [near the footprint of new plant and radial collection borings and APT], will be placed in a hydrostratigraphic context that can be integrated into the developing karst hydrostratigraphic framework being developed by the USGS for Miami-Dade County (e.g., Cunningham et al. 2004; 2006a; 2006b; 2008]).

Agency personnel shall be allowed onsite to observe field activities and provided copies of field generated data upon request. The SFWMD will pre-approve well screen intervals prior to well construction.

Data collected during well installation (Section 2.3.1), including detailed lithologic logs, borehole geophysics, digital optical logs, initial induction logs, temperature and flowmeter logs, field water quality data, and well construction details shall be compiled and submitted to Agencies within 30 days of completion of each well. In addition, a summary of well drilling procedures, geophysical logging procedures, and instrumentation used shall be provided. Based on wells installed from this monitoring effort and other subsurface geologic data, scaled geologic cross sections, including macroporosity zone and geophysical log overlays, shall be generated and included in the report. This includes information from the induction logs, which reveal zones of saline water. Also a plan view map showing the location of significant features shall be included. The information generated from this report will enable a better understanding of the movement of groundwater in the area and will provide the basis for interpretation of tracer and water quality monitoring.

At the request of the SFWMD geophysical logs shall be provided electronically in a *.pdf and an *.las format.

Biscayne Bay Geophysical Survey Report

This electromagnetic resistivity survey is envisioned to aid in the vertical and horizontal delineation of the CCS water beneath Biscayne Bay. The geophysical survey cannot be fully implemented or at least results interpreted until the wells in Biscayne Bay are installed. Results from resistivity surveys shall be reported within six months of completion of a survey. Reports shall include a detailed description of methodology, maps showing survey track lines, and figures showing depth profiles of resistivity and any associated measurements along the track line. Best estimates of salinity or conductivity, derived from resistivity and all available salinity or conductivity data, shall be made with tabular documentation of data and calculations used for this estimate (in .xls or .xlsx format).

3.2.5 Water Budget Analysis Report

To estimate the rate at which water is transported or dispersed from the CCS, a water budget analysis shall be performed (Section 2.2.2). The results of the bathymetric survey, CCS characterization, water budget, and salt and ionic loads shall be included in the Water Budget Analysis Report. This report shall be generated following the collection of a year of groundwater, surface water and CCS water data and shall be prepared yearly. Following collection of data during the pre- and post-Uprate period, the salt and ionic loads shall be reassessed to see if there are any significant changes from the pre-Uprate period.

The water budget shall include a breakdown for each of the contributions. This includes, but is not limited to:

- Estimated losses/gains to surficial aquifer vertically
- Estimated losses/gains to Biscayne Bay
- Estimated losses/gains to CCS (rainfall, evaporation)
- Estimated losses/gains to surficial aquifer horizontally
- Estimated losses/gains to Biscayne Bay Surface Water
- Estimated losses/gains to Biscayne Bay Groundwater

3.2.6 Initial Ecological Condition Characterization Report

Initial information on salinity distribution shall be derived from porewater surveys of the freshwater and saline wetlands adjacent to the CCS and Biscayne Bay and Card Sound. Results from these surveys shall be detailed in a Report within one year of Plan approval. The Report shall provide a detailed description of all sampling and analysis methods, all data (including field and laboratory measurements, with QA/QC results, such as instrument blanks and calibrations), the GPS coordinates of all sites sampled, and a map showing site locations.

Climatic data from the previous month as recorded by onsite or nearby instrumentation (rain data, air temperature etc.) shall also be indicated in the Report. Results, including any calculations generated from the data, shall be provided in a spreadsheet (.xls or .xlsx format). Field observations shall also be recorded. The Report shall identify areas of CCS water connectivity with surface sediments and soils as indicated by the CCS tracer suite, and indicate potential ecological influence of the CCS.

3.2.7 Semi-Annual and Annual Comprehensive Monitoring Reports

Semi-annual and annual reports shall be provided to the Agencies during the pre-Uprate and post-Uprate monitoring periods. Comprehensive semi-annual monitoring reports shall be submitted for documentation of site conditions, data generated as part of Plan implementation including but not limited to, groundwater monitoring, surface water monitoring, CCS monitoring, and ecological monitoring as described in the Plan. The ecological component shall be a subsection of the Report and shall provide all data generated in the report period as indicated in the Ecological Monitoring (Section 2.5), including all field and laboratory measurements made, (with QA/QC results, such as instrument blanks and calibrations), the GPS coordinates of all sites sampled, and a map showing site sampling locations. The data and any calculations generated from the data shall be provided in electronic format (.xls or .xlsx format).

The report(s) should be submitted within 60 days of the completion of each monitoring season (wet and dry) and include quarterly and semi-annual monitoring results of the previous periods. The report(s) shall include a brief summary of the CCS operations and operational changes that result in changes in physical or chemical characteristics of cooling water effluent or flow rates. A description of monitoring activities, station modifications and station operational summaries, graphic summaries of electronic monitoring data with electronic data archives, spreadsheet summaries of physical parameters, sample results, sampling field forms and laboratory results, L-31E salinity profile reports, and monitoring well induction logging reports, and ID monitoring logs shall be included.

Results of the tracer study and integration with the water budget shall be provided to support estimates of 1) spatial extent of the plume and rate and direction of plume migration; 2) a comparison of tracer suite concentrations and other select chemical parameters within the cooling canal system to data from external surface and groundwater stations with an estimated percent contribution from waters originating from the CCS; and 3) a revised water budget that estimates the quantity of water and salt load that the CCS produced. The Report should include recommendations for installation of additional monitoring points or other Plan modifications if needed to complete the monitoring objectives.

The report(s) shall include a completeness evaluation of specific Plan objectives and recommendations for adjustments (additions or deletions) in the monitoring program along with rationales. An updated monitoring schedule shall be included in the report.

3.2.8 Comprehensive Pre-Uprate Report

A comprehensive pre-Uprate report shall be submitted for documentation of background conditions pre- and post-operation of the Uprate project. The report shall include summaries of data presentations included in semi-annual reports with trends analysis including incorporation of seasonal or other variations over the pre-Uprate monitoring period. The Report shall include a completeness evaluation of specific Plan objectives; recommendations for additional investigation if appropriate to meet the objectives, and recommendation for modification of ID operations if appropriate to meet the objectives of the revised Agreement.

3.2.9 Comprehensive Post-Uprate Report

A comprehensive Post-Uprate Report shall be submitted after the fourth year of post-Uprate monitoring. The report shall include summaries of data presentations included in post-Uprate semi-annual reports with trends analysis including incorporation of seasonal or other variations over the pre-Uprate monitoring period. The Report shall include a completeness evaluation of specific Plan objectives, recommendations for additional investigation if appropriate to meet the objectives, and recommendation for modification of ID operations if appropriate to meet the objectives of the revised Agreement. The Report shall include conclusions regarding change during the post-Uprate monitoring period. If the certification objectives of plume delineation is completed by the end of the four year period following the Uprate, and with Agency approval, tasks for plume delineation, including monitoring for tracers, may be discontinued.

4
Schedule

Table 4-1 shows an overall monitoring schedule. This schedule shall be updated semiannually and agreed jointly between FPL and the lead Agency with input from the other Agencies.

In addition, permits for installing monitoring wells and instrumentation in Biscayne National Park must be obtained and entities to conduct the work selected. It is envisioned that it will take at least six months to drill all wells, purchase instrumentation, set up the monitoring network and get it fully operational.

The Uprate project is expected by FPL to come online in the spring of 2012. There shall be a minimum of two years of data collection prior to the Uprate Project coming online (pre-Uprate monitoring). Pre-Uprate monitoring shall continue until the Uprate is operational. During this time, both automated and manual data collection shall be conducted.

Table 4-1. Initial and overall monitoring schedule. (Table needs to be updated based on this revision)

Year / Quarter / Month	[illegible]
Monitoring Network Set Up	
Characterize CCS Water	
Prepare QA/QC Plan	
Order and Install Instrumentation	
Install Wells	
Install Surface Water Stations	
Calibrate Instruments	
Obtain Park Permits for Monitoring Stations	
Set up Ecological Stations	
Conduct Electromagnetic Survey in Biscayne Bay	
Synoptic Sampling	
Conduct Automated Monitoring	
Conduct Manual Monitoring	
Conduct Ecological Monitoring	
Agency Briefing Meetings	
Submit Monitoring Reports	
Submit Geology and Hydrogeology Report	
Submit Electromagnetic Survey Report	
Submit Water Budget	
Review Data and Assess Need for Modifications to Plan	

Note: Schedule is to be updated every six months to reflect adaptive changes.

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Appendix A

FLORIDA DEP'S CONDITIONS OF CERTIFICATION IX AND X RELATED TO THE FPL TURKEY POINT POWER PLANT UPRATE

IX. Biscayne Bay Surface Water Monitoring

As proposed, the Turkey Point Units 3 and 4 uprate project may cause an increase in temperature and salinity in the cooling canal system. Field data is needed to determine impacts of the proposed changes in the Turkey Point cooling canal system on Biscayne Bay.

A. Within 180 days following certification of Units 3 & 4, FPL shall submit a Biscayne Bay Surface Water Monitoring Plan (Plan) pursuant to Chapter 62-302, F.A.C. to the DEP Southeast District Office for review and approval. The Plan shall include, at a minimum, the following components:

1. salinity and temperature monitoring within the surface waters of the Bay, including the Biscayne Bay Aquatic Preserve; (Specific parameters to be measured, including specific conductance and temperature, shall be sampled in accordance with Chapter 62-160, F.A.C.);
2. a minimum of five monitoring stations located near shore in the vicinity of the Turkey Point Plant; and 3. specific monitoring locations, sampling frequencies and methods, and specific parameters to be monitored.
3. specific monitoring locations, sampling frequencies and methods, and specific parameters to be monitored.

B. This monitoring data shall be compared to data using compatible monitoring instrumentation already in place in Biscayne Bay.

C. FPL shall continue the monitoring of salinity and temperature in the cooling canals under its industrial waste water facility permit.

D. If the Department determines that the pre- and post-Uprate salinity and temperature monitoring data indicate potential adverse changes in the surface water in Biscayne Bay, then the Department may propose additional measures to evaluate or to abate such impacts to Biscayne Bay.

E. The Plan, including monitoring locations, shall be approved prior to implementation. The Department shall indicate its approval or disapproval of the submitted Plan within 90 days of the originally submitted information. In the event that the Department requires additional information for the licensee to complete, and the Department to approve the Plan, the Department shall make a written request to the licensee for additional information no later than 30 days after receipt of the submitted information. Any changes to the approved Surface Water Monitoring Plan shall be approved by Coastal and Aquatic Managed Area personnel in consultation with other FDEP personnel. [62-160, 62-302, 62-302.700, 62-520.600, F.A.C.]

X. Surface Water, Groundwater, Ecological Monitoring

This is a consolidated condition agreed upon by three Agencies, Department of Environmental Protection (DEP), Miami-Dade County Department of Environmental Resource Management (DERM) and the South Florida Water Management District (SFWMD). This consolidated condition sets forth the framework for new monitoring and, as may be needed, abatement or mitigation measures, for approval of FPL's Turkey Point Units 3 and 4 Uprate Application. Specific monitoring and potential modeling parameters will be identified and implemented pursuant to a monitoring plan as part of a supplemental agreement between FPL and the SFWMD as described below.

A. In addition to the monitoring framework set forth in this consolidated condition, within 180 days after Certification, FPL shall execute a SFWMD approved Fifth Supplemental Turkey Point Agreement ("Fifth Supplemental Agreement") to the original 1972 Agreement between FPL and the SFWMD pertaining to FPL's obligation to monitor for impacts of the Turkey Point cooling canal system on the water resources of the SFWMD in general and the facilities and operations of the SFWMD (the "Agreement"). Subject to the SFWMD's approval, FPL shall also amend the Agreement's Revised Operating Manual as referenced in paragraph C. "Monitoring Provisions" (the "Revised Plan") of the Fourth Supplemental Agreement, dated July 15, 1983. The Revised Plan shall be incorporated into the Fifth Supplemental Agreement and shall include assessment of potential impacts to surface water and groundwater including wetlands, as needed, in the vicinity of the cooling canal system. The specific monitoring boundaries shall be determined as part of the Revised Plan.

B. The Revised Plan shall be designed to be in concurrence with other existing and ongoing monitoring efforts in the area and shall include but not necessarily be limited to, surface water, groundwater and water quality monitoring, and ecological monitoring to:

1. delineate the vertical and horizontal extent of the hyper-saline plume that originates from the cooling canal system and to characterize the water quality including salinity and temperature impacts of this plume for the baseline condition;

2. determine the extent and effect of the groundwater plume on surface water quality as a baseline condition; and
3. detect changes in the quantity and quality of surface and groundwater over time due to the cooling canal system associated with the Uprate project. The Revised Plan shall include installation and monitoring of an appropriate network of wells and surface water stations. The Revised Plan shall be approved by the SFWMD in consultation with the DEP Office of Coastal and Aquatic Managed Areas, the DEP Southeast District Office and DERM.

C. FPL shall transmit electronic copies of all data and reports required under the Fifth Supplemental Agreement and the Revised Plan in accordance with timeframes as approved in the Fifth Supplemental Agreement to:

SFWMD, Director, Water Supply (or alternative transmittal procedures to be described in the Fifth Supplemental Agreement);
Miami-Dade County, Director, DERM; DEP, Director, Southeast District Office;
DEP Siting Coordination Office;
DEP, Director, Biscayne Bay Aquatic Preserve Manager.

D. If the DEP in consultation with SFWMD and DERM determines that the pre- and post-Uprate monitoring data: is insufficient to evaluate changes as a result of this project; indicates harm or potential harm to the waters of the State including ecological resources; exceeds State or County water quality standards; or is inconsistent with the goals and objectives of the CERP Biscayne Bay Coastal Wetlands Project, then additional measures, including enhanced monitoring and/or modeling, shall be required to evaluate or to abate such impacts. Additional measures include but are not limited to:

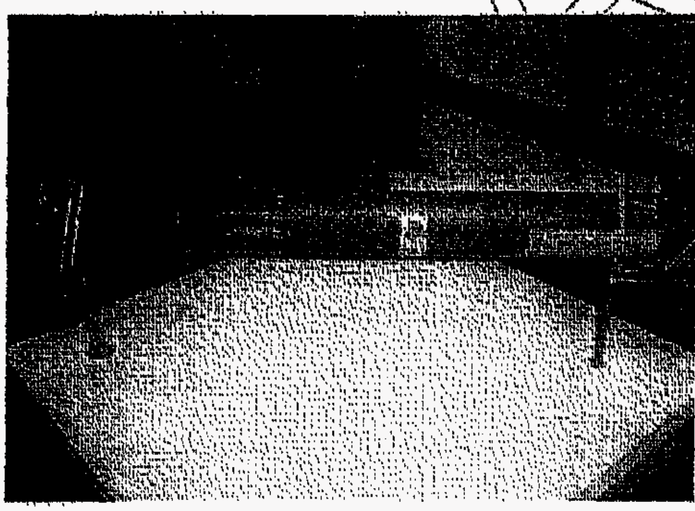
1. the development and application of a 3-dimensional coupled surface and groundwater model (density dependent) to further assess impacts of the Uprate Project on ground and surface waters; such model shall be calibrated and verified using the data collection during the monitoring period;
2. mitigation measures to offset such impacts of the Uprate Project necessary to comply with State and local water quality standards, which may include methods and features to reduce and mitigate salinity increases in groundwater including the use of highly treated reuse water for recharge of the Biscayne aquifer or wetlands rehydration;
3. operational changes in the cooling canal system to reduce any such impacts; and/or 4. other measures to abate impacts as may be described in the Revised Plan.

[Sections 373.016, 373.223, F.S.; Rules 40E-4.011, 40E-4.301, 40E-4.302, F.A.C.; Sections 62-302 and 62-520, F.A.C.; Section 24-42, Code of Miami-Dade County, Miami-Dade County Comprehensive Development Master Plan (CDMP) Land Use Element, Conservation Element, Intergovernmental Coordination Element, Coastal Management Element.]

Appendix B

NEAR SHORE SONDE DEPLOYMENT METHODS

The near shore sites, or mangrove sites, have sondes deployed to measure salinity using differing methods. This is due to the extremely shallow water at these locations, as well as the composition of the bottom substrate. Normally the sondes are deployed in a vertical position attached to a mooring pin, which has been cemented in place by drilling a hole in the bay floor. However at the mangrove sites there is insufficient water for vertical deployments, so the instruments are deployed horizontally~ and the bottom is composed mainly of mud which is unsuitable for drilling. Therefore, the instruments are deployed affixed to cement paving slabs, which have been drilled in 2 places at opposing comers and fitted with stainless steel eyebolts, that settle into the mud with the eyes of the eyebolts well above the bottom, and in the water column. The sonde is then locked to one of the eyebolts and fastened securely to both using nylon tie-wraps. This maintains a constant horizontal position, which will remain beneath the water surface even at low tide. This positioning also provides ample space for an additional sonde to be mounted simultaneously for concurrent sampling and overlapping data at deployment and retrieval times to ensure quality control. Per instruction by YSI personnel, the instruments are oriented in a way such that the sensor's hole is not facing directly down which could cause air bubbles to accumulate and skew the salinity data.



Appendix C

SURVEY PARAMETERS COLLECTED DURING GROUNDWATER WELL INSTALLATION

Data collected from the survey of the groundwater well, surface water and porewater sites. The data includes, but is not limited to:

- Latitude
- Longitude
- 1983 State Planar Coordinates North American Datum (NAD), Florida East zone
- 1927 State Planar Coordinates NAD, Florida East zone
- Natural Ground Surface Elevation
- Elevation in 1988 North American Vertical Datum (NAVD)
- Elevation in 1929 National Geodetic Vertical Datum (NGVD)
- Elevation of bottom of surface water location
- Elevation in 1988 NAVD
- Elevation in 1929 NGVD
- Monitor Well Top-of-Casing Elevation
- Elevation in 1988 NAVD
- Elevation in 1929 NGVD
- Elevation of any nearby standing surface water at the time of surveying (15 feet radius from site)

Appendix D

SPECIAL REQUIREMENTS FOR AN ELECTRO-MAGNETIC INDUCTION WELL (USGS)

In general the well should meet normal State or Federal Regulations for monitoring wells. USGS publication WRIR-96-4233 (http://water.usgs.gov/owq/pubs/wri/wri964233/) provides general guidelines for the installation of monitoring wells used to evaluate water quality. In addition to these general guidelines there are some special requirements needed if the well is going to be logged using an electromagnetic induction probe:

Casing material PVC: metal casing will interfere with the log.

Well Screen PVC: metal screens will interfere with the log. Slotted screen generally works but opening size is important. Sand from the aquifer can fill the well if the holes are too big.

Well diameter generally 2" to 6": USGS is currently logging wells 2" to 6" in diameter. For shallow wells, 2" usually works fine. For deep wells (>150 feet), the USGS suggests 3" or 4" well diameters to make sure the probe does not get stuck. The probe is most sensitive to differences in conductivity within an 8" to 40" donut-shaped radius around the well. 2 inch wells are generally fine but in very deep wells or long screened wells, the USGS has had difficulty getting the probe down the hole because of bends or distortions in the well casing so going with a 3 or 4" diameter well might provide better success in deep wells.

Depth extending to the base of the Biscayne aquifer is generally best because this allows us to evaluate changes throughout the zone of interest. Salinity is usually but not always highest at the base of the aquifer so this is generally a good depth to set the open interval. But the driller needs to be careful not over shoot the bottom of the aquifer.

If the monitoring well is to be used for detecting "up-coning" directly beneath a wellfield there are alternate strategies. If nothing but fresh water is found as drilling, it would be good to finish the well at the base of the aquifer. Future upconing would most likely begin at or near the base of the aquifer.

If salt water is found when drilling one can: (1) Stop drilling and screen the well at this depth so that one can monitor the chloride level at this depth or (2) Keep drilling to the base of the aquifer and complete the well at this depth to evaluate the full thickness of encroachment and maximum salinity. This would allow one to determine if seawater is encroaching preferentially through just one zone or throughout the depth of aquifer. Either way induction logging can help detect future up coning. With option 2 one would learn more about what is happening in the aquifer, but with option 1 one is able to obtain a precise chloride value in mg/l.

Open Interval 5 to 10 feet. The idea of a short screen length is to be able to sample a discrete interval and avoid the effects of flow within the borehole.

Chloride Sampling: It is generally good to collect water chloride samples during drilling to determine if encroached seawater is present.

Annular Seal Neat Cement is best. Bentonite may interfere with the log, but some sort of seal just above the filter pack is necessary to prevent the cement from infiltrating the filter packer. Very fine sand might work, or bentonite might be required.

Hole Less than 8 inches: One would want to avoid disturbing aquifer materials beyond the radius that the probe is insensitive to, which is 8 inches. It would also be good to try to clear up the hole prior to well installation. If there is a lot of mud or muddy water in the hole the first few logs might detect this. Do not use salty or electrically conductive drilling fluid.

Manhole cover metal is OK at the very top of well but no metal should be used down the hole or on the casing.

Well centralizers ONLY OK if non metallic, even the screws used for well centralizers have caused us problems.

Finish Flush Mounted, this is usually best because the logging requires setting a tripod over the well.

Well nests Avoid Metal in adjacent wells -- If wells are very close together and one has a metal object in it, this can affect the log in the other well.

Other Logs

Additional logs are a plus, and digital borehole images, gamma, flow logs, lithologic logs, well completion diagrams, caliper, and magnetic susceptibility could be invaluable when one sees changes occurring above the base of the aquifer and wonder why. These logs also help one ensure that one has set the open interval at the correct depth. In the past, wells have been put in too deep or too shallow. These wells do not provide the quality of data desired.

A geologist should oversee well drilling and well completion. The geologist should collect samples and create a lithologic log and make sure that careful well depth and material depth measurements are collected. The geologist should provide these logs to be used in conjunction with the induction logs.

Joints Threaded flush joint casing with seals. This prevents leakage from zones above the screened interval. This leakage could dilute samples and this could cause one to believe the water at the base of the aquifer is less saline than it really is.

Filter Pack: Grain size should be sufficient to keep the fine material in the aquifer from filling the well.

Depth Measurements: The depth of the well, the top of the screen should be carefully determined and recorded. The depth, to the top of the filter pack and the top of all annual seals, should be carefully measured. This is to ensure that no bridging occurred and that the screen is completely covered by the filter pack.

Well development: The well should be developed to clear and consolidate the filter pack. This also needs to be done to ensure that cement did not seep into the filter pack and clog it, and to verify that the well is not in an impermeable zone, which may happen if it is drilled below the base of the aquifer.

Station	Proposed or Existing Station	Automated Yes/No (Reporting Frequency)	Automated Sampling Parameters	Manual Sampling Parameters
Cooling Canal System (CCS)				
CCS-1 through CCS -7	Proposed	Yes (15-min intervals)	Specific conductance, temp, water level (pressure) at top and bottom at six stations and at bottom for one shallow station	Quarterly for field parameters, CCS tracer parameters, major ions, TDS, nutrients, silicate, chlorophyll-a and pheophytin. Also gross alpha semi-annually for one year.
CCS Thermal Anomaly (1 location)	Proposed	NA	NA	Initially once for field parameters, CCS tracer parameters, major ions, TDS, trace elements, nutrients, chlorophyll-a and pheophytin.
CCS	Proposed	Daily	Three meteorologic stations, three flow stations.	One-time bathymetry to be coupled to water levels, ions and elements for annual water budget calculations.
Canals Around Turkey Point				
TPCSW-1 through TPCSW-5	Proposed	Yes (15-min intervals)	Specific conductance, temp, water level (pressure) at top and bottom	Quarterly for field parameters, CCS tracer parameters, major ions, TDS, nutrients, silicate chlorophyll-a and pheophytin.
TPCSW-6	Proposed	NA	NA	
Biscayne Bay Surface Water				
BBSW-1 through BBSW-5	Proposed	Yes (15-min intervals)	Specific conductance, temp, water level (pressure) near bottom	Quarterly for field parameters, CCS tracer parameters, major ions, TDS, nutrients, silicate, chlorophyll-a and pheophytin.
BNP Stations – BISC08B, BISC12B, BISC13S	Existing	Yes (15-min intervals)	Specific conductance and temp collected by BNP.	NA
Groundwater Wells				
L-3,L-5, G-21 and G-28	Existing	No	NA	Quarterly for field parameters, CCS tracer parameters, major ions, and TDS. Also nutrients in all wells semi-annually.
USGS and FKAA Wells (note A below)	Existing	No	NA	Chloride data collected by others.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 12
COMPANY Florida Power & Light Company (Direct)
WITNESS R. R. Labauve (RRL-7) (Previously RRL-3)
DATE 11/02/09

Station	Proposed or Existing Station	Automated Yes/No (Reporting Frequency)	Automated Sampling Parameters	Manual Sampling Parameters
Well Clusters (TPGW-1 through TPGW -14 (3 wells per cluster)	Proposed (11 on land and 3 in Bay)	Yes (15-min intervals)	Specific conductance, temp, water level (pressure) in each well	Quarterly for field parameters, CCS tracer parameters, major ions, TDS, Also trace elements initially in 4 well clusters semi annually for one year and nutrients in all wells semi-annually.
Geophysical Survey				
Wetlands west of CCS	Proposed	No	NA	One-time aerial resistivity survey.
CCS	Proposed	No	NA	
Biscayne Bay	Proposed	No	NA	One wet and dry season survey either via boat/aerially.
Interceptor Ditch				
ID-1 through ID-3	Existing	Yes (15-min intervals)	Specific conductance, temp, water level (pressure) at top and bottom	Quarterly for field parameters, CCS tracer parameters, major ions, TDS, nutrients, silicate, chlorophyll-a and pheophytin.
Ecological Monitoring				
Aerial mapping (all areas of interest)	Proposed	No	NA	Once pre-Uprate, once post-Uprate.
Freshwater Wetlands	7 transects (28 plots)	No	NA	Vegetation composition, canopy height, leaf nutrients, isotopes, productivity once to four times a year . Conductivity, temperature, stage and CCS tracer parameters measured 4x/year, nutrients measured 2x/year.
BB Mangroves	7 transects (14 plots)	No	NA	
Sub-tidal Zone	16 transects (640 25-cm^2 plots)	No	NA	Benthic, invertebrate and fish composition one to four times a year. Conductivity, temperature, stage and CCS tracer parameters measured 4x/year, seagrass nutrients and isotopes measured 2x/year.
CCS	15 sites	No	NA	Sediment cores collected for nutrients and select elements in porewater (2x/year) and bulk sediment (1x/year) at two depths.
Porewater survey	200 points proposed	No	NA	Temperature, conductivity for 100 points each in Freshwater Wetlands and Biscayne Bay (within 3 km of shore). Subset of 30 samples per location for CCS tracer parameters.

<u>Key</u>:

BB = Biscayne Bay
BBSW = Biscayne Bay Surface Water
BNP = Biscayne National Park
CCS = Cooling Canal System
FKAA = Florida Keys Aqueduct Authority
ID = Interceptor Ditch
SFWMD = South Florida Water Management District
TDS = Total Dissolved Solids
TPCSW = Turkey Point Canal Surface Water
TPGW = Turkey Point Groundwater
USGS = United States Geologic Survey

<u>Notes</u>: A – Supplemental wells include but are not necessarily limited to G-1251, G-1630, G3167, FKS-3, FKS-4, FKS-5, FKS-7, FKS-8, FKS-9, G-3342, G-3166, G-3164, G-3699, G-3698, G-1179, G-1180, G-3700, G-3615, G-3162 and were selected based on location and/or well depth and/or screen interval. Wells can be sampled for other parameters if deemed appropriate as part of adaptive monitoring.

APPENDIX II

ENVIRONMENTAL COST RECOVERY

EXHIBITS OF
RANDALL R. LABAUVE

RRL-8	NESHAP ICR Public Notice
RRL-9	Electric Utility Steam Generating Unit Hazardous Air Pollutant Information Collection Effort Burden Statement Part B
RRL-10	Florida Department of Environmental Protection (FDEP) Industrial Wastewater Facility Permit Number FL0001473 for Plant Cape Canaveral (PCC)
RRL-11	PCC Manatee Protection Plan (MPP)
RRL-12	U.S. Fish and Wildlife Service (USFWS) letter to FPL
RRL-13	Florida Fish and Wildlife Conservation Commission's (FWC) "FWC Staff Report For Florida Power and Light Company – Cape Canaveral Energy Center (CCEC)"
RRL-14	Manatee Heating System Conceptual Location of Pumps and Heater

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 090007-EI EXHIBIT 13

COMPANY Florida Power & Light Company (Direct)

WITNESS R. R. Labauve (RRL-8) (Previously RRL-4)

DATE 11/02/09

local and Tribal governments, the general public and international community to comment on the scope of the EIS, including identification of reasonable alternatives and specific issues to be addressed.

DOE will hold public scoping meetings from 5:30 p.m.–9:30 p.m. on the following dates and locations:

- July 21, 2009 Two Rivers Convention Center, 159 Main Street, Grand Junction, CO 81501.
- July 23, 2009 Embassy Suites Kansas City—Plaza, 220 West 43rd Street, Kansas City, MO 64111.
- July 28, 2009 Clarion Hotel and Conference Center, 1515 George Washington Way, Richland, WA 99352.
- July 30, 2009 North Augusta Municipal Center, 100 Georgia Avenue, North Augusta, SC 29841.
- August 4, 2009 El Capitan Resort, 540 F Street, Hawthorne, NV 89415.
- August 6, 2009 James Roberts Civic Center, 855 E. Broadway, Andrews, TX 79714.
- August 11, 2009 Shilo Inn/O'Callahans Convention Center, 780 Lindsay Blvd., Idaho Falls, ID 83402.

Additional details on the scoping meetings will be provided in local media and at *http://www.mercurystorageeis.com*.

At each scoping meeting, DOE plans to hold an open house one hour prior to the formal portion of the meetings to allow participants to register to provide oral comments, view informational materials, and engage project staff. The registration table will have an oral comment registration form as well as a sign up sheet for those who do not wish to give oral comments but who would like to be included on the mailing list to receive future information. The public may provide written and/or oral comments at the scoping meetings.

Analysis of all public comments provided during the scoping meetings as well as those submitted as described in ADDRESSES above, will be considered in helping DOE further develop the scope of the EIS and potential issues to be addressed. DOE expects to issue a Draft EIS in the fall of 2009.

Issued in Washington, DC, on June 24, 2009.

Scott Blake Harris,

General Counsel.

[FR Doc. E9–15704 Filed 7–1–09; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Basic Energy Sciences Advisory Committee

AGENCY: Department of Energy, Office of Science.

ACTION: Notice of open meeting.

SUMMARY: This notice announces a meeting of the Basic Energy Sciences Advisory Committee (BESAC). Federal Advisory Committee Act (Pub. L. 92–463, 86 Stat. 770) requires that public notice of these meetings be announced in the Federal Register.

DATES: Thursday, July 9, 2009, 8:30 a.m.–5:30 p.m., and Friday, July 10, 2009, 8:30 a.m. to 12 noon.

ADDRESSES: Bethesda North Marriott Hotel and Conference Center, 5701 Marinelli Road, North Bethesda, MD 20852.

FOR FURTHER INFORMATION CONTACT: Katie Perine; Office of Basic Energy Sciences; U. S. Department of Energy; Germantown Building, Independence Avenue, Washington, DC 20585; Telephone: (301) 903–6529.

SUPPLEMENTARY INFORMATION: *Purpose of the Meeting:* The purpose of this meeting is to provide advice and guidance with respect to the basic energy sciences research program.

Tentative Agenda: Agenda will include discussions of the following:

- News from Office of Science/DOE;
- News from the Office of Basic Energy Sciences;
- Report from the New Era Subcommittee's Photon Workshop;
- Energy Frontier Research Center Update;
- COV Report for Materials Science and Engineering Division;
- New BESAC Charge.

Public Participation: The meeting is open to the public. If you would like to file a written statement with the Committee, you may do so either before or after the meeting. If you would like to make oral statements regarding any of the items on the agenda, you should contact Katie Perine at 301–903–6594 (fax) or *katie.perine@science.doe.gov* (e-mail). Reasonable provision will be made to include the scheduled oral statements on the agenda. The Chairperson of the Committee will conduct the meeting to facilitate the orderly conduct of business. Public comment will follow the 10-minute rule. This notice is being published less than 15 days before the date of the meeting due to programmatic issues that had to be resolved.

Minutes: The minutes of this meeting will be available for public review and copying within 30 days at the Freedom of Information Public Reading Room; 1E–190, Forrestal Building; 1000 Independence Avenue, SW.; Washington, D.C. 20585; between 9 a.m. and 4 p.m., Monday through Friday, except holidays.

Issued in Washington, DC, on June 30, 2009.

Rachel M. Samuel,

Deputy Committee Management Officer.

[FR Doc. E9–15779 Filed 7–1–09; 8:45 am]

BILLING CODE 6450–01–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OAR–2009–0234; FRL–8925–7]

Agency Information Collection Activities: Proposed Collection; Comment Request; Information Request for National Emission Standards for Coal- and Oil-fired Electric Utility Steam Generating Units; EPA ICR No. 2362.01

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act (PRA) (44 U.S.C. 3501 *et seq.*), this action announces that EPA is planning to submit a request for a new Information Collection Request (ICR) to the Office of Management and Budget (OMB). Before submitting the ICR to OMB for review and approval, EPA is soliciting comments on the proposed information collection as described below.

DATES: Comments must be submitted on or before August 31, 2009.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2009–0234, by one of the following methods:

- *www.regulations.gov:* Follow the on-line instructions for submitting comments.
- E-mail: *a-and-r-docket@epa.gov*.
- Fax: (202) 566–1741.
- Mail: Air and Radiation Docket and Information Center, Environmental Protection Agency, Mailcode: 2282IT, 1200 Pennsylvania Ave., NW., Washington, DC 20460.
- Hand Delivery: Air and Radiation Docket and Information Center, U.S. EPA, Room 3334, EPA West Building, 1301 Constitution Avenue, NW., Washington, DC. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. EPA–HQ–OAR–2009–0234. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *www.regulations.gov*, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *www.regulations.gov* or e-mail. The *www.regulations.gov* Web site is an "anonymous access" system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *www.regulations.gov* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional information about EPA's public docket, visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.*

FOR FURTHER INFORMATION CONTACT: William Maxwell, Energy Strategies Group, Sector Policies and Program Division, (D243–01), Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–5430; fax number: (919) 541–5450; e-mail address: *maxwell.bill@epa.gov.*

SUPPLEMENTARY INFORMATION:

How Can I Access the Docket and/or Submit Comments?

EPA has established a public docket for this ICR under Docket ID No. EPA–HQ–OAR–2009–0234, which is available for online viewing at *www.regulations.gov*, or in-person viewing at the Air and Radiation Docket in the EPA Docket Center (EPA/DC), EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC. The EPA/DC Public Reading Room is open from 8 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Reading Room is 202–566–1744, and the telephone number for the Air and Radiation Docket is 202–566–1742.

Use *www.regulations.gov* to obtain a copy of the draft collection of information, submit or view public comments, access the index listing of the contents of the docket, and to access those documents in the public docket that are available electronically. Once in the system, select "search," then key in the docket ID number identified in this document.

What Information Is EPA Particularly Interested in?

Pursuant to PRA section 3506(c)(2)(A), EPA specifically solicits comments and information to enable it to:

(i) Ealuate whether the proposed collection of information is necessary for the proper performance of the functions of the Agency, including whether the information will have practical utility;

(ii) Evaluate the accuracy of the Agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

(iii) enhance the quality, utility, and clarity of the information to be collected; and

(iv) minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated electronic, mechanical, or other technological collection techniques or other forms of information technology (*e.g.*, permitting electronic submission of responses).

What Should I Consider When I Prepare My Comments for EPA?

You may find the following suggestions helpful for preparing your comments.

1. Explain your views as clearly as possible and provide specific examples.
2. Describe any assumptions that you used.
3. Provide copies of any technical information and/or data you used that support your views.
4. If you estimate potential burden or costs, explain how you arrived at the estimate that you provide.
5. Offer alternative ways to improve the collection activity.
6. Make sure to submit your comments by the deadline identified under DATES.
7. To ensure proper receipt by EPA, be sure to identify the docket ID number assigned to this action in the subject line on the first page of your response. You may also provide the name, date, and Federal Register citation.

What Information Collection Activity or ICR Does This Apply to?

Affected entities: Entities potentially affected by this action are coal- and oil-fired electric utility steam generating units that emit hazardous air pollutants (HAP). Hazardous air pollutant means any pollutant listed pursuant to Clean Air Act (CAA) section 112(b). CAA section 112(a)(8) defines an electric utility steam generating unit as

> * * * any fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is also considered a utility unit.

Title: Information Collection Effort for Coal- and Oil-fired Electric Utility Steam Generating Units.

ICR numbers: EPA ICR No. 2362.01.

ICR status: This ICR is for a new information collection activity. An Agency may not conduct or sponsor, and a person is not required to respond to, a collection of information, unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in title 40 of the CFR, after appearing in the Federal Register when approved, are listed in 40 CFR part 9, are displayed either by publication in the Federal Register or by other appropriate means, such as on the related collection instrument or form, if applicable. The display of OMB control numbers in certain EPA regulations is consolidated in 40 CFR part 9.

Abstract: To obtain the information necessary to identify and categorize all coal- and oil-fired electric utility steam generating units potentially affected by the CAA section 112(d) standard, this ICR will solicit information from all potentially affected units under authority of CAA section 114. EPA intends to provide the survey in electronic format; however, written responses will also be accepted. The survey will be submitted to all facilities identified as being coal- or oil-fired electric utility steam generating units through databases available to the Agency. EPA envisions allowing recipients 3 months to respond to the survey. To further define the emission level being achieved by average of the top performing 12 percent of similar sources for the existing population, this ICR requires that certain units conduct emission testing concurrent with the survey. EPA envisions allowing recipients 6 months to respond to the emission testing requirement.

EPA estimates the cost of the information collection will be 100,370 hours and $104,807,458.

On December 20, 2000 (65 FR 79825, 79831), EPA added coal- and oil-fired electric utility steam generating units to the list of source categories under section 112(c). The CAA requires EPA to establish National Emission Standards for Hazardous Air Pollutants (NESHAP) for the control of HAP from both existing and new coal- and oil-fired electric utility steam generating units. Section 112(d) provides that for major sources, EPA must establish emission standards that reflect the maximum degree of reduction in emissions of HAP that is achievable, taking into consideration the cost of achieving the emission reduction, any non-air quality health and environmental impacts, and energy requirements. This level of control is commonly referred to as the "maximum achievable control technology" (MACT). The minimum level of emission reduction that the MACT standards must achieve is known as the "MACT floor," as defined under CAA section 112(d)(3). The MACT floor for existing sources is the emission limitation achieved by the average of the best-performing 12 percent of existing sources in the category or subcategory. For new sources, the MACT floor cannot be less stringent than the emission control achieved in practice by the best-controlled similar source. For major sources, CAA section 112(d) also requires EPA to consider whether more stringent limits—known as beyond the floor standards—are achievable after taking into consideration the cost of achieving such emission reduction, any non-air health and environmental impacts, and energy impacts.

The Agency acquired unit-specific data and data on mercury from coal-fired units in an ICR approved on November 13, 1998 (OMB Control No. 2060–0396). These data were gathered in advance of the December 20, 2000 regulatory finding. These data sources are now over 10 years old and addressed only coal-fired electric utility steam generating units and only mercury emissions from such units. The Agency is aware that significant changes have been made in the intervening years in the number of operating coal- and oil-fired units, in industry ownership practices, and in emission control configurations. Further, in light of the statutory requirements for establishing emission standards under section 112(d) and the recent case law interpreting those requirements, the Agency believes that it needs additional data from both coal- and oil-fired electric utility steam generating units. We believe that obtaining updated information will be crucial to informing our decision on the NESHAP for coal- and oil-fired electric utility steam generating units.

The information in this ICR will be collected under authority of CAA section 114. CAA section 114(a) states, in pertinent part:

> For the purpose * * * (i) of * * * developing * * * any emission standard under section 7412 of this title * * * or (iii) carrying out any provision of this Chapter * * * (1) the Administrator may require any person who owns or operates any emission source * * * who the Administrator believes may have information necessary for the purposes set forth in this subsection * * * on a one-time, periodic or continuous basis to- * * * (B) make such reports * * *; (E) keep records on control equipment parameters, production variables or other indirect data when direct monitoring of emissions is impractical * * *, and (G) provide such other information as the Administrator may reasonably require * * *

The data collected will be used to confirm the population of potentially affected coal- and oil-fired electric utility steam generating units, and update existing emission test data and fuel analysis information. These data will be used by the Agency to develop the NESHAP for coal- and oil-fired electric utility steam generating units under CAA section 112(d). Specifically, the data will provide the Agency with updated information on the number of potentially affected units, and available emission test data and fuel analysis data to address variability. All data collected will be added to existing emission test databases for coal- and oil-fired electric utility steam generating units; it will also be used to further evaluate the HAP emissions from these sources.

This collection of information is mandatory under CAA section 114 (42 U.S.C. 7414). All information submitted to EPA pursuant to this ICR for which a claim of confidentiality is made is safeguarded according to Agency policies in 40 CFR part 2, subpart B. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9.

The EPA would like to solicit comments to:

(i) Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the Agency, including whether the information will have practical utility;

(ii) Evaluate the accuracy of the Agency's estimate of the burden of the proposed collection of information, including the methodology and assumptions used;

(iii) Enhance the quality, utility, and clarity of the information to be collected; and

(iv) Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated electronic, mechanical, or other technological collection techniques or other forms of information technology (*e.g.*, permitting electronic submission of responses).

Burden Statement: The projected cost and hour burden for this one-time collection of information is $104,807,458 and 100,370 hours. This burden is based on an estimated 555 facilities (1,325 units) being respondents to the survey and required emission testing. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements which have subsequently changed; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

The ICR provides a detailed explanation of the Agency's estimate, which is only briefly summarized here.

Estimated total number of potential respondents: 555 facilities (1,325 units).

Frequency of response: One time.

Estimated total average number of responses for each respondent: 1.

Estimated total annual burden hours: 100,370.

Estimated total annual burden costs: $104,807,458.

What Is the Next Step in the Process for This ICR?

EPA will consider the comments received and amend the ICR as appropriate. The final ICR package will then be submitted to OMB for review and approval pursuant to 5 CFR 1320.12. At that time, EPA will issue another Federal Register notice pursuant to 5 CFR 1320.5(a)(1)(iv) to announce the submission of the ICR to OMB and the opportunity to submit additional comments to OMB. If you have any questions about this ICR or the approval process, please contact the technical person listed under FOR FURTHER INFORMATION CONTACT.

Dated: June 26, 2009.

Mary E. Henigin,

Acting Director, Sector Policies and Programs Division.

[FR Doc. E9–15686 Filed 7–1–09; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OECA–2008–0369; FRL–8925–4]

Agency Information Collection Activities; Submission to OMB for Review and Approval; Comment Request; NESHAP for Clay Ceramics Manufacturing (Renewal), EPA ICR Number 2023.04, OMB Control Number 2060–0513

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*), this document announces that an Information Collection Request (ICR) has been forwarded to the Office of Management and Budget (OMB) for review and approval. This is a request to renew an existing approved collection. The ICR, which is abstracted below, describes the nature of the collection and the estimated burden and cost.

DATES: Additional comments may be submitted on or before August 3, 2009.

ADDRESSES: Submit your comments, referencing docket ID number EPA–OECA–2008–0369, to (1) EPA online using *http://www.regulations.gov* (our preferred method), or by e-mail to *docket.oeca@epa.gov*, or by mail to: EPA Docket Center (EPA/DC), Environmental Protection Agency, Enforcement and Compliance Docket and Information Center, mail code 28221T, 1200 Pennsylvania Avenue, NW., Washington, DC 20460, and (2) OMB at: Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), Attention: Desk Officer for EPA, 725 17th Street, NW., Washington, DC 20503.

FOR FURTHER INFORMATION CONTACT: Sounjay Gairola, Office of Enforcement and Compliance Assurance, Mail Code 2242A, Environmental Protection Agency, 1200 Pennsylvania Avenue, NW., Washington, DC 20460; telephone number: (202) 564–4003; e-mail address: *gairola.sounjay@epa.gov*.

SUPPLEMENTARY INFORMATION: EPA has submitted the following ICR to OMB for review and approval according to the procedures prescribed in 5 CFR 1320.12. On May 30, 2008 (73 FR 31088), EPA sought comments on this ICR pursuant to 5 CFR 1320.8(d). EPA received no comments. Any additional comments on this ICR should be submitted to EPA and OMB within 30 days of this notice.

EPA has established a public docket for this ICR under docket ID number EPA–HQ–OECA–2008–0369, which is available for public viewing online at *http://www.regulations.gov*, in person viewing at the Enforcement and Compliance Docket in the EPA Docket Center (EPA/DC), EPA West, Room 3334, 1301 Constitution Avenue, NW., Washington, DC. The EPA Docket Center Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Reading Room is (202) 566–1744, and the telephone number for the Enforcement and Compliance Docket is (202) 566–1752.

Use EPA's electronic docket and comment system at *http://www.regulations.gov*, to submit or view public comments, access the index listing of the contents of the docket, and to access those documents in the docket that are available electronically. Once in the system, select "docket search," then key in the docket ID number identified above. Please note that EPA's policy is that public comments, whether submitted electronically or in paper, will be made available for public viewing at *http://www.regulations.gov*, as EPA receives them and without change, unless the comment contains copyrighted material, Confidential Business Information (CBI), or other information whose public disclosure is restricted by statute. For further information about the electronic docket, go to *http://www.regulations.gov*.

Title: NESHAP for Clay Ceramics Manufacturing (Renewal).

ICR Numbers: EPA ICR Number 2023.04, OMB Control Number 2060–0513.

ICR Status: This ICR is scheduled to expire on August 31, 2009. Under OMB regulations, the Agency may continue to conduct or sponsor the collection of information while this submission is pending at OMB. An Agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in title 40 of the CFR, after appearing in the Federal Register when approved, are listed in 40 CFR part 9, and displayed either by publication in the Federal Register or by other appropriate means, such as on the related collection instrument or form, if applicable. The display of OMB control numbers in certain EPA regulations is consolidated in 40 CFR part 9.

Abstract: The National Emission Standards for Hazardous Air Pollutants (NESHAP) for Clay Ceramics Manufacturing (40 CFR part 63, subpart KKKKK) were proposed on July 22, 2002 (67 FR 47893) and promulgated on May 16, 2003 (67 FR 26738).

The affected entities are subject to the General Provisions of the NESHAP at 40 CFR part 63, subpart A, and any changes, or additions to the General Provisions specified at 40 CFR part 63, subpart KKKKK.

Owners or operators of the affected facilities must submit a one-time-only report of any physical or operational changes, initial performance tests, and periodic reports and results. Owners or operators are also required to maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility, or any period during which the monitoring system is inoperative. Reports, at a minimum, are required semiannually.

Burden Statement: The annual public reporting and recordkeeping burden for this collection of information is estimated to average 17 hours per response. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements which have subsequently changed; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

Respondents/Affected Entities: Clay ceramics manufacturing facilities.

Estimated Number of Respondents: 10.

Frequency of Response: Initially, occasionally, and semiannually.

Estimated Total Annual Hour Burden: 527.

Estimated Total Annual Cost: $45,702, which includes labor costs of $42,532, O&M costs of $2,468, and annualized capital/startup costs of $702.

Changes in the Estimates: There is no change in the total estimated burden

INFORMATION COLLECTION REQUEST FOR NATIONAL EMMISION STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAP) FOR COAL- AND OIL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS

Part B of the Supporting Statement

1. Respondent Universe

In 2005, the number of coal- and oil-fired electric utility steam generating facilities owned and operated by publicly-owned utility companies, Federal power agencies, rural electric cooperatives, and investor-owned utility generating companies included approximately 1,325 units (boilers) that generated greater than 25 megawatts-electric (MWe), according to the U.S. Department of Energy/Energy Information Administration (DOE/EIA) Form EIA-767 database. Currently, this database contains the most recent data available from DOE for coal- and oil-fired electric utility steam generating units but DOE/EIA states that (as of the writing of this supporting statement) that the 2007 database is soon to be made publically available. The 2006 EIA-860 database covers some of the same units covered by EIA-767; however, this database also includes units owned and operated by non-utilities (including independent power producers and combined heat and power producers). EPA will query this database to determine if it includes any coal- or oil-fired electric utility steam generating units that meet the Act's definition. Additionally, EPA/OAR/Office of Air Quality Planning and Standards will coordinate with EPA/OAR/Clean Air Markets Division (to obtain an industry configuration database output from their electric utility sulfur dioxide (SO_2) cap-and trade program) for help with the development of the final list of electric utilities in this survey data collection effort. As facilities respond to the ICR data request, the Agency will modify this base list of units to represent all affected sources under this effort.

2. Selection of Units to Conduct Stack Testing

Coal-fired units to be tested will be selected to cover four potential groupings of hazardous air pollutants (HAP) that may be addressed through the use of surrogates based on current understanding of appropriate surrogates. These potential groupings of HAP are acid-gas HAP (e.g., hydrogen chloride (HCl), hydrogen fluoride (HF)), dioxin/furan organic HAP, non-dioxin/furan organic HAP, and mercury and other non-mercury metallic HAP. For oil-fired units, the bases for any surrogacy argument(s) are less well developed and will require more extensive testing. Rationale for the selection of units for each possible surrogate grouping is

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 14
COMPANY Florida Power & Light Company (Direct)
WITNESS R. R. Labauve (RRL-9) (Previously RRL-5)
DATE 11/02/09

discussed below. In the following stack testing, each facility is required to test after the last control device or at the stack if the last control device is not shared with one or more other units. In this way, the facility would test before any "dilution" by gases from a separately-controlled unit.

Coal-fired units, acid gas HAP

The acid-gas HAP, HCl and HF, are water-soluble compounds and are more soluble in water than is SO_2. (Hydrogen cyanide, HCN, representing the "cyanide compounds," is also water-soluble and will be considered an "acid-gas HAP" in this document.) HCl also has a large acid dissociation constant (i.e., HCl is a strong acid) and is, thus, will react easily in an acid-base reaction with (i.e., be readily adsorbed on) caustic sorbents (e.g., lime, limestone). This indicates that both HCl and HF will be more rapidly and readily removed from a flue gas stream than will SO_2, even when only plain water is utilized. In the slurry streams, composed of water and sorbent (e.g., lime, limestone) utilized in both wet and dry flue gas desulfurization (FGD) systems, acid gases and SO_2 are absorbed by the slurry mixture and react to (usually) form solid salts. In fluidized bed combustion (FBC) systems, the acid gases and SO_2 are adsorbed by the sorbent (usually limestone) that is added to the coal and an inert material (e.g., sand, silica, alumina, or ash) as part of the FBC process. The adsorption process is temperature dependent and the cooler the flue gas, the more effectively the acid gases will react with the sorbents. One mole of calcium hydroxide ($Ca(OH)_2$) will neutralize one mole of SO_2, whereas one mole of $Ca(OH)_2$ will neutralize two moles of HCl. A similar reaction occurs with the neutralization of HF. These reactions demonstrate that when using a spray dryer, the HCl and HF are removed more readily than is the SO_2. Given that even more water is available in a wet-FGD system, the same condition would also hold in that situation (i.e., in a wet-FGD, HCl and HF would be removed more readily than SO_2). Thus, emissions of SO_2, a commonly measured pollutant, could be used as a surrogate for emissions of the acid-gas HAP HCl and HF. Although this approach has not been used in any section 112 rules by the Agency, it has been used in a number of State permitting actions (e.g., Arkansas/Plum Point; Kentucky/Spurlock 3; Nebraska/Nebraska City 2; Wisconsin/Elm Road-Oak Creek and Weston 4).

However, potential issues have been raised as to whether SO_2 can serve as a legally defensible surrogate for HCl and HF because the subject HAP (i.e., HCl, HF) must be "inherently present" in the potential surrogate (i.e., SO_2), a condition presented by the Court in

Sierra Club v. EPA, January 13, 2004 ("Copper Smelters") and a condition that is not present with this HAP/surrogate group. In addition, there are coal-fired utility boilers that utilize low chlorine content coals and that do not have FGD systems installed. In order to assess whether any of these units could be among the top performing 12 percent of sources on an HCl-emissions basis, it is necessary to identify and test such units.

Based on data obtained through the 1999 ICR, EPA was able to rank-order the coals used by chlorine content. Although there is variation in the coal chlorine content over a year, this methodology, and the number of units selected, will provide a reasonable basis for ensuring that some low-chlorine coal is included in the testing. From this ranking, EPA selected 360 units at 139 facilities with the lowest chlorine content coals. EPA also evaluated coal-fired units with FGD systems installed. Using a tested SO_2 removal efficiency (at the unit's annual operational factor) of 90 percent or greater as a metric and assuming equal or greater HCl/HF/HCN removal, EPA selected 123 units at 78 facilities with the lowest resulting estimated chlorine emissions. Each of the facilities identified as using a low-chlorine coal would be required to test one unit, assuming its use of the common, low-chlorine content coal and not being equipped with any SO_2 controls. Each facility identified with FGD systems installed would be required to test after that specific FGD control (or at the stack if the FGD control device is not shared with one or more other units). If a facility has more than one unit on the FGD control list, the facility would be required to test only one of those FGD controls (or at the stack if the FGD control device is not shared with one or more other units). The facility units identified in the non-FGD portion of Attachment 4 (i.e., low chlorine coal users) would be required to test for HCl, HF, HCN, SO_2, O_2, carbon dioxide (CO_2), and moisture from the stack gases, and chlorine, fluorine, and sulfur content, higher heating value (HHV), and proximate/ultimate analyses of coal being utilized during the test. Similarly, each of the facilities identified as using an FGD system in Attachment 4 would be required to test one unit, assuming use of an FGD system, for HCl, HF, HCN, SO_2, O_2, CO_2, and moisture from the stack gases, and chlorine, fluorine, and sulfur content, HHV, and proximate/ultimate analyses of coal being utilized during the test.

This would yield an additional 217 data sets to be added to the data set from which to determine the top performing 12 percent.

Coal-fired units, dioxin/furan organic HAP

Dioxin data were obtained in support of the 1998 Utility Report to Congress. However, approximately one-half of those data were listed as being below the minimum detection limit for the given test, indicating potential issues with developing an emission limit. Dioxin/furan emissions from coal-fired utility units are generally considered to be low, presumably because of the insufficient amounts of available chlorine. As a result of previous work conducted on municipal waste combustors (MWC), it has also been proposed that the formation of dioxins and furans in exhaust gases is inhibited by the presence of sulfur.[1] Further, it has been suggested that if the sulfur-to-chlorine ratio (S:Cl) is greater than 1.0, then formation of dioxins/furans is inhibited.[2,3] The vast majority of the coal analyses provided through the 1999 ICR indicated S:Cl values greater than 1.0. Based on data obtained through the 1999 ICR, EPA was able to rank-order the coals used by S:Cl value. Again, although there is variation in the S:Cl value over a year, this methodology, and the number of units selected, will provide a reasonable basis for ensuring that some coals with the S:Cl value sought are included in the testing. From this ranking, EPA selected 394 units at 137 facilities (Attachment 5) with S:Cl values less than 5.0 (a value selected to obtain a sufficient number of units in the pool selected for testing). Each of these facilities would be required to test one unit, assuming use of coal with a common S:Cl value, for dioxins/furans, O_2, CO_2, and moisture from the stack gases, and chlorine and sulfur content, HHV, and proximate/ultimate analyses of the coal being utilized during the test.

In addition, as a result of previous work done on MWC units, EPA identified activated carbon as a potential control technology for dioxin/furan control. Therefore, EPA identified 21 units at 12 facilities with activated carbon injection (ACI) systems installed (Attachment 5). Each of these facilities would be required to test one unit, assuming use of ACI and common coal, for dioxins/furans from the stack gases, and chlorine and sulfur content, HHV, and proximate/ultimate analyses of the coal being utilized during the test.

This would yield an additional 149 data sets to be added to the data set from which to determine the top performing 12 percent.

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[1] Gullett, B.K., et al. Effect of Cofiring Coal on Formation of Polychlorinated Dibenzo-*p*-Dioxins and Dibenzofurans during Waste Combustion. *Environmental Science and Technology*. Vol. 34, No. 2:282-290. 2000.
[2] Raghunathan, K., and B.K. Gullett. Role of Sulfur in Reducing PCDD and PCDF Formation. *Environmental Science and Technology*. Vol. 30, No. 6:1827-1834. 1996.
[3] Li., H., et al. Chlorinated Organic Compounds Evolved During the combustion of Blends of Refuse-derived Fuels and Coals. *Journal of Thermal Analysis*. Vol. 49:1417-1422. 1997.

Coal-fired units, non-dioxin/furan organic HAP

Emissions of carbon monoxide (CO), volatile organic compounds (VOC), and/or total hydrocarbons (THC) have been used as surrogates for the non-dioxin/furan organic HAP based on the theory that efficient combustion leads to lower organic emissions.[4] However, there are very few emissions data available for these compounds from coal-fired utility boilers. Further, the HAP/CO surrogacy pairing has the same issue with the Copper Smelter ruling noted earlier for acid gas HAP/SO_2. Therefore, EPA selected those 274 coal-fired units at 184 facilities (Attachment 6) having come on-line since 1980 as being representative of the most modern, and, thus, presumed most efficient, units. Each facility with one of these units would be required to test one unit, assuming the unit came on-line since 1980, for CO, VOC, THC, polycyclic organic matter (POM), NO_x, formaldehyde, methane, O_2, CO_2, and moisture from the stack gases and HHV and proximate/ultimate analyses of the coal being utilized during the test. This would yield an additional 184 data sets to be added to the data set from which to determine the top performing 12 percent.

Coal-fired units, mercury and other non-mercury metallic HAP

Emissions of certain non-mercury metallic HAP (i.e., antimony (Sb), beryllium (Be), cadmium (Cd), cobalt (Co), lead (Pb), manganese (Mn), and nickel (Ni)) have been assumed to be well controlled by particulate matter (PM) control devices. However, mercury (Hg) and other non-mercury metallic HAP (i.e., arsenic (As), chromium (Cr), and selenium (Se)), because of their presence in both particulate and vapor phases, have been reported, in some instances, to be not well controlled by PM control devices. Also, it has been shown through recent stack testing that certain non-mercury metallic HAP (i.e., As, Cr, and Se) tend to condense on (or as) very fine particulate matter in the emissions from coal-fired units. There are very few recent emissions test data available showing the potential control of these metallic HAP from coal-fired utility boilers. (Phosphorus (P) will be considered a "non-mercury metallic HAP" in this document.)

The capture of Hg is dependent on several factors including the chloride content of the coal, the amount of unburned carbon present in the fly ash, the flue gas temperature, and the speciation of the Hg. Based on available data, EPA believes that ACI may be an effective control technology for controlling Hg emissions in coal-fired plants. However, EPA has no

[4] U.S. Environmental Protection Agency. NESHAPS: Final Standards for Hazardous Air Pollutants for Hazardous Waste Combustors; Final Rule. 64 FR 52828. September 30, 1999.

direct stack test results showing how effectively these ACI-equipped plants reduce their Hg emissions.

Finally, coal contains trace quantities of the naturally-occurring radionuclides (e.g., uranium and thorium), as well as their radioactive decay products, and potassium-40. When coal is burned, minerals, including most of the radionuclides, do not burn and concentrate in the ash. Although most of the ash is captured, fly ash including some radionuclides, escape from the boiler into the atmosphere. There is some indication that the radionuclides partition to, or enrich on, the in the fine particulate fraction of coal-fired emissions. The behavior of uranium and the uranium-decay products has been attributed to the fact that uranium typically occurs in coal in different phases and can, therefore, give rise to both volatile and semi-volatile species during combustion. The only available data on radionuclide emissions from coal-fired EGUs is nearly 15 years old.

For these reasons, EPA selected those 214 coal-fired units at 123 facilities with PM controls having come on-line since 1990 as being representative of the most modern PM controlled units as well as units with ACI in use. Although some of the units meet both criteria, some only meet the ACI usage criteria. The units chosen to meet these two criteria have a good potential for control of fine PM, radionuclides, and Hg. These units are shown in Attachment 7.

Each facility in Attachment 7 would be required to test after that specific PM control (or at the stack if the PM control device is not shared with one or more other units). If a facility has more than one unit on the PM control list, the facility would be required to test after each of those PM controls (or at the stack if the PM control device is not shared with one or more other units). There are several facilities that are listed in both the PM and the ACI portion of this list of units. These facilities can test at the control device exit (or at the stack if the PM control device is not shared with one or more other units) as long as the ACI injection occurs before the PM control listed. Therefore, each of these facilities would be required to test the unit listed, and if ACI equipped, assuming use of ACI and common coal, for Sb, As, Be, Cd, Cr, Cr^{+6}, Co, Pb, Mn, Hg, Ni, Se, P, PM (total filterable, fine [dry], fine [wet]), total solids, black carbon, radionuclides, O_2, CO_2, and moisture. All units would also be required to analyze their coal for the metals above (including Hg), P, radionuclides, chlorine, and provide the HHV and proximate/ultimate analyses of the coal being utilized during the test.

This would yield an additional 214 data sets to be added to the data set from which to determine the top performing 12 percent.

Oil-fired units

The potential surrogacy arguments for coal-fired units are primarily based on the use of add-on control technologies, in the case of the non-mercury metallic HAP (PM) and the acid-gas HAP (HCl, HF), or on the S:Cl value for the dioxin/furan organic HAP. However, the data obtained in support of the 1998 Utility Report to Congress and the 2000 Regulatory Determination do not indicate any correlation between PM control and emissions of non-mercury metallic HAP from oil-fired units. Further, no oil-fired unit has a FGD system installed, eliminating the potential basis for the use of emissions of SO_2 as a surrogate for emissions of the acid-gas HAP from such units. In addition, it is not known if the S:Cl value has the same relevance for oil-fired units as it does for coal-fired units. Thus, EPA has no basis for determining which oil-fired units may be the "best performers." Therefore, all units at each facility that are controlled by a fabric filter or an electrostatic precipitator (77 units at 38 facilities) and 1 unit at each facility where all units are controlled by only multiclones or have no PM control (112 units at 39 facilities) in Attachment 8, would be required to test their stack emissions for Sb, As, Be, Cd, Cr, Cr^{+6}, Co, Pb, Mn, Hg, Ni, Se, P, PM (total filterable, fine [dry], fine [wet]), black carbon, radionuclides, HCl, HF, HCN, SO_2, dioxins/furans, CO, VOC, THC, POM, NO_x, formaldehyde, methane, O_2, CO_2, and moisture. All units would be required to sample their oil for the metals (including Hg), P, radionuclides, chlorine, fluorine, sulfur, and provide HHV and proximate/ultimate analyses of the oil being utilized during the test.

3. Response Rates

Since the information will be requested pursuant to the authority of CAA section 114, EPA expects that all respondents requested to submit information will do so.

Attachment 1.

Draft Questionnaire Content

Form Approved __/__/__
OMB Control No. ____-____
Approval Expires __/__/__

ELECTRIC UTILITY STEAM GENERATING UNIT

HAZARDOUS AIR POLLUTANT EMISSIONS INFORMATION COLLECTION EFFORT

BURDEN STATEMENT

Preliminary estimates of the public burden associated with this information collection effort indicate a total of 100,370 hours and $104,807,458. This is the estimated burden for 555 facilities to provide information on their boilers, fuel oil types and/or coal rank, 1,325 units to provide hazardous air pollutant (HAP) emission data and 12 months of fuel analyses, and 880 units to conduct emissions testing.

Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal Agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information. An Agency may not conduct or sponsor, and a person is not required to respond to, a collection of information that is sent to ten or more persons unless it displays a currently valid Office of Management and Budget (OMB) control number.

GENERAL INSTRUCTIONS

[NOTE: It is EPA's intent for the final version of this questionnaire to be in electronic format. The final format will include all questions noted herein.]

Please provide the information requested in the following forms. If you are unable to respond to an item as it is stated, please provide any information you believe may be related. Use additional copies of the request forms for your response.

If you believe the disclosure of the information requested would compromise confidential business information (CBI) or a trade secret, clearly identify such information as discussed in the cover letter. Any information subsequently determined to constitute CBI or a trade secret under EPA's CBI regulations at 40 CFR part 2, subpart B, will be protected pursuant to those regulations and, for trade secrets, under 18 U.S.C. 1905. If no claim of confidentiality accompanies the information when it is received by EPA, it may be made available to the public by EPA without further notice pursuant to EPA regulations at 40 CFR 2.203. Because Clean Air Act (CAA) section 114(c) exempts emission data from claims of confidentiality, the emission data you provide may be made available to the public notwithstanding any claims of confidentiality. A definition of what the EPA considers emissions data is provided in 40 CFR 2.301(a)(2)(i).

The following section is to be completed by all facilities:

- Part I - General Facility Information: once for each facility. A copy of Part I should be completed and returned to the address noted below within 60 days of receipt.

The following section is to be completed by all facilities meeting the section 112(a)(8) definition of an electric utility steam generating unit:

- Part II - Fuel Analyses and Emission Data: Additional copies of certain pages may be necessary for a complete response. A copy of Part II responses should be completed and returned to the address noted below within 60 days of receipt.

The following section is to be completed by all facilities selected for stack testing:

- Part III – Emissions Test Data: One emissions test (consisting of three runs). A copy of the emissions test report should be completed and returned to the address noted below within 6 months of receipt.

Detailed instructions for each part follow.

Questions regarding this information request should be directed to Mr. Bill Maxwell at (919) 541-5430.

Return this information request and any additional information to:

Sector Policies and Programs Division (Mail Code D205-01)
U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

Attention: Peter Tsirigotis, Director

Form Approved __/__/__
OMB Control No. ____-____
Approval Expires __/__/__

12. For each boiler noted in Part I, question 15, provide the following information:

Boiler ID	Emissions test results (indicate format of emission data)[36]							
	Date of test	PM[37]	SO_2	HCl/HF/HCN	Metal HAP[38]	Hg[39]	CO	Other organics (specify)

[36] Provide emission test data for all tests conducted since January 1, 2004. Please include test data acquired both before and after any control device. Use additional pages as necessary. EPA may, at some future date, request a copy of one or more emission test reports. Data generated to fulfill both Federal and State requirements must be provided. Note that data generated pursuant to CAA Title V must be maintained and available for 5 years.

[37] If emission testing recorded the emissions of filterable and condensable PM, separately, please include those separate emission results. Also, please include separate emission results for total PM, PM_{10}, and $PM_{2.5}$.

[38] Metal HAP include compounds of antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, phosphorus radionuclides, and selenium; indicate emission level for all metal HAP for which an emission test has been conducted.

[39] Please provide separate results for total Hg, elemental Hg, oxidized Hg, and particulate Hg, as available. If the emissions testing recorded the amount of unburned carbon in fly ash (as reflected by the "Loss of Ignition" [L.O.I.]) at the time of any Hg testing, please include these data.

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OMB Control No. ____-____
Approval Expires __/__/__

PART III: EMISSION TESTING

For units identified in Part B of the Supporting Statement, testing is to be performed for the identified HAP on a one-time basis after the last control device (i.e., after the last control device or at the stack if the last control device is not shared with one or more other units). Facilities are to use the test procedures noted in Enclosure 1 ("Summary of Coal- and Oil-fired Electric Utility Steam Generating Unit Test Procedures, Methods, and Reporting Requirements") for both the stack and fuel sampling. Each test is to consist of three separate runs at the sampling location. EPA requires that the facility conduct paired trains for the fine particulate matter testing (which is included in the testing of units for mercury and other non-mercury metallic HAP) and duplicate trains for the other HAP being tested. Emission measurements frequently consist of a sequential set (typically three) of singular method tests over the course of several hours or days. In contrast, a sequential set of duplicate or paired method tests provides the only measure of test method precision, thereby facilitating identification of test data "outliers" occasionally generated through improper test method execution, versus true source emission variability. Indeed, paired method data provides a quantifiable way to identify and distinguish between erratic test data and actual emission variations. EPA is considering requiring testing twice within the test period to account for variability in emissions testing.

Enclosure 1

Summary of Coal- and Oil-fired Electric Utility Steam Generating Unit Test Procedures, Methods, and Reporting Requirements

This document provides an overview of approved methods, target pollutant units of measure, and reporting requirements for the coal- and oil-fired electric utility steam generating unit test plan. The document is organized as follows:

1.0 Stack Testing Procedures and Methods
2.0 Fuel Analysis Procedures and Methods
3.0 How to Report Data
4.0 How to Submit Data
5.0 Definitions
6.0 Contact Information for Questions on Test Plan and Reporting

1.0 Stack Testing Procedures and Methods

The EPA coal- and oil-fired electric utility steam generating unit test program includes stack test data requests for several pollutants, including specific hazardous air pollutants (HAP) and potential surrogate groups. If you operate a coal- or oil-fired electric utility steam generating unit, you were selected to perform a stack test for some combination of the following pollutants or potential surrogate groups:

- Non-dioxin/furan organic HAP: Carbon monoxide (CO), total hydrocarbons (THC), volatile organic compounds (VOC); polycyclic organic matter (POM), methane, formaldehyde, oxygen (O_2), carbon dioxide (CO_2), oxides of nitrogen (NO_X), volatile and semi-volatile organic HAP
- Dioxin/furan: dioxins/furans (D/F), O_2, CO_2
- Acid gas HAP: hydrogen chloride (HCl), hydrogen fluoride (HF), hydrogen cyanide (HCN), sulfur dioxide (SO_2), O_2, CO_2
- Mercury and non-mercury metallic HAP: mercury (Hg), HAP metals (including antimony (Sb), arsenic (As), beryllium (Be), cadmium (Cd), chromium (Cr), Cr^{+6}, cobalt (Co), lead (Pb), manganese (Mn), nickel (Ni), phosphorus (P) and selenium (Se)), radionuclides, particulate matter (PM – total filterable, $PM_{2.5}$ (wet and dry), and condensable); total solids; carbon (black, elemental, organic), O_2, CO_2

Refer to Table _ on page _ of the section 114 letter you received for the specific combustion unit and pollutants we are requesting that you perform emission tests. You may have submitted test data for some of these pollutants already.

1.1 How to Select Sample Location and Gas Composition Analysis Methods

U.S. EPA Method 1 of Appendix A of Part 60 must be used to select the locations and number of traverse points for sampling. See http://www.epa.gov/ttn/emc/methods/method1.html for a copy of the method and guidance information.

Enclosure 1

Analysis of flue gas composition, including oxygen concentration, must be performed using U.S. EPA Methods 3A or 3B of Appendix A of Part 60. See http://www.epa.gov/ttn/emc/methods/method3a.html for Method 3A or http://www.epa.gov/ttn/emc/methods/method3b.html for Method 3B information.

1.2 Coal- and Oil-fired Electric Utility Steam Generating Unit Test Methods and Reporting

Table 1.2 presents a summary of the recommended test methods for each pollutant and possible alternative methods. If you would like to use a method not on this list, and the list does not meet the definition of "equivalent" provided in the definitions section of this document, please contact EPA for approval of an alternative method.

For copies of the recommended U.S. EPA methods and additional information, please refer to EPA's Emission Measurement Center website: http://www.epa.gov/ttn/emc/. A copy of RCRA Method 0011 for aldehydes may be obtained here: http://www.epa.gov/epawaste/hazard/testmethods/sw846/pdfs/0011.pdf.

Report pollutant emission data as specified in Table 1.2 below. Each test should be comprised of three test runs. All pollutant concentrations should be corrected to 7 percent oxygen and should be reported on the same moisture basis. Report the results of the stack tests according to the instructions in Section 3.0 of this enclosure. In addition to the emission test data, you should also report the following process information taken during the 30 day period before, at the time of, and during, the emissions test: Heat input; fuel composition and feed rate; steam output; emissions control devices in use during the test; control device operating or monitoring parameters (including, as appropriate to the control device, flue gas flow rate, pressure drop, scrubber liquor pH, scrubber liquor flow rate, sorbent type and sorbent injection rate), and process parameters (such as oxygen).

Table 1.2: Summary of Coal- and Oil-fired Electric Utility Steam Generating Unit Test Methods and Alternative Methods

Pollutant	Recommended Method	Alternative Method	Target Reported Units of Measure
CO	U.S. EPA Method 10, 10A, or 10B	None	ppmvd @ 7% O_2
Formaldehyde	U.S. EPA Method 320 with a minimum sample time of 1 hour per run.	RCRA Method 0011. Collect a minimum volume of 2.5 cubic meters or have a minimum sample time of 2 hours per run.	ppmvd @ 7% O_2
HCl and HF	U.S. EPA Method 26A	U.S. EPA Method 26 if there are no entrained water droplets in the sample or U.S. EPA Method 320.	lb/MMBtu

Enclosure 1

Pollutant	Recommended Method	Alternative Method	Target Reported Units of Measure
HCN	U.S. EPA Conditional Test Method 033 (CTM-033)	U.S. EPA Method 26A combined with the analysis procedures from CTM-033, U.S. EPA Method 320, or U.S. EPA Method 26 combined with the analysis procedures from CTM-033, U.S. EPA Method 320 if there are no entrained water droplets in the sample.	lb/MMBtu
Hg	ASTM-D6784-02 (Ontario Hydro Method). Collect a minimum volume of 2.5 cubic meters or have a minimum sample time of 2 hours per run.	U.S. EPA Method 29* or U.S. EPA Method 30B.	lb/MMBtu
Cr^{+6}	U.S. EPA SW-846 Method 0061	U.S. EPA Method 29*. Report all Cr as Cr^{+6}.	lb/MMBtu
Metals	U.S. EPA Method 29** No permanganate solution needed, if Hg will not be measured. Collect a minimum volume of 4.0 cubic meters or have a minimum sample time of 4 hours per run. Determine total filterable PM emissions according to §8.3.1.1. Use IC(A)P/MS for the analytical finish. Report all metals results, and report all Cr as Cr^{+6}.	None	lb/MMBtu
Radionuclides	U.S. EPA Method 114. Conduct on digestate of front half filter and on back half of Method 29	None	Microcuries/dry standard cubic meter
$PM_{2.5}$ from stacks without entrained water droplets (e.g., not from units with wet scrubbers)	U.S. EPA Other Test Method 27 (OTM 27) (include cyclone catch***)	None	lb/MMBtu
Black Carbon (BC), elemental carbon (EC), and organic carbon (OC)	Analysis by Magee Scientific Model OT21 – take sample from M201A or M5 filter post gravimetric determination AND IMPROVE_A Thermal/Optical Carbon Analysis		lb/MMBtu for BC, EC, and OC

Enclosure 1

Pollutant	Recommended Method	Alternative Method	Target Reported Units of Measure
$PM_{2.5}$ from stacks with entrained water droplets AND Total Dissolved Solids (TDS) and Total Suspended Solids (TSS) from wet scrubber recirculation liquid	U.S. EPA Method 5 with a filter temperature of 320°F +/- 25°F AND ASTM D5907	For TDS and TSS, Standard Methods of the Examination of Water and Wastewater Method 2540B for solids in scrubber recirculation liquid	lb/MMBtu for PM; AND mg solids liter of scrubber recirculation liquid****
PM (condensable)	U.S. EPA Other Test Method 28 (OTM 28)	None	lb/MMBtu
THC	U.S. EPA Method 25A with a minimum sampling time of one hour per run. Calibrate the measuring instrument with a mixture of the organic compounds being emitted or with propane.	None	ppmvd @ 7% O2
CH_4	U.S. EPA Method 18. Have a minimum sample time of 1 hour per run.	U.S. EPA Method 320.	ppmvd @ 7% O2
D/F, PCB*****	U.S. EPA Method 23. Collect a minimum volume of 10 cubic meters or have a minimum sample time of 8 hours per run. Use high resolution GCMS for the analytical finish.	None	ng/dscm @ 7% O2
Speciated Volatile Organic HAP	U.S. EPA Method 0031with SW-846 Method 8260B. Collect a minimum volume of 10 cubic meters or have a minimum sample time of 8 hours per run.	None	µg/dscm @ 7% O2
Speciated Semi-volatile Organic HAP	U.S. EPA Method 0010 with SW-846 Method 8270D. Collect a minimum volume of 10 cubic meters or have a minimum sample time of 8 hours per run. Use high resolution GCMS for the analytical finish.	None	µg/dscm @ 7% O2
NO_x******	U.S. EPA Method 7E	U.S. EPA Method 7, 7A, 7B, 7C, or 7D	ppmvd @ 7% O_2
SO_2******	U.S. EPA Method 6C	U.S. EPA Method 6	ppmvd @ 7% O_2
O_2/CO_2	U.S. EPA Method 3A	U.S. EPA Method 3B	%
Moisture	U.S. EPA Method 4	None	%

*Method 29 in appendix A-8 to part 60 of this chapter can also be used for Hg, but follow the procedures for preparation of Hg standards and sample analysis in sections 13.4.1.1 through 13.4.1.3 of ASTM D6784-02 instead of the procedures in sections 7.5.33 and 11.1.3 of Method 29, and perform the QA/QC procedures in section 13.4.2 of ASTM D6784-02 instead of the procedures in section 9.2.3 of Method 29. The tester may also opt to use the sample recovery and preparation procedures in ASTM D6784-02 instead of the Method 29 procedures, as follows:

Enclosure 1

sections 8.2.8 and 8.2.9.1 of Method 29 can be replaced with sections 13.2.9.1 through 13.2.9.3 of ASTM D6784-02; sections 8.2.9.2 and 8.2.9.3 of Method 29 can be replaced with sections 13.2.10.1 through 13.2.10.4 of ASTM D6784-02; section 8.3.4 of Method 29 can be replaced with section 13.3.4 or 13.3.6 of ASTM D6784-02 (as appropriate); and section 8.3.5 of Method 29 can be replaced with section 13.3.5 or 13.3.6 of ASTM D6784-02 (as appropriate).

If both mercury and other metals will be testing using EPA Method 29, the stack test company should be diligent in the set-up and handling of the impingers to avoid cross contamination of the manganese from the permanganate into the metals catch. Alternately, the contractor may want to collect mercury on a separate train from the train used to collect the other metals.

**If both mercury and other metals will be testing using EPA Method 29, the stack test company should be diligent in the set-up and handling of the impingers to avoid cross contamination of the manganese from the permanganate into the metals catch. Alternately, the contractor may want to collect mercury on a separate train from the train used to collect the other metals.

***PM filterable is determined by including the cyclone catch.

****Also report scrubber recirculation liquid flow rate in liters/min and fuel feed rate in MMBTU/hr.

*****Just the 12 "dioxin-like" PCB congeners (see the WHO PCB Congener List)

******If a combustion unit has CEMS installed for CO, NO_x and/or SO_2, the unit can report daily averages from 30 days of CEMS data in lieu of conducting a CO, NO_x and/or SO_2 stack test. In order to correlate these emissions with other stack test emissions, a portion of the CEMS data should contain emissions data collected during performance of the other requested stack tests. The CEMS must meet the requirements of the applicable Performance Specification: CO – Performance Specification 4; NO_x and SO_2 – Performance Specification 2.

2.0 Fuel Analysis Procedures and Methods

The EPA coal- and oil-fired electric utility steam generating unit test program is requesting fuel variability data for fuel-based HAP. The fuel analyses requested include: mercury, chlorine, fluorine, and metals (antimony, arsenic, beryllium, cadmium, chromium, cobalt, lead, manganese, nickel, phosphorus, and selenium) for any coal- and oil-fired electric utility steam generating unit that is selected to conduct a stack test.

You will need to conduct one fuel sample (comprised of three composite samples, each individually analyzed) of the fuel used during the stack test (one composite sample per test run).

Refer to page 1 of the Section 114 letter you received for the specific types of fuel analyses we are requesting from your facility. Directions for collecting, compositing, preparing, and analyzing fuel analysis data are outlined in Sections 2.1 through 2.4.

2.1 How to Collect a Fuel Sample

Table 2.1 outlines a summary of how samples should be collected. Alternately, you may use the procedures in ASTM D2234–00 (for coal) to collect the sample.

Table 2.1: Summary of Sample Collection Procedures

Sampling Location	Sampling Procedures	Sample Collection Timing
	Solid Fuels	
Belt or Screw Feeder	Stop the belt and withdraw a 6- inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. Collect all the material (fines and coarse) in the full cross-section. Transfer the sample to a clean plastic bag for further processing as specified in Sections 2.2 through 2.5 of this document.	Each composite sample will consist of a minimum of three samples collected at approximately equal intervals during the testing period.
Fuel Pile or Truck	For each composite sample, select a minimum of five sampling locations uniformly spaced over the surface of the pile. At each sampling site, dig into the pile to a depth of 18 inches. Insert a clean flat square shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling. Transfer all samples to a clean plastic bag for further processing as specified in Sections 2.2 through 2.5 of this document.	
	Liquid Fuels	
Manual Sampling	Follow collection methods outlined in ASTM D 4057	
Automatic Sampling	Follow collection methods outlined in ASTM D4177	

Sampling Location	Sampling Procedures	Sample Collection Timing
	Fuel Supplier Analysis	
Fuel Supplier	If you will be using fuel analysis from a fuel supplier in lieu of site specific sampling and analysis, the fuel supplier must collect the sample as specified above and prepare the sample according to methods specified in Sections 2.2 through 2.5 of this document.	

2.2 Create a Composite Sample for Solid Fuels

Follow the seven steps listed below to composite each sample:

(1) Thoroughly mix and pour the entire composite sample over a clean plastic sheet.
(2) Break sample pieces larger than 3 inches into smaller sizes.
(3) Make a pie shape with the entire composite sample and subdivide it into four equal parts.
(4) Separate one of the quarter samples as the first subset.
(5) If this subset is too large for grinding, repeat step 3 with the quarter sample and obtain a one-quarter subset from this sample.
(6) Grind the sample in a mill according to ASTM E829-94, or for selenium sampling according to SW-846-7740.
(7) Use the procedure in step 3 of this section to obtain a one quarter subsample for analysis. If the quarter sample is too large, subdivide it further using step 3.

2.3 Prepare Sample for Analysis

Use the methods listed in Table 2.2 to prepare your composite samples for analysis.

Table 2.2: Methods for Preparing Composite Samples

Fuel Type	Method
Solid	SW-846-3050B or EPA 3050 for total selected metal preparation
Liquid	SW-846-3020A or any SW-846 sample digestion procedures giving measures of total metal
Coal	ASTM D2013-04
Biomass	ASTM D5198-92 (2003) or equivalent, EPA 3050, or TAPPI T266 for total selected metal preparation

2.4 Analyzing Fuel Sample

Table 2.3 outlines a list of approved methods for analyzing fuel samplings. If you would like to use a method not on this list, and the list does not meet the definition of "equivalent" provided in Section 5 of this document, please contact EPA for approval of an alternative method.

Table 2.3: List of Analytical Methods for Fuel Analysis

Analyte	Fuel Type	Method	Target Reported Units of Measure
Higher Heating Value	Coal	ASTM D5865–04, ASTM D240, ASTM E711-87 (1996)	
	Biomass	ASTM E711–87 (1996) or equivalent, ASTM D240, or ASTM D5865-04	
	Other Solids	ASTM-5865-03a, ASTM D240, ASTM E711-87 (1997)	
	Liquid	ASTM-5865-03a, ASTM D240, ASTM E711-87 (1996)	Btu/lb
Moisture	Coal, Biomass, Other Solids	ASTM-D3 173-03, ASTM E871-82 (1998) or equivalent, EPA 160.3 Mod., or ASTM D2691-95 for coal.	%
Mercury Concentration	Coal	ASTM D6722-01, EPA Method 1631E, SW-846-1631, EPA 821-R-01-013, or equivalent	
	Biomass	SW-846-7471A, EPA Method 1631E, SW-846-1631, ASTM D6722-01, EPA 821-R-01-013, or equivalent	
	Other Solids	SW-846-7471A, EPA Method 1631E, SW-846-1631, EPA 821-R-01-013, or equivalent	ppm
	Liquid	SW-846-7470A, EPA Method 1631E, SW-846-1631E, SW-846-1631, EPA 821-R-01-013, or equivalent	
Total Selected Metals Concentration	Coal	SW-846-6010B, ASTM D3683-94 (2000), SW-846-6020, -6020A or ASTM D6357-04 (for arsenic, beryllium, cadmium, chromium, lead, manganese, and nickel in coal) ASTM D4606-03 or SW-846-7740 (for Se) SW-846-7060 or 7060A (for As)	ppm
	Biomass	SW-846-6010B, ASTM D6357-04, SW-846-6020, -6020A, EPA 200.8, or ASTM E885-88 (1996) or equivalent, SW-846-7740 (for Se) SW-846-7060 or -7060A (for As)	
	Other Solids	SW-846-6010B, EPA 200.8 SW-846-7060 or 7060A for As	
	Liquid	SW-846-6020, -6020A, , SW-846-6010B, SW-846-7740 for Se, SW-846-7060 or -7060A for As	
Chlorine Concentration	Coal	SW-846-9250 or ASTM D6721-01 or equivalent, SW-846-5050, -9056, -9076, or -9250, ASTM E776-87 (1996)	
	Biomass, Other Solids, Liquids	ASTM E776-87 (1996), SW-846-9250, SW-846-5050, -9056, -9076, or -9250	ppm
Fluorine Concentration	Coal	ASTM D3761-96(2002), D5987-96 (2002)	ppm

Report the results of your fuel analysis according to the directions provided in section 3.0 of this enclosure.

3.0 How to Report Data

The method for reporting the results of any testing and monitoring requests depend on the type of tests and the type of methods used to complete the test requirements. This section discusses the requirements for reporting the data.

3.1 Reporting stack test data

If you conducted a stack test using one of the methods listed in Table 3.1, (Method 6C, Method 7E, Method 10, Method 17, Method 25A, Method 26A, Method 29, Method 101, Method 101A, Method 201A, Method 202) you must report your data using the EPA Electronic Reporting Tool (ERT) Version 3. At present, only these methods are supported by the ERT. ERT is a Microsoft ® Access database application. Two versions of the ERT application are available. If you are not a registered owner of Microsoft ® Access, you can install the runtime version of the ERT Application. Both versions of the ERT are available at http://www.epa.gov/ttn/chief/ert/ert_tool.html. The ERT supports an Excel spreadsheet application (which is included in the files downloaded with the ERT) to document the collection of the field sampling data. After completing the ERT, will also need to attach an electronic copy of the emission test report (PDF format preferred) to the Attachments module of the ERT.

Table 3.1: List of Test Methods Supported by ERT

Test Methods Supported by ERT
Methods 1 through 4
Method 7E
Method 6C
Method 5
Method 3A
Method 29
Method 26A
Method 25A
Method 202
Method 201A
Method 17
Method 101A
Method 101
Method 10
CT Method 40
CT Method 39

If you conducted a stack test using a method not currently supported by the ERT, you must report the results of this test in a Microsoft ® Excel Emission Test Template. The Excel templates are specific to each pollutant and type of unit and they can be downloaded from {*to be added later*}. You must report the results of each test on appropriately labeled worksheet corresponding to the specific tests requested at your combustion unit. If more than one unit at your facility conducted a stack test using methods not currently supported by the ERT, you must make a copy of the worksheet and update the combustor ID in order to distinguish between each separate test. After completing the worksheet, you must also submit an electronic copy of the emission test report (PDF format preferred).

If you have CO CEMS that meets performance specification-4 or a SO_2 and/or NO_x CEMS that meets performance specification-2 installed at your combustion unit, and you used CEMS data to meet CO, SO_2 and/or NO_x test requirements at your facility, you must report daily averages from 30 days of CEMS data in a Microsoft ® Excel CEMS Template. The Excel templates are specific to each pollutant and type of unit and they can be downloaded from {*to be added later*}.

3.2 Reporting Fuel Analysis Data

If you conducted a fuel analysis, you must report the analysis results separately for each of the 12 samples in a Microsoft ® Excel Fuel Analysis Template. The fuel samples collected in conjunction with the stack test are comprised of three composite samples, each of which is analyzed separately. The remaining nine additional fuel samples are also comprised of three composite samples, but only the combined composite samples are analyzed. The Excel template can be downloaded from {*to be added later*}. If you conducted fuel analysis on more than one type of fuel used during testing, or for more than one combustion unit, you must make a copy of the worksheet and update the combustor ID and fuel type in each worksheet order to distinguish between the separate fuel analyses.

3.3 Required Fields for ERT Reporting

This section outlines the required data entry fields for the ERT in order to satisfy the requirements of this ICR test program. Appendix A {*to be provided later*} lists each field within the ERT and notes whether or not the field is required or optional.

4.0 How to Submit Data

You may submit your data in one of three ways as listed below. However, in order to avoid duplicate data and keep all data for a particular facility together, we request that you submit all of the data requested from your facility in the same way. To submit your data:

- E-mail an electronic copy of all requested files to {*to be added later*}
- If the files are too large for your e-mail system, you may upload the electronic files to a FTP site (see directions for FTP site procedures below)
- Mail a CD or DVD containing an electronic copy of all requested files to the EPA address shown in your Section 114 letter. If no electronic copy is available, mail a hard copy of all requested files to the EPA address shown in your Section 114 letter.
- If you are submitting Confidential Business Information (CBI), you must mail a separate CD or DVD containing only the CBI portion of your data to the EPA address shown in your Section 114 letter.

The steps below outline how to upload files to the FTP site by using "My Computer" as well as by using a FTP Client software.

Directions for accessing the FTP site via "My Computer"...

{*To be added later*}

5.0 Definitions

The following definitions apply to the coal- and oil-fired electric utility steam generating unit test plan methods:

Equivalent means:

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.

(2) An equivalent sample compositing procedure means a published VCS or EPA method to systematically mix and obtain a representative subsample (part) of the composite sample.

(3) An equivalent sample preparation procedure means a published VCS or EPA method that: Clearly states that the standard, practice or method is appropriate for the pollutant and the fuel matrix; or is cited as an appropriate sample preparation standard, practice or method for the pollutant in the chosen VCS or EPA determinative or analytical method.

(4) An equivalent procedure for determining heat content means a published VCS or EPA method to obtain gross calorific (or higher heating) value.

(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining metals (especially the mercury, selenium, or arsenic) using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing these metals. On the other hand, if metals analysis is done on an "as received" basis, a separate aliquot can be dried to determine moisture content and the metals concentration mathematically adjusted to a dry basis.

(6) An equivalent pollutant (mercury, TSM, or total chlorine) determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for the pollutant and the fuel matrix and has a published detection limit equal or lower than the methods listed in this test plan.

Voluntary Consensus Standards or VCS mean technical standards (*e.g.*, materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. EPA/OAQPS has by precedent only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM), American Society of Mechanical Engineers (ASME), International Standards Organization (ISO), Standards Australia (AS), British Standards (BS), Canadian Standards (CSA), European Standard (EN or CEN) and German Engineering Standards (VDI). The types of standards that are not considered VCS are standards developed by: the U.S. States, such as California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, such as Department of Defense (DOD) and Department of Transportation (DOT).

This does not preclude EPA from using standards developed by groups that are not VCS bodies within their rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-EPA methods.

6.0 Contact Information for Questions on Test Plan and Reporting

For questions on how to report data using the ERT, contact:
Ron Myers
U.S. EPA
(919) 541-5407
myers.ron@epa.gov

or

Barrett Parker
U.S. EPA
(919) 541-5635
parker.barrett@epa.gov

For questions on the test methods contact:
Peter Westlin
U.S. EPA
(919) 541-1058
westlin.peter@epa.gov

OR

Gary McAlister
U.S. EPA
(919) 541-1062
mcalister.gary@epa.gov

For questions on the coal- and oil-fired electric utility steam generating unit test plan, including units selected to test and reporting mechanisms other than the ERT, contact:
William Maxwell
U.S. EPA
(919) 541-5430
maxwell.bill@epa.gov

For questions on uploading files to the FTP site, contact:
{*To be provided later.*}

Attachment 4.

List of coal-fired electric utility steam generating units selected for HCl/HF/HCN acid gas HAP testing

State	Facility Name	Coal rank	No. units	Scrubber
WI	J. P. Madgett	Subbituminous	1	N
MN	Black Dog Generating Plant	Subbituminous	2	N
KS	Tecumseh	Subbituminous; Bituminous	2	N
MO	Lake Road Plant	Subbituminous	1	N
WI	Columbia	Subbituminous	2	N
OK	Sooner	Subbituminous	2	N
NE	Lon Wright	Subbituminous	1	N
IA	Burlington	Subbituminous	1	N
MO	Thomas Hill	Subbituminous	3	N
OK	Muskogee	Subbituminous	3	N
OK	Northeastern	Subbituminous	2	N
TX	Coleto Creek	Subbituminous; Bituminous	1	N
KS	Nearman Creek	Subbituminous	1	N
MN	Laskin Energy Center	Subbituminous	2	N
NE	Gerald Gentleman Station	Subbituminous	2	N
AR	Flint Creek	Subbituminous	1	N
TX	Welsh	Subbituminous	3	N
MO	Labadie	Subbituminous	4	N
LA	Big Cajun 2	Subbituminous	3	N
MN	Clay Boswell Energy Center	Subbituminous	4	N
SD	Big Stone	Subbituminous	1	N
IA	Prairie Creek	Subbituminous	2	N
MO	Sibley	Subbituminous; Bituminous	3	N
MT	J. E. Corette	Subbituminous	1	N
KS	Quindaro	Subbituminous	2	N
NE	Sheldon	Subbituminous; Bituminous	2	N
IA	Riverside	Subbituminous	1	N
IA	Ottumwa	Subbituminous	1	N
MI	Belle River Power Plant	Subbituminous	2	N
IA	George Neal South	Subbituminous	1	N
IA	Ames Electric Services Power Plant	Subbituminous	2	N
WI	Edgewater	Subbituminous	3	N
MO	Rush Island	Subbituminous	2	N
IA	Council Bluffs (Walter Scott, Jr.)	Subbituminous	4	N
AR	Independence	Subbituminous	2	N
WI	Pulliam	Subbituminous	6	N
IA	George Neal North	Subbituminous	3	N
IN	State Line	Subbituminous	2	N
MN	Hoot Lake	Subbituminous	2	N
AZ	Irvington	Bituminous; Subbituminous	1	N
CO	Martin Drake	Subbituminous	2	N
CO	Ray D. Nixon	Subbituminous	1	N
MO	New Madrid	Subbituminous	2	N
MI	Presque Isle	Subbituminous	7	N
AR	White Bluff	Subbituminous	2	N
IL	Waukegan	Subbituminous	3	N
IL	Will County	Subbituminous; Bituminous	4	N

State	Facility Name	Coal rank	No. units	Scrubber
WY	Naughton	Subbituminous	3	N
IL	Joliet 29	Subbituminous	4	N
IL	Havana	Bituminous	1	N
TX	J. T. Deely	Subbituminous	2	N
OR	Boardman	Subbituminous; Bituminous	1	N
IL	Newton	Subbituminous; Bituminous	2	N
IL	Fisk	Subbituminous	1	N
IL	Joliet 9	Subbituminous	1	N
IA	Sutherland	Subbituminous	3	N
IL	Crawford	Subbituminous	2	N
IL	Powerton	Subbituminous; Bituminous	4	N
OH	Bay Shore	Subbituminous;Bituminous	3	N
KY	Pineville	Bituminous	1	N
IN	Michigan City	Subbituminous; Bituminous	1	N
IN	Dean H. Mitchell	Bituminous - Low Sulfur	4	N
LA	Rodemacher Power Station Unit #2	Subbituminous	1	N
TN	John Sevier Fossil Plant	Bituminous	4	N
MS	Victor J. Daniel, Jr.	Subbituminous; Bituminous	2	N
ND	R. M. Heskett Station	Lignite	1	N
IL	Hutsonville	Bituminous	2	N
IL	Kincaid Generation L.L.C.	Subbituminous; Bituminous	2	N
MO	Sikeston Power Station	Subbituminous	1	N
AL	James H. Miller, Jr.	Subbituminous; Bituminous	4	N
ND	Leland Olds Station	Lignite	2	N
IN	Warrick Power Plant	Bituminous - High Sulfur	1	N
NE	Whelan Energy Center	Subbituminous	1	N
OK	Hugo	Subbituminous	1	N
NE	Nebraska City	Subbituminous; Bituminous	1	N
OH	Richard H. Gorsuch	Bituminous	4	N
WI	Weston	Subbituminous	3	N
NE	Platte	Subbituminous	1	N
WY	Dave Johnston	Subbituminous	4	N
MA	Salem Harbor	Bituminous	3	N
IL	Joppa Steam	Subbituminous	6	N
WI	Bay Front Plant Generating	Bituminous	1	N
TX	Monticello	Lignite; Subbituminous	3	N
NE	North Omaha	Subbituminous	5	N
GA	Kraft	Bituminous	3	N
TX	W. A. Parish	Subbituminous	4	N
MO	Southwest Power Station	Subbituminous	1	N
AL	E. C. Gaston	Bituminous	5	N
UT	Carbon	Bituminous	2	N
OH	Picway	Bituminous	1	N
KY	Henderson 1	Bituminous	1	N
KY	Green River	Bituminous	2	N
GA	Mitchell	Bituminous	1	N
TX	Sam Seymour	Subbituminous	3	N
GA	Yates	Bituminous	7	N
IN	Frank E. Ratts	Bituminous	2	N
MI	St. Clair Power Plant	Bituminous; Subbituminous	6	N
TX	Big Brown	Lignite	2	N
GA	Scherer	Subbituminous; Bituminous	4	N

Attachment 5.

List of coal-fired electric utility steam generating units selected for dioxin/furan organic HAP testing

State	Facility Name	Coal rank	No. units	Equipped with ACI
KY	William C. Dale	Bituminous	4	
VA	Cogentrix of Richmond	Bituminous	8	
MI	J. H. Campbell	Bituminous; Subbituminous	3	
KS	Holcomb	Subbituminous	1	
VA	Bremo Power Station	Bituminous	2	
FL	Central Power and Lime, Inc.	Bituminous	1	
KY	H. L. Spurlock	Bituminous	3	
GA	Wansley	Bituminous	2	
FL	Crist	Bituminous	4	
TX	Gibbons Creek	Subbituminous	1	
FL	F. J. Gannon	Bituminous	6	
NC	Roxboro	Bituminous	6	
MS	Jack Watson	Bituminous	2	
TX	Sam Seymour	Subbituminous	3	
UT	Bonanza	Bituminous	1	
MI	J. C. Weadock	Subbituminous; Bituminous	2	
MO	James River Power Station	Bituminous; Subbituminous	3	
IA	Earl F. Wisdom	Bituminous	1	
OH	Lake Shore	Bituminous	1	
AL	Barry	Bituminous	5	
NC	G. G. Allen	Bituminous	5	
FL	Big Bend	Bituminous; Subbituminous	4	
FL	Polk Power	Subbituminous	IGCC	
NC	Cliffside	Bituminous	5	
MA	Somerset	Bituminous	1	
TN	Johnsonville Fossil Plant	Bituminous	10	
NC	Cape Fear	Bituminous	2	
NC	Tobaccoville Utility Plant	Bituminous	2	
KY	Ghent	Bituminous; Subbituminous	4	
OH	Kyger Creek	Bituminous	5	
OH	Miami Fort Station	Bituminous	5	
AL	Greene County	Bituminous	2	
FL	Lansing Smith	Bituminous	2	
CO	Arapahoe	Subbituminous	2	
MN	Silver Lake	Bituminous	1	
SC	W. S. Lee	Bituminous	3	
AL	Charles R. Lowman	Bituminous	3	
KY	John S. Cooper	Bituminous	2	
KY	Shawnee Fossil Plant	Bituminous; Subbituminous	10	
IL	Meredosia	Bituminous	5	

State	Facility Name	Coal rank	No. units	Equipped with ACI
WV	Mountaineer	Bituminous	1	
OH	Muskingum River	Bituminous	5	
VA	LG&E - Westmoreland Altavista	Bituminous	2	
VA	Mirant Potomac River	Bituminous	5	
MI	Dan E. Karn	Bituminous; Subbituminous	2	
MI	Marysville Power Plant	Bituminous	4	
MD	H. A. Wagner	Bituminous	2	
PA	Armstrong	Bituminous	2	
WI	Genoa	Bituminous; Subbituminous	1	
IN	Cayuga (IN)	Bituminous	2	
IL	Wood River	Bituminous	2	
WI	Alma	Bituminous; Subbituminous	2	
PA	Montour	Bituminous	2	
MO	Meramec	Bituminous; Subbituminous	4	
IL	Vermilion	Bituminous	2	
IN	R. M. Schahfer	Subbituminous; Bituminous	4	
VA	Mecklenburg Cogeneration Facility	Bituminous	2	
NJ	Deepwater	Bituminous	1	
PA	Brunner Island	Bituminous	3	
NC	Cogentrix Dwayne Collier Battle Cogen	Bituminous	4	
NC	Dan River	Bituminous	3	
GA	Bowen	Bituminous	4	
MI	River Rouge Power Plant	Bituminous; Subbituminous	2	
WV	Albright	Bituminous	3	
IA	Dubuque	Bituminous	3	
SC	Williams	Bituminous	1	
VA	LG&E - Westmoreland Southampton	Bituminous	2	
IN	Gibson Generating Station	Bituminous	5	
MO	Southwest Power Station	Subbituminous	1	
NY	AES Cayuga (formerly NYSEG Milliken)	Bituminous	2	
MI	Erickson	Bituminous; Subbituminous	1	
TN	Kingston Fossil Plant	Bituminous	9	
CT	AES Thames	Bituminous	2	
PA	Sunbury	Bituminous; Coal refuse	6	
NJ	Hudson	Bituminous	1	
GA	Hammond	Bituminous	4	
MO	Sioux	Bituminous; Subbituminous	2	
MI	J. R. Whiting	Bituminous; Subbituminous	3	
AL	James H. Miller, Jr.	Subbituminous; Bituminous	4	
VA	SEI - Birchwood Power Facility	Bituminous	1	

State	Facility Name	Coal rank	No. units	Equipped with ACI
VA	Chesapeake Energy Center	Bituminous	4	
IL	E. D. Edwards	Bituminous	3	
NC	Riverbend	Bituminous	4	
FL	Stanton Energy Center	Bituminous	2	
IA	Lansing	Bituminous; Subbituminous	2	
CO	Comanche	Subbituminous	2	
NC	Buck	Bituminous	5	
KY	Big Sandy	Bituminous	2	
VA	Glen Lyn	Bituminous	3	
OH	Walter C. Beckjord	Bituminous	6	
CA	Mt. Poso Cogeneration	Bituminous; Subbituminous	1	
NC	Belews Creek	Bituminous	2	
CO	Hayden	Bituminous	2	
TX	Tolk	Subbituminous	2	
MD	R. Paul Smith	Bituminous	2	
CO	Valmont	Bituminous	1	
WV	Fort Martin	Bituminous	2	
MD	Mirant Dickerson	Bituminous	3	
NC	Marshall	Bituminous	4	
NY	Danskammer Generating Station	Bituminous	2	
VA	Chesterfield Power Station	Bituminous	4	
NJ	Logan Generating Plant	Bituminous	1	
NC	Mayo	Bituminous	2	
MI	James De Young	Bituminous	1	
FL	Indiantown Cogeneration Facility	Bituminous	1	
MA	Mount Tom	Bituminous	1	
NC	H. F. Lee	Bituminous	3	
OH	Hamilton	Bituminous	2	
PA	Homer City	Bituminous	3	
MS	R. D. Morrow, Sr. Generating Plant	Bituminous	2	
MD	Brandon Shores	Bituminous	2	
SC	H. B. Robinson	Bituminous	1	
MI	Eckert Station	Bituminous; Subbituminous	6	
MI	TES Filer City Station	Bituminous	1	
AZ	Coronado	Subbituminous	2	
TX	Harrington Station	Subbituminous; Bituminous	3	
OH	Cardinal	Bituminous	3	
VA	LG&E - Westmoreland Hopewell	Bituminous	2	
CO	Cherokee	Bituminous	4	
GA	Scherer	Bituminous; Subbituminous	4	
NC	Asheville	Bituminous	2	
WI	Nelson Dewey	Subbituminous	2	
OH	Killen Station	Bituminous	1	
FL	Deerhaven Generating Station	Bituminous	1	
KY	East Bend Station	Bituminous	1	
SC	Cope	Bituminous	1	
FL	Crystal River	Bituminous	4	

State	Facility Name	Coal rank	No. units	Equipped with ACI
MI	Harbor Beach Power Plant	Bituminous	1	
OH	J. M. Stuart	Bituminous	4	
IN	Tanners Creek	Bituminous; Subbituminous	4	
IN	Clifty Creek	Bituminous	6	
AL	Widows Creek Fossil Plant	Bituminous	8	
NC	L.V. Sutton	Bituminous	3	
WV	John E. Amos	Bituminous	3	
WV	Mitchell	Bituminous	2	
FL	St. Johns River Power Park	Bituminous	2	
NC	W. H. Weatherspoon	Bituminous	3	
MI	Presque Isle	Subbituminous	3	ACI
IA	Council Bluffs (a.k.a., Walter Scott, Jr.) Unit 4	Subbituminous	1	ACI
MT	Hardin Generator Project	Subbituminous	1	ACI
WI	Weston Unit 4	Subbituminous	1	ACI
NM	San Juan Units 3, 4	Subbituminous	2	ACI
CT	Bridgeport Harbor Station	Bituminous	1	ACI
MA	Brayton Point	Bituminous	3	ACI
NJ	Mercer	Bituminous	2	ACI
NJ	B. L. England	Bituminous	1	ACI
NV	TS Power Plant	Subbituminous	1	ACI
DE	Indian River	Bituminous	3	ACI
DE	Edge Moor	Bituminous	2	ACI

Attachment 6.

List of coal-fired electric utility steam generating units selected for non-dioxin/furan organic HAP testing

State	Facility Name	Unit number	On-line year
AR	Plum Point Energy	1	2009
CO	Comanche	3	2009
IL	Dallman	34	2009
LA	Rodemacher Power Station	3	2009
NV	TS Power Plant	1	2009
TX	J. K. Spruce	BLR2	2009
TX	Oak Grove	1	2009
TX	Oak Grove	2	2009
TX	Sandow Station	5	2009
WI	South Oak Creek	1	2009
WY	Two Elk Generating Station	1	2009
CO	Lamar	4	2008
KY	H. L. Spurlock	4	2008
PA	River Hill Power Company LLC	31	2008
SC	Cross	4	2008
WI	Weston	4	2008
WY	Wygen II	1	2008
IA	Council Bluffs	4	2007
AZ	Springerville	3	2006
SC	Cross	3	2006
WI	Manitowoc	9	2006
KY	H. L. Spurlock	3	2005
MT	Hardin Generator Project	1	2005
PA	Seward	1	2004
PA	Seward	2	2004
IL	Marion	123	2003
WY	Wygen I	3	2003
FL	Northside Generating Station	1	2002
FL	Northside Generating Station	2	2002
MS	Red Hills Generating Facility	AA001	2002
MS	Red Hills Generating Facility	AA002	2002
PR	AES Puerto Rico (Aurora)	1	2002
PR	AES Puerto Rico (Aurora)	2	2002
MO	Hawthorn	5A	2001
MD	AES Warrior Run Cogeneration Facility	BLR1	2000
MI	B. C. Cobb	5	2000
OH	Bay Shore	1	2000
SC	Cogen South	B001	1999
FL	Stanton Energy Center	2	1996
VA	Birchwood Power	1A	1996
VA	Clover Power Station	2	1996
FL	Indiantown Cogeneration Facility	AAB01	1995
MT	Yellowstone Energy LP	BLR1	1995
MT	Yellowstone Energy LP	BLR2	1995
NC	Westmoreland-LG&E Roanoke Valley II	BLR2	1995
PA	Colver Power Project	ABB01	1995
PA	Northhampton Generating LP	BLR1	1995

State	Facility Name	Unit number	On-line year
SC	Cope	COP1	1995
SC	Cross	1	1995
VA	Clover Power Station	1	1995
WY	Neil Simpson II	2	1995
FL	Cedar Bay Generating LP	CBA	1994
FL	Cedar Bay Generating LP	CBB	1994
FL	Cedar Bay Generating LP	CBC	1994
NJ	Chambers Cogeneration LP	BOIL1	1994
NJ	Chambers Cogeneration LP	BOIL2	1994
NJ	Logan Generating Plant	B01	1994
NC	Westmoreland-LG&E Roanoke Valley I	BLR1	1994
PA	Scrubgrass Generating	UNIT 1	1993
PA	Scrubgrass Generating	UNIT 2	1993
UT	Sunnyside Cogen Associates	1	1993
HI	AES Hawaii	A	1992
HI	AES Hawaii	B	1992
LA	R. S. Nelson	2A	1992
LA	R. S. Nelson	1A	1992
PA	Panther Creek Energy Facility	BLR1	1992
PA	Panther Creek Energy Facility	BLR2	1992
PA	Piney Creek Project	BRBR1	1992
TX	J. K. Spruce	BLR1	1992
VA	Altavista Power Station	1	1992
VA	Cogentrix of Richmond	1A	1992
VA	Cogentrix of Richmond	1B	1992
VA	Cogentrix of Richmond	2A	1992
VA	Cogentrix of Richmond	2B	1992
VA	Cogentrix of Richmond	3A	1992
VA	Cogentrix of Richmond	3B	1992
VA	Cogentrix of Richmond	4A	1992
VA	Cogentrix of Richmond	4B	1992
VA	Mecklenburg Cogeneration Facility	BLR1	1992
VA	Mecklenburg Cogeneration Facility	BLR2	1992
VA	Southampton Power Station	1	1992
WV	Grant Town Power Plant	BLR1A	1992
WV	Grant Town Power Plant	BLR1B	1992
WV	North Branch	1A	1992
WV	North Branch	1B	1992
AL	James H. Miller, Jr.	4	1991
CO	Nucla	1	1991
MD	Brandon Shores	2	1991
OH	W. H. Zimmer Generating Station	1	1991
OK	AES Shady Point	1A	1991
OK	AES Shady Point	1B	1991
OK	AES Shady Point	2A	1991
OK	AES Shady Point	2B	1991
PA	Cambria Cogen	B1	1991
PA	Cambria Cogen	B2	1991
TX	Twin Oaks Power Station (formerly TNP-One)	U2	1991
WV	Morgantown Energy Facility	CFB1	1991
WV	Morgantown Energy Facility	CFB2	1991
AZ	Springerville	2	1990

State	Facility Name	Unit number	On-line year
CA	ACE Cogeneration Facility	CFB	1990
CT	AES Thames	A	1990
CT	AES Thames	B	1990
KY	Shawnee Fossil Plant	10	1990
KY	Trimble County	1	1990
ME	Rumford Cogeneration	6	1990
ME	Rumford Cogeneration	7	1990
MI	TES Filer City Station	1	1990
MI	TES Filer City Station	2	1990
MT	Colstrip Energy LP	BLR1	1990
NC	Cogentrix Dwayne Collier Battle Cogen	1A	1990
NC	Cogentrix Dwayne Collier Battle Cogen	1B	1990
NC	Cogentrix Dwayne Collier Battle Cogen	2A	1990
NC	Cogentrix Dwayne Collier Battle Cogen	2B	1990
PA	Ebensburg Power	031	1990
PA	Foster Wheeler Mt. Carmel Cogen	SG-101	1990
PA	St. Nicholas Cogeneration Project	1	1990
TX	Twin Oaks Power Station (formerly TNP-One)	U1	1990
AL	James H. Miller, Jr.	3	1989
CA	Mt. Poso Cogeneration	BL01	1989
CA	Rio Bravo Jasmin	CFB	1989
CA	Rio Bravo Poso	CFB	1989
GA	Scherer	4	1989
IN	Rockport	MB2	1989
PA	Kline Township Cogen Facility	1	1989
PA	P. H. Glatfelter	5PB036	1989
CA	Stockton Cogen	BLR1	1988
FL	Central Power and Lime, Inc.	1	1988
FL	St. Johns River Power Park	2	1988
PA	John B. Rich Memorial Power Station	CFB1	1988
PA	John B. Rich Memorial Power Station	CFB2	1988
PA	Wheelabrator Frackville Energy	BLR1	1988
TX	Fayette Power Project	3	1988
FL	St. Johns River Power Park	1	1987
FL	Stanton Energy Center	1	1987
GA	Scherer	3	1987
MN	Sherburne County Generating Plant	3	1987
NY	Danskammer Generating Station	3	1987
NY	Danskammer Generating Station	4	1987
PA	AES Beaver Valley Partners Beaver Valley	2	1987
PA	AES Beaver Valley Partners Beaver Valley	3	1987
PA	AES Beaver Valley Partners Beaver Valley	4	1987
PA	WPS Westwood Generation LLC	031	1987
SC	Stone Container Florence Mill	PB4	1987
UT	Intermountain Power Project	2SGA	1987
IN	A. B. Brown	2	1986
IN	Petersburg	4	1986
IN	R. M. Schahfer	18	1986
KY	D. B. Wilson	W1	1986
LA	Dolet Hills Power Station	1	1986
MT	Colstrip	4	1986
ND	Antelope Valley	B2	1986

State	Facility Name	Unit number	On-line year
OK	GRDA	2	1986
PA	Chester Operations	10	1986
TX	AES Deepwater	AAB001	1986
TX	Limestone	LIM2	1986
TX	Oklaunion	1	1986
UT	Bonanza	1-1	1986
UT	Intermountain Power Project	1SGA	1986
AL	James H. Miller, Jr.	2	1985
AL	Mobile Energy Services LLC	7PB	1985
AZ	Springerville	1	1985
AR	Independence	2	1985
FL	Big Bend	BB04	1985
MI	Belle River Power Plant	2	1985
NV	North Valmy Generating Station	2	1985
TX	Limestone	LIM1	1985
TX	H. W. Pirkey	1	1985
TX	Tolk	172B	1985
WI	Edgewater	5	1985
WI	Pleasant Prairie	2	1985
CO	Craig	C3	1984
CO	Rawhide	101	1984
FL	Crystal River	5	1984
FL	Seminole	1	1984
FL	Seminole	2	1984
GA	Scherer	2	1984
IN	Rockport	MB1	1984
KY	Ghent	4	1984
LA	Big Cajun 2	2B3	1984
MD	Brandon Shores	1	1984
MI	Belle River Power Plant	1	1984
MT	Colstrip	3	1984
NM	Escalante	1	1984
NY	AES Somerset LLC	1	1984
ND	Antelope Valley	B1	1984
OK	Muskogee	6	1984
SC	Cross	2	1984
AR	Independence	1	1983
IN	Merom	1SG1	1983
IN	R. M. Schahfer	17	1983
IA	Louisa	101	1983
IA	Muscatine Plant #1	9	1983
KS	Holcomb	SGU1	1983
KS	Jeffrey Energy Center	3	1983
MI	J. B. Sims	3	1983
MI	Shiras	3	1983
NV	Reid Gardner	4	1983
NC	Mayo	1A	1983
NC	Mayo	1B	1983
TX	Gibbons Creek	1	1983
UT	Hunter	3	1983
FL	C. D. McIntosh, Jr.	3	1982
FL	Crystal River	4	1982

State	Facility Name	Unit number	On-line year
GA	Scherer	1	1982
IL	Newton	2	1982
IN	Gibson Generating Station	5	1982
IN	Merom	2SG1	1982
IA	Ames Electric Services Power Plant	8	1982
KY	Mill Creek	4	1982
LA	R. S. Nelson	6	1982
LA	Rodemacher Power Station	2	1982
MI	Endicott Station	1	1982
MO	Thomas Hill	MB3	1982
NE	Gerald Gentleman Station	2	1982
NE	Platte	1	1982
NM	San Juan	4	1982
ND	Stanton Station	10	1982
OH	Killen Station	2	1982
OK	GRDA	1	1982
OK	Hugo	1	1982
TX	San Miguel	SM-1	1982
TX	Tolk	171B	1982
TX	W. A. Parish	WAP8	1982
TX	Welsh	3	1982
WY	Laramie River Station	3	1982
AZ	Cholla	4	1981
AR	White Bluff	2	1981
CO	Pawnee	1	1981
FL	Deerhaven Generating Station	B2	1981
IA	Ottumwa	1	1981
KS	Nearman Creek	N1	1981
KY	East Bend Station	2	1981
KY	Ghent	3	1981
KY	H. L. Spurlock	2	1981
KY	R. D. Green	G2	1981
LA	Big Cajun 2	2B2	1981
MS	Victor J. Daniel, Jr.	2	1981
MO	Sikeston Power Station	1	1981
NE	Whelan Energy Center	1	1981
NV	North Valmy Generating Station	1	1981
ND	Coal Creek	2	1981
ND	Coyote	B1	1981
SC	Winyah	4	1981
TX	Sandow Station	4	1981
WI	Weston	3	1981
WY	Laramie River Station	2	1981
AL	Charles R. Lowman	3	1980
AZ	Cholla	3	1980
AZ	Coronado	U2B	1980
AR	White Bluff	1	1980
CO	Craig	C1	1980
CO	Ray D. Nixon	1	1980
DE	Indian River	4	1980
KS	Jeffrey Energy Center	2	1980
LA	Big Cajun 2	2B1	1980

Attachment 8.

List of oil-fired electric utility steam generating units

State	Facility Name	No. Units
CT	Bridgeport Harbor Station	1
CT	Devon	2
CT	Middletown	3
CT	Montville	2
CT	New Haven Harbor	1
CT	Norwalk Harbor Station	2
DC	Benning	2
DE	Edge Moor	1
DE	McKee Run	3
FL	Anclote	2
FL	C. D. McIntosh, Jr.	2
FL	Cape Canaveral	2
FL	Indian River	3
FL	Manatee	2
FL	Martin	2
FL	Northside Generating Station	1
FL	P. L. Bartow	3
FL	Port Everglades	4
FL	Riviera	2
FL	Sanford	1
FL	Suwannee River	3
FL	Turkey Point	2
GA	McManus	2
GU	Cabras	2
GU	Tanguisson Power Plant	1
HI	Honolulu	2
HI	Kahe	6
HI	Waiau	6
IL	Havana	8
IL	Meredosia	1
IN	Edwardsport	1
IN	Harding Street Station (a.k.a., E. W. Stout Generating Station)	2

**STANDARD FORM 83-I SUPPORTING STATEMENT
FOR OMB REVIEW OF EPA ICR No. 2362.01:**

**INFORMATION COLLECTION REQUEST FOR NATIONAL EMMISION
STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAP) FOR COAL- AND
OIL-FIRED ELECTRIC UTILITY STEAM GENERATING UNITS**

Sector Policies and Programs Division
U.S. Environmental Protection Agency
Research Triangle Park, North Carolina 27711

June 17, 2009

Attachment 2.

Industry Burden and Costs for Responding to the Questionnaire

Activity	(A) Hours per Occurrence	(B) Occurrences/ Respondent/Year	(C) Hours/ Respondent/ Year (A x B)	(D) Respondents/ Year	(E) Technical Hours/Year (C x D)	(F) Managerial Hours/Year (E x 0.05)*	(G) Clerical Hours/Year (E x 0.10)	(F) Cost/ Year
1. APPLICATIONS (Not Applicable)								
2. SURVEY AND STUDIES (Not Applicable)								
3. ACQUISITION, INSTALLATION, AND UTILIZATION OF TECHNOLOGY AND SYSTEMS (Not Applicable)								
4. REPORT REQUIREMENTS								
A. Read Instructions								
Facility	2	1	2	555	1,110.0	55.5	111.0	$120,048
B. Required Activities								
Gather existing reports with requested data	8	1	8	1325	10,600.0	530.0	1,060.0	$1,146,401
Extract requested data from reports	8	1	8	1325	10,600.0	530.0	1,060.0	$1,146,401
Enter extracted data into Web Site	16	1	16	1325	21,200.0	1,060.0	2,120.0	$2,292,802
QA/QC entered data on Web Site	8	1	8	1325	10,600.0	530.0	1,060.0	$1,146,401
Read Test Plan provided by EPA for stack testing	0.7	1	0.7	471	329.7	16.5	33.0	$95,657
Procure contractor to perform testing	20	1	20	471	9,420.0	471.0	942.0	$1,018,783
Submit stack test results through the ERT	2	1	2	471	942.0	47.1	94.2	$101,878
QA/QC entered data on Web Site	1	1	1	471	471.0	23.6	47.1	$50,939
HCl and HF testing from coal-fired utility units (w/ and w/o FGD)**		217						$8,246,000
Dioxin/furan emissions from coal-fired utility units**		149						$7,450,000
Non-Dioxin/furan emissions (CO, VOC, and THC) from coal-fired utility units**		184						$19,688,000
Hg and non-Hg Metalic HAPs from coal-fired utility units**		214						$74,824,000
All HAP surrogates from oil-fired utility units**		116						$35,032,000
Plant personnel for testing***	16	3	48	471	22,608.0	226.1	-	$2,232,193
Review the Test Report Data	5	1	5	471	2,355.0	117.8	-	$275,954
C. Create Information (Included in 4B)								
D. Gather Existing Information (Included in 4E)								
E. Write Report (Not Applicable)								
5. RECORDKEEPING REQUIREMENTS (Not applicable)								
TOTAL ANNUAL LABOR BURDEN AND COST					90,236	3,607	6,527	$104,807,458
						100,370	Hours	
ANNUAL CAPITAL COSTS (Not Applicable)								$ -
ANNUALIZED CAPITAL COSTS (Not Applicable)								$ -
TOTAL ANNUAL COSTS (O&M) (Not Applicable)								$ -
TOTAL ANNUALIZED COSTS (Annualized capital + O&M costs) (Not Applicable)								$ -

*We assumed no clerical hours and less managerial hours were needed when plant personnel were working with Contractors to conduct testing

**This is the assumed testing costs for facilities when testing is performed by a Contractor

***This assumes 3 facility technical staff over 2 days for working with the Contractor to conduct testing. All administrative work is assumed to be included in the contractor testing and no facility administrative staff is required for testing.

Attachment 3.

Agency Burden and Costs

Activity	(A) EPA Hours/ Occurrence	(B) Occurrences/ Plant/Year	(C) EPA Hours/ Plant/Year (A x B)	(D) Plants/ Year	(E) EPA Technical Hours/ Year (C x D)	(F) EPA Managerial Hours/Year	(G) EPA Clerical Hours/Year	(H) Cost, $
Develop questionnaire	80	1	80	1	80.0	4.0	8.0	$ 4,838
Develop web site for data entry from facilities	120	1	120	1	120.0	6.0	12.0	$ 7,257
Mail out Questionnaire	4	1	4	555	2,220.0	111.0	222.0	$ 134,250
Answer respondent questions	0.25	1	0.25	55.5	13.9	0.7	1.4	$ 839
Analysis request for confidentiality	0.25	1	0.25	132.5	33.1	1.7	3.3	$ 2,003
Review and Analyze responses	4	1	4	1325	5,300.0	265.0	530.0	$ 320,506
Review the electronically submitted stack testing data	5	1	5	880	4,400.0	220.0	440.0	$ 266,080
Total Annual Hours					12,167	608.35	1,217	$ 735,773
						13,992	hours	
Expenses								
Printing Questionnaire	$ 694							
Postage to mail Questionnaire Registered Mail/Receipt	$ 6,771							
Computer Storage of data and web interface	$ 1,200							
Total Expenses								$ 8,665
								$ 744,437

~~We assume that EPA will mail one questionnaire to each facility.~~
Assumes that 10% of the facilities will have questions
Assumes that 10% of the units will have confidential data

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Colleen M. Castille
Secretary

STATE OF FLORIDA
INDUSTRIAL WASTEWATER FACILITY PERMIT

PERMITTEE:

FP&L Cape Canaveral Plant
6000 North U.S. Highway 1
Cocoa, FL 32927

PERMIT NUMBER:	FL0001473 (Major)
PA FILE NUMBER:	FL0001473-008-IW1S
ISSUANCE DATE:	August 10, 2005
EXPIRATION DATE:	August 9, 2010

RESPONSIBLE AUTHORITY:

Mr. Lowell Trotter
Plant General Manager

FACILITY:

FP&L Cape Canaveral Plant
6000 North U.S. Highway 1
Cocoa, FL 32927
Brevard County

Latitude: 28° 28' 10" N Longitude: 80° 45' 54" W

This permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.) and applicable rules of the Florida Administrative Code (F.A.C.), and constitutes authorization to discharge to waters of the state under the National Pollutant Discharge Elimination System (NPDES). The above named permittee is hereby authorized to operate the facilities shown on the application and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

The plant consists of two steam electric generating units. Units 1 and 2 have a nominal generating capacity of 400 megawatts.

The plant uses a once-through condenser cooling water system. Condenser cooling water is drawn from the Indian River through an intake canal located on the southern end of the plant. The cooling water passes through the plant condensers and then discharged back to the Indian River via two 78-inch underground pipes that empty into their respective outfall structures. The discharge structures for the two units are located approximately 550 feet apart. Auxiliary equipment cooling water from both units is discharged to the Indian River through a single 18-inch outfall pipe located approximately midway between the once-through cooling outfall structures.

The main condenser Once-Through Cooling Water (OTCW) is chlorinated at the intake for both units. The facility dechlorinates the once-through cooling water using sodium bisulfite prior to discharge. Auxiliary Equipment Cooling Water (AECW) may also be chlorinated using continuous low level chlorination. Boiler blowdown is captured and reused. Wastewater from the on-site water treatment system is discharged via existing Outfall D-030 to the Indian River until 6 months beyond the issuance date of this permit. After such time, wastewater from the on-site

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 15
COMPANY Florida Power & Light Company (Direct)
WITNESS R. R. Labauve (RRL-10) (Previously RRL-6)
DATE 11/02/09

PERMITTEE:		PERMIT NUMBER:	FL0001473
FP&L Cape Canaveral Plant 6000 North U.S. Highway 1 Cocoa, FL 32927		Issuance date: Expiration date:	August 10, 2005 August 9, 2010

water treatment system will be discharged internally to the ABCW outfall or, alternatively, to the OTCW outfalls.

WASTEWATER TREATMENT:
Wastewater generated during metal cleaning operations is discharge to the two lined Solids Settling Basins (B-1A and B-1B). Reverse osmosis reject from boiler blowdown source water and boiler chemical cleaning rinses (in which EDTA, Citro-Solv or equivalent cleaner is used in the cleaning operation) may also be routed to the solids settling basins. The wastewater in the basins is treated by adding caustic that allows for the precipitation of metals followed by sedimentation. Treated effluent from the solids settling basins is routed to the Evaporation/Percolation Basin (BP-1) and acid is added for pH adjustment. Treated wastewater from the evaporation/percolation basin is used for spray irrigation on the berms of the fuel oil containment area. This area is designated as E/P Basin Spray Area (SP-1).

Stormwater runoff and drainage from equipment areas and fuel oil handling facilities as well as equipment rinse water in the power block areas are collected via floor drains. The collected runoff is then routed through oil removal devices prior to discharge to the equipment area runoff treatment and disposal system consisting of the Forwarding Sump (S-3), Equipment Area Runoff Basin (B-3), organo-clay polishing filters, and the Runoff Disposal Area (DA-1). Under light rainfall conditions, runoff from the forwarding sump is routed through the organo-clay filters directly to the Disposal Area DA-1. Under medium and chronic rainfall conditions (up to one inch of rainfall), the runoff from the forwarding sump is routed to the Runoff Basin B-3 and then pumped through the organo-clay filters to the runoff Disposal Area DA-1. On rare occasions and under chronic heavy rainfall conditions (in excess of one inch rainfall), the runoff that is not routed to the runoff basin or pumped through the organo-clay filters to the runoff disposal area, overflows at the forwarding sump and discharged to the Indian River via Outfall D-016.

EFFLUENT DISPOSAL:

Surface Water Discharge:

An existing discharge of 332 MGD annual average flow and 396 MGD maximum daily flow to Indian River (Class III Marine waters), D-011. The once-through cooling water from Unit 1 is located approximately at latitude 28° 28' 11" N, longitude 80° 45' 46" W.

An existing discharge of 332 MGD annual average flow and 396 MGD maximum daily flow to Indian River (Class III Marine waters), D-012. The once-through cooling water outfall from Unit 2 is located approximately at latitude 28° 28' 14" N, longitude 80° 45' 50" W.

An existing discharge of 13.8 MGD annual average flow and 30.0 MGD maximum daily flow to the Indian River (Class III Marine waters), D-015. The auxiliary equipment cooling water outfall for Units 1 & 2 line is located approximately at latitude 28° 28' 12" N, longitude 80° 45' 48" W.

An existing discharge to Indian River (Class III Marine waters), D-016. The equipment area runoff basin overflow outfall is located approximately at latitude 28° 28' 18" N, longitude 80° 45' 51" W.

An existing discharge to Indian river (Class III Marine waters), D-028. The stormwater from fuel oil storage tank secondary containment area outfall is located approximately at latitude 28° 28' 18" N, longitude 80° 45' 51" W.

An existing discharge to Indian River (Class III Marine waters), D-029. The non-equipment area stormwater outfall is located approximately at latitude 28° 28' 12" N, longitude 80° 45' 48" W.

PERMITTEE:		PERMIT NUMBER:	FL0001473
FP&L Cape Canaveral Plant 6000 North U.S. Highway 1 Cocoa, FL 32927		Issuance date: Expiration date:	August 10, 2005 August 9, 2010

An existing discharge to Indian River (Class III Marine waters), D-030. The water treatment system wastewater outfall is located approximately at latitude 28° 28' 18" N, longitude 80° 45' 51" W.

Land Application:

An existing land application system (G-010) consisting of Evaporation/Percolation Basin (EP-1) and E/P Basin Spray Area (SP-1). The Evaporation/Percolation Basin (EP-1) is located approximately at latitude 28° 28' 14" N, longitude 80° 45' 51" W. The E/P Basin Spray Area (SP-1) is located approximately at latitude 28° 28' 16" N, longitude 80° 45' 53" W.

An existing land application system (G-020) consisting of Equipment Area Runoff Basin (B-3) and Runoff Disposal Area (DA-1). The Equipment Area Runoff Basin (B-3) is located approximately at latitude 28° 28' 10" N, longitude 80° 45' 54" W. The Runoff Disposal Area (DA-1) is located approximately at latitude 28° 28' 08" N, longitude 80° 45' 55" W.

Internal Outfalls:

This permit authorizes discharge of 0.05 MGD annual average flow from internal Outfall I-017 to the AECW Outfall (D-015) or, alternatively, to the OTCW Outfalls (D-011 and D-012).

IN ACCORDANCE WITH: The limitations, monitoring requirements and other conditions as set forth in Part I through Part VIII on pages 4 through 26 of this permit.

PERMITTEE: PERMIT NUMBER: FL0001473

FP&L Cape Canaveral Plant
6000 North U.S. Highway 1
Cocoa, FL 32927

Issuance date: August 10, 2005
Expiration date: August 9, 2010

I. Effluent Limitations and Monitoring Requirements

A. Surface Water Discharges

1. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **Once-Through Cooling Water (OTCW)** from **Outfalls D-011 and D-012.** Such discharge shall be limited and monitored by the permittee as specified below:

	Discharge Limitations				Monitoring Requirements		
Parameters (units)	**Monthly Average**	**Instantaneous Maximum**	**Maximum Daily Average**	**Instantaneous Minimum**	**Monitoring Frequency**	**Sample Type**	**Sample Point**
Flow (MGD)	Report	Report	--	--	Continuous	Calculated	FLW-1, FLW-2
Chlorination (HOURS/UNIT/DAY)	--	2.0	--	--	Daily	Calculated	OTH-1, OTH-2
Oxidants, Total Residual (MG/L)	--	--	0.01	--	Weekly	Grab[1]	EFF-1, EFF-2
Temperature (F), Water (DEG.F)	Report[2]	Report[2]	--	--	6/Day	Instantaneous	EFF-1, EFF-2
Dissolved Oxygen (MG/L)	--	--	--	Report	Monthly[3]	Grab	INT-1 and EFF-1 or INT-2 and EFF-2

2. Effluent samples shall be taken at the monitoring site locations listed above and as described below:

Sample Point	Description of Monitoring Location
FLW-1, FLW-2	Once-through cooling water intake for Units 1 and 2, respectively, flow monitoring location.
EFF-1, EFF-2	Once-through cooling water discharge structures for Units 1 and 2, respectively.
INT-1, INT-2	Once-through or auxiliary equipment cooling water for Units 1 and 2, respectively.
OTH-1, OTH-2	At the point of chlorine addition for Units 1 and 2, OTCW

[1] Grab samples shall consist of multiple samples collected at approximately the beginning, middle, and end of the chlorination period.
[2] Discharge from Outfall D-001 is subject to thermal limitations established by Rule 62-302.520(1), F.A.C.
[3] Grab samples for both the intake and discharge shall be taken concurrently every 4 hours, for 24 hours, once month. Intake and discharge sampling during a monthly sampling event is only required from one power plant unit, i.e. Unit 1 or Unit 2. The permittee may request a reduction or discontinuance of these monitoring requirements after 12 months of monitoring.

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FP&L Cape Canaveral Plant 6000 North U.S. Highway 1 Cocoa, FL 32927	Issuance date: Expiration date:	August 10, 2005 August 9, 2010

3. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **Auxiliary Equipment Cooling Water (AECW) from Units 1 and 2 used in lieu of OTCW** from Outfall D-013 (formerly D-0D1) and Outfall D-014 (formerly D-0D2). Such discharge shall be limited and monitored by the permittee as specified below:

	Discharge Limitations			Monitoring Requirements		
Parameters (units)	**Monthly Average**	**Maximum Daily Average**	**Instantaneous Maximum**	**Monitoring Frequency**	**Sample Type**	**Sample Point**
Flow (MGD)	Report	Report	--	Continuous	Calculated	FLW-3 FLW-4
Temp. Diff. between Intake and Discharge (DEG.F)	--	--	20.0	6/Day	Calculated	INT-1 INT-2 EFF-1 EFF-2
Oxidants, Total Residual (MG/L)	--	0.01		Weekly	Grab[4]	EFF-1 EFF-2
Chlorination (HOURS/UNIT/DAY)	--	24	--	Daily	Calculated	OTH-3

4. Effluent samples shall be taken at the monitoring site locations listed above and as described below:

Sample Point	Description of Monitoring Location
FLW-3, FLW-4	Auxiliary equipment cooling water intake for Units 1 and 2, respectively, flow monitoring location.
INT-1, INT-2	Once-through or auxiliary equipment cooling water intake for Units 1 and 2, respectively.
EFF-1, EFF-2	Once-through cooling water discharge structures for Units 1 and 2, respectively.
OTH-3	At the point of chlorine addition for Units 1 and 2 AECW

[4] Multiple grabs shall be collected during daylight hours every 4 hours during TRO discharge.

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FP&L Cape Canaveral Plant 6000 North U.S. Highway 1 Cocoa, FL 32927	Issuance date: Expiration date:	August 10, 2005 August 9, 2010

5. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **Units 1 and 2 Auxiliary Equipment Cooling Water** from Outfall D-015 (formerly D-081). Such discharge shall be limited and monitored by the permittee as specified below:

	Discharge Limitations			Monitoring Requirements		
Parameters (units)	**Monthly Average**	**Maximum Daily Average**	**Instantaneous Maximum**	**Monitoring Frequency**	**Sample Type**	**Sample Point**
Flow (MGD)	Report	Report	--	Continuous	Calculated	FLW-3 FLW-4
Oxidants, Total Residual (MG/L)	--	0.01	--	Weekly	Grab[5]	EFF-3
Chlorination (HOURS/UNIT/DAY)	--	24	--	Daily	Calculated	OTH-3

6. Effluent samples shall be taken at the monitoring site locations listed above and as described below:

Sample Point	Description of Monitoring Location
FLW-3, FLW-4	Flow monitoring location for auxiliary equipment cooling water for Units 1 and 2, respectively.
OTH-3	At the point of chlorine addition for Units 1 and 2 ABCW
EFF-3	Combined auxiliary equipment water cooling discharge from Units 1 and 2 prior to actual discharge to the receiving waters or mixing with other waste streams

[5] Multiple grabs shall be collected during daylight hours every 4 hours during TRO discharge.

PERMITTEE:	PERMIT NUMBER: FL0001473
FP&L Cape Canaveral Plant 6000 North U.S. Highway 1 Cocoa, FL 32927	Issuance date: August 10, 2005 Expiration date: August 9, 2010

7. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to **Equipment Area Runoff Basin Overflow** from Outfall D-016 (formerly D-0B0). Such discharge shall be limited and monitored by the permittee as specified below:

	Discharge Limitations			Monitoring Requirements		
Parameters (units)	Monthly Average	Maximum Daily Average	Instantaneous (Min/Max)	Monitoring Frequency	Sample Type	Sample Point
Flow (MGD)	Report	Report	--	Per Discharge[6]	Calculated	EFF-4
Oil & Grease (MG/L)	Report	5.0	--	Per Discharge[6]	Grab	EFF-4
Solids, Total Suspended (MG/L)	30.0	100.0	--	Per Discharge[6]	Grab	EFF-4
pH Range (SU)	--	--	6.0 to 9.0	Per Discharge[6]	Grab	EFF-4

8. Effluent samples shall be taken at the monitoring site locations listed above and as described below:

Sample Point	Description of Monitoring Location
EFF-4	Discharge from the forwarding sump prior to actual discharge to receiving waters or mixing with other waste stream.

9. During the period beginning on the issuance date and lasting until 6 months beyond the issuance date, the permittee is authorized to discharge Water Treatment Plant Wastewater from existing Outfall D-030 to the Indian River. Such discharge shall be limited and monitored by the permittee as specified below:

Parameters (units)	Monthly Average	Maximum Daily Average	Instantaneous	Annual Average	Monitoring Frequency	Sample Type	Sample Point
Flow (MGD)	Report	Report	--	--	2/Month	Calculated	EFF-5
Solids, Total Suspended (MG/L)	30.0	100.0	--	--	2/Month	Composite[7]	EFF-5
Oil and Grease (MG/L)	--	5.0	--	--	2/Month	Grab	EFF-5
pH Range (S.U.)	--	--	6.0 to 9.0	--	2/Month	Grab	EFF-5

[6] Monitoring of discharge from the Oil separator/Forwarding Sump is not required provided the first one inch rainfall is retained by the Stormwater Basin and associated spray field. Subsequent overflow may be discharged without monitoring requirements, except that there shall be no discharge of a visible oil sheen. In the event that these conditions are not met, monitoring shall be 1/discharge.

[7] Shall be defined as a composite of grab samples taken at the beginning, middle and end of the Backwash Basin discharge period.

PERMITTEE:	PERMIT NUMBER:	FL0001473
FP&L Cape Canaveral Plant 6000 North U.S. Highway 1 Cocoa, FL 32927	Issuance date: Expiration date:	August 10, 2005 August 9, 2010

10. Effluent samples shall be taken at the monitoring site locations listed above and as described below:

Sample Point	Description of Monitoring Location
EFF-5	At the point of discharge to the receiving waters.

11. During the period beginning at initiation of discharge and lasting through the expiration date of this permit, the permittee is authorized to discharge Water Treatment Plant Wastewater from Outfall I-017 to the ABCW Outfall (D-015) or to the OTCW Outfalls (D-011 and D-012). Such discharge shall be limited and monitored by the permittee as specified below:

Parameters (units)	Monthly Average	Maximum Daily Average	Instantaneous	Annual Average	Monitoring Frequency	Sample Type	Sample Point
Flow (MGD)	Report	Report	--	--	2/Month	Calculated	OUI-1
Solids, Total Suspended (MG/L)	30.0	100.0	--	--	2/Month	Grab	OUI-1
Oil and Grease (MG/L)	15.0	20.0	--	--	2/Month	Grab	OUI-1
pH Range (S.U.)	--	--	6.0 to 9.0	--	2/Month	Grab	OUI-1
Nitrogen, Total as N (LBS/DAY)	--	--	--	7.0	Monthly	Grab	OUI-1
Phosphorus, Total as P, (LBS/DAY)	--	--	--	0.4	Monthly	Grab	OUI-1

12. Effluent samples shall be taken at the monitoring site locations listed above and as described below:

Sample Point	Description of Monitoring Location
OUI-1	At the point of discharge to the ABCW or OTCW conduits.

13. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge from Outfall D-028 (formerly D-0B), stormwater from the fuel oil storage tank secondary containment area, provided such discharges are limited and monitored by the permittee as specified below:

    a. The facility shall have a valid Spill Prevention Control and Countermeasure (SPCC) Plan pursuant to 40 CFR Part 112.

    b. The facility shall endeavor to retain the stormwater in the containment area to the maximum extent practicable before discharging from Outfall D-028. The discharge from Outfall D-028 shall only occur due to tank and equipment integrity and safety concerns.

    c. In draining the diked area, a portable oil skimmer or similar device or absorbent material shall be used to remove oil and grease (as indicated by the presence of a sheen) immediately prior to draining.

    d. Monitoring records shall be maintained in the form of a log and shall contain the following information, as a minimum:

- Date and time of discharge;
- Estimated volume of discharge;
- Initials of person making visual inspection and authorizing discharge; and
- Observed conditions of storm water discharged.

e. There shall be no discharge of floating solids or visible foam in other than trace amounts and no discharge of a visible oil sheen at any time.

14. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge Outfall D-029 (formerly D-0S0), non-equipment area stormwater. Discharge of non-equipment area stormwater is permitted without limitation or monitoring requirements.
15. OTCW and ABCW limitations and monitoring requirements for TRO are not applicable for any week in which chlorine is not added to Units 1 or 2.
16. Intake Screen wash water may be discharged without limitation or monitoring requirements, except that there shall be no discharge of a visible sheen.
17. There shall be no discharge of floating solids or visible foam in other than trace amounts.
18. The discharge shall not cause a visible sheen on the receiving water.

B. Underground Injection Control Systems

1. This section is not applicable to this facility.

C. Land Application Systems

1. The discharge from land application systems G-010 and G-020 is authorized without limitations or monitoring requirements.

D. Other Methods of Disposal or Recycling

1. There shall be no discharge of industrial wastewater from this facility to ground or surface waters, except as authorized by this permit.

E. Other Limitations and Monitoring and Reporting Requirements

1. The sample collection, analytical test methods and method detection limits (MDLs) applicable to this permit shall be in accordance with Rule 62-4.246, Chapters 62-160 and 62-601, F.A.C., and 40 CFR 136, as appropriate. The list of Department established analytical methods, and corresponding MDLs (method detection limits) and PQLs (practical quantification limits), which is titled "Florida Department of Environmental Protection Table as Required By Rule 62-4.246(4) Testing Methods for Discharges to Surface Water" dated June 21, 1996, is available from the Department on request. The MDLs and PQLs as described in this list shall constitute the minimum acceptable MDL/PQL values and the Department shall not accept results for which the laboratory's MDLs or PQLs are greater than those described above unless alternate MDLs and/or PQLs have been specifically approved by the Department for this permit. Any method included in the list may be used for reporting as long as it meets the following requirements:

   a. The laboratory's reported MDL and PQL values for the particular method must be equal or less than the corresponding method values specified in the Department's approved MDL and PQL list;

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b. The laboratory reported PQL for the specific parameter is less than or equal to the permit limit or the applicable water quality criteria, if any, stated in Chapter 62-302, F.A.C. Parameters that are listed as "report only" in the permit shall use methods that provide a PQL, which is equal to or less than the applicable water quality criteria stated in 62-302 FAC; and

c. If the PQLs for all methods available in the approved list are above the stated permit limit or applicable water quality criteria for that parameter, then the method with the lowest stated PQL shall be used.

Where the analytical results are below method detection or practical quantification limits, the permittee shall report the actual laboratory MDL and/or PQL values for the analyses that were performed following the instructions on the applicable discharge monitoring report. Approval of alternate laboratory MDLs or PQLs are not necessary if the laboratory reported MDLs and PQLs are less than or equal to the permit limit or the applicable water quality criteria, if any, stated in Chapter 62-302, F.A.C. However, where necessary, the permittee may request approval for alternative methods or for alternative MDLs and PQLs for any approved analytical method, in accordance with the criteria of Rules 62-160.520 and 62-160.530, F.A.C.

2. Parameters which must be monitored as a result of a surface water discharge shall be analyzed using a sufficiently sensitive method in accordance with 40 CFR Part 136.

3. Monitoring requirements under this permit are effective on the first day of the second month following permit issuance. Until such time, the permittee shall continue to monitor and report in accordance with previously effective permit requirements, if any. During the period of operation authorized by this permit, the permittee shall complete and submit to the Department, at the address listed below, the Discharge Monitoring Reports (DMRs) in accordance with the frequencies specified by the REPORT type (i.e., monthly, toxicity, quarterly, semiannual, annual, etc.) indicated on the DMR forms attached to this permit. Monitoring results for each monitoring period shall be submitted in accordance with the associated DMR due dates below.

REPORT Type on DMR	Monitoring Period	DMR Due Date
Monthly or Toxicity	first day of month – last day of month	28^{th} day of following month
Quarterly	January 1 - March 31 April 1 – June 30 July 1 – September 30 October 1 – December 31	April 28 July 28 October 28 January 28
Semiannual	January 1 – June 30 July 1 – December 31	July 28 January 28
Annual	January 1 – December 31	January 28

DMRs shall be submitted for each required monitoring period including months of no discharge.

The permittee shall make copies of the attached DMR form(s) and shall submit the completed DMR form(s) to the Department at the address specified below:

Florida Department of Environmental Protection
Wastewater Compliance Evaluation Section, Mail Station 3551
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

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4. Unless specified otherwise in this permit, all reports and notifications required by this permit, including twenty-four hour notifications, shall be submitted to or reported to the Central District Office at the address specified below:

   Central District Office
   3319 Maguire Boulevard Suite 232
   Orlando, Florida 32803-3767

   Phone Number - (407) 894-7555
   FAX Number - (407) 897-2966
   All FAX copies shall be followed by original copies.

5. All reports and other information shall be signed in accordance with requirements of Rule 62-620.305, F.A.C.

6. The permittee shall provide safe access points for obtaining representative samples which are required by this permit.

7. If there is no discharge from the facility on a day scheduled for sampling, the sample shall be collected on the day of the next discharge.

8. Bypasses subject to General Conditions VIII.20. and VIII.22. shall be monitored or estimated daily, or as approved by the Department for flow and other parameters required for the specific outfall which is bypassed. Monitoring results shall be reported to the Department

9. The Permittee shall continue compliance with the facility's Manatee Protection Plan approved by the Department on December 21, 2000.

10. The Permittee shall develop a Plan of Study (POS), subject to Department review and approval, to monitor *compliance with Rule 62-302.520(1)*, F.A.C. pursuant to the schedule in Item VI.4, including a proposed implementation schedule, designed to determine any effects on biological communities from the discharge to Indian River Lagoon. The plan shall address monitoring of aquatic species as necessary, and shall include reporting requirements. The POS shall incorporate relevant existing data developed by the Permittee and other sources as well as any necessary additional monitoring to be conducted by the Permittee.

II. Industrial Sludge Management Requirements

A. Basic Management Requirements

1. Disposal of sludge in a solid waste management facility permitted by the Department shall be in accordance with the requirements of Chapter 62-701, F.A.C. Storage, transportation, and disposal of sludge/solids characterized as hazardous waste shall be in compliance with requirements of Chapter 62-730, F.A.C.

2. The permittee shall keep records of the amount of sludge or residuals disposed, transported, or incinerated. If a person other than the permittee is responsible for sludge transporting, disposal, or incineration, the permittee shall also keep the following records:

   a. name, address and telephone number of any transporter, and any manifests or bill of lading used;
   b. name and location of the site of disposal, treatment or incineration;
   c. name, address, and telephone number of the entity responsible for the disposal, treatment, or incineration site.

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III. Ground Water Monitoring Requirements

1. During the period of operation authorized by this permit, the permittee shall continue to sample ground water at the existing monitoring wells identified in Permit Condition III. 2. below, in accordance with this permit and the approved ground water monitoring plan prepared in accordance with Rule 62-522.600, F.A.C. Within 90 days of placing the new or modified wastewater facility into operation, or installation of new monitoring wells, whichever occurs sooner, the permittee shall begin sampling ground water at the new monitoring wells identified in Permit Condition III. 2 below in accordance with this permit and the approved ground water monitoring plan.

2. The following monitoring wells shall be sampled quarterly. Sampling must be reasonably spaced to be representative of potentially changing conditions:

Facility Well Name	Permit Well Name	Monitoring Location ID Number	WAFR Number	Depth (feet)	Aquifer Monitored	Well Type	New or Existing
All Sites							
CA-MW-1	MWB-2683	3005A15832	2683	21	Surficial	Background	Existing
Equipment Area Runoff Basin (B-3)							
CA-MW-2	MWC-2682	3005A15833	2682	21	Surficial	Compliance	Existing
E/P Basin Spray Area (SP-1)							
OB-2	MWC-2686	3005A11264	2686	25.6	Surficial	Compliance	Existing
Solids Settling Basins (B-1A and B-1B)							
OB-3	MWC-2685	3005A11265	2685	24.9	Surficial	Compliance	Existing
Evaporation/Percolation Basin (EP-1)							
OB-5	MWC-26897	--	26897	18	Surficial	Compliance	Existing

MWB = Background; MWC = Compliance

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3. The following parameters shall be analyzed quarterly in each of the monitoring wells identified in Item III. 2. except Monitoring Well OB-5:

Parameter Name	Standard Compliance Well Limit	Units
Chloride	Report[8]	mg/L
pH	Report[8]	SU
Sodium	Report[9]	mg/L
Specific Conductance	Report	Umhos
Sulfate	Report[8]	mg/L
Total Dissolved Solids (TDS)	Report[8]	mg/L
Total Recoverable Petroleum Hydrocarbons	5.0	mg/L
Turbidity	Report	NTU
Vinyl Chloride	1	ug/L
Water Level Relative to NGVD	Report	Feet, NGVD

[8] This facility has been in operation since 1977 and is an existing installation as defined in F.A.C. Rule 62-522.200(1) and is exempt from compliance with secondary standards for ground water at the edge of the zone of discharge in accordance with *F.A.C. Rules 62-520.520* and *62-522.300(6)*.
[9] The permittee is exempted from compliance with the Class G-II ground water standard for sodium in accordance with the Final Order Of Agency Action (sodium exemption) signed by the Secretary on October 12, 2004. This sodium exemption is effective for the duration of this permit.

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4. The following parameters shall be analyzed quarterly in Monitoring Well OB-5 identified in Item III: 2:

Parameter Name	Standard Compliance Well Limit	Units
Aluminum	Report[10]	ug/L
Antimony (added 2/04)	6	ug/L
Beryllium (added 2/04)	4	ug/L
Cadmium	5	ug/L
Chloride	Report[10]	mg/L
Chromium	100	ug/L
Copper	Report[10]	ug/L
Cyanide	200	ug/L
Fluoride	4,000	ug/L
Iron	Report[10]	ug/L
Manganese	Report[10]	ug/L
Mercury	2.0	ug/L
Nickel	100	ug/L
pH	Report[10]	SU
Silver	Report[10]	ug/L
Sodium	Report[11]	mg/L
Specific Conductance	Report	mmhos
Sulfate	Report[10]	mg/L
TDS	Report[10]	mg/L
Tetrachloroethylene	3	ug/L
Total Phenols	Report	ug/L
Trichloroethylene	3	ug/L
Total Recoverable Petroleum Hydrocarbons	5.0	mg/L
Turbidity	Report	NTU
Vinyl chloride	1	ug/L
Zinc	Report[10]	ug/L
Water Level (ft NGVD)	Report	Feet, NGVD

5. The zone of discharge extends to the facility property boundary, and vertically to the base of the shallow water table aquifer.

6. The permittee's discharge to ground water shall not cause a violation of water quality standards for ground waters at the boundary of the zone of discharge in accordance with Rules 62-520.400 and 62-520.420, F.A.C.

7. The permittee's discharge to ground water shall not cause a violation of the minimum criteria for ground water specified in Rule 62-520.400, F.A.C., within the zone of discharge.

[10] This facility has been in operation since 1977 and is an existing installation as defined in F.A.C. Rule 62-522.200(1) and is exempt from compliance with secondary standards for ground water at the edge of the zone of discharge in accordance with F.A.C. Rules 62-520.520 and 62-522.300(6).
[11] The permittee is exempted from compliance with the Class G-II ground water standard for sodium in accordance with the Final Order Of Agency Action (sodium exemption) signed by the Secretary on October 12, 2004. This sodium exemption is effective for the duration of this permit.

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8. If the concentration for any constituent listed in Permit Condition III.3 in the natural background quality of the ground water is greater than the stated maximum, or in the case of pH is also less than the minimum, the representative natural background quality shall be the prevailing standard.

9. Water levels shall be recorded prior to evacuating the well for sample collection. Elevation references shall include the top of the well casing and land surface at each well site (NGVD allowable) at a precision of plus or minus 0.1 feet.

10. Ground water monitoring wells shall be purged prior to sampling to obtain a representative sample.

11. Analyses shall be conducted on un-filtered samples, unless filtered samples have been approved by the Department as being more representative of ground water conditions.

12. If a monitoring well becomes damaged or cannot be sampled for some reason, the permittee shall notify the Department immediately and a written report shall follow within seven days detailing the circumstances and remedial measures taken or proposed. Repair or replacement of monitoring wells shall be approved in advance by the Department.

13. The permittee shall provide verbal notice to the Department as soon as practical after discovery of a sinkhole within an area for the management or application of wastewater or sludge. The permittee shall immediately implement measures appropriate to control the entry of contaminants, and shall detail these measures to the Department in a written report within 7 days of the sinkhole discovery.

14. Ground water monitoring test results shall be submitted on Part D of DEP Form 62-620.910(10) (attached) and shall be submitted to the Central District Ground Water Section. A completed Certification Page shall accompany each quarter of monitoring data. The quarterly ground water monitoring results shall be submitted with the DMR as shown in the following schedule:

SAMPLE PERIOD	REPORT DUE DATE
January - March	April 28
April - June	July 28
July - September	October 28
October - December	January 28

IV. Other Land Application Requirements

1. This section is not applicable to this facility.

V. Operation and Maintenance Requirements

A. Operation of Treatment and Disposal Facilities

1. The permittee shall ensure that the operation of this facility is as described in the application and supporting documents.

2. The operation of the pollution control facilities described in this permit shall be under the supervision of a person who is qualified by formal training and/or practical experience in the field of water pollution control.

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B. Record keeping Requirements:

1. The permittee shall maintain the following records on the site of the permitted facility and make them available for inspection:

   a. Records of all compliance monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, including, if applicable, a copy of the laboratory certification showing the certification number of the laboratory, for at least three years from the date the sample or measurement was taken;

   b. Copies of all reports, other than those required in items a. and f. of this section, required by the permit for at least three years from the date the report was prepared, unless otherwise specified by Department rule;

   c. Records of all data, including reports and documents used to complete the application for the permit for at least three years from the date the application was filed, *unless otherwise specified by Department rule;*

   d. A copy of the current permit;

   e. A copy of any required record drawings;

   f. Copies of the logs and schedules showing plant operations and equipment maintenance for three years from the date on the logs or schedule.

VI. Schedules

1. A Best Management Practices Pollution Prevention (BMP3) Plan shall be prepared and implemented in accordance with Part VII of this permit and the following schedule:

Action Item		Scheduled Completion Date
1	Continue Implementing Existing BMP3 Plan	Issuance Date of Permit

2. The permittee shall achieve compliance with the other conditions of this permit as follows:

   a. Opertional level attained .... Issuance Date of Permit

3. The following construction schedule shall be followed:

   a. Relocate Outfall D-030 to I-016 .... 6 months of Issuance Date of Permit

   b. Submit Certificate of Completion of Construction (See VII.B.1) .... 30 days of Completion of Construction

   c. Submit Record Drawings (See VII.B.2)...6 months after Completion of Construction

4. Biological Monitoring Program:

   a. Within six months of issuance of this permit, the Permittee shall meet with the Department to discuss the content of a Plan of Study (POS) for biological monitoring in accordance with the requirements of Item

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I.E.10, and shall submit the POS within twelve months of issuance of this permit. The Department will review the POS and provide written comments to the permittee as needed. The permittee shall implement the POS in accordance with the approved implementation shedule.

5. Additional Intake/Discharge Sampling and Reporting

   a. Within 60 days of permit issuance the permittee shall begin additional sampling to be conducted quarterly for a total of 4 sampling events. Concurrent 24-hour composite samples shall be taken of the intake and from Outfalls D-011, D-012, and D-015 (Sample Points EFF-1, EFF-2, and EFF-3) and analyzed for Copper, Nickel, and Beryllium.

   b. Sampling results shall be submitted to the Department with the next scheduled quarterly report and include results from the sampling events since the last submittal except results submitted for the fourth quarterly report shall include summary results from all 4 sampling events.

   c. Analytical test methods, method detection limits (MDLs), and practical quantification limits (PQLs) shall be in accordance with the requirements of Section I.E.1 of this permit.

   d. If the sampling results indicate a reasonable potential for an exceedance of water quality standards and concentrations in the discharge exceed intake concentrations, taking into account sampling and analytical variations, then the Department may reopen the permit in accordance with Section VII.F.2 of this permit to include different limitations or monitoring requirements or take other action as appropriate.

6. The Permittee shall comply with the requirements of 40 CFR Part 125.95(a)(1) and (2) no later than upon submittal of a timely application for permit renewal, submitted pursuant to the requirements of Condition VII.C. of this permit.

7. No later than 14 calendar days following a date identified in the above schedule(s) of compliance, the permittee shall submit either a report of progress or, in the case of specific actions being required by an identified date, a written notice of compliance or noncompliance. In the latter case, the notice shall include the cause of noncompliance, any remedial actions taken, and the probability of meeting the next scheduled requirement.

VII. Other Specific Conditions

A. Specific Conditions Applicable to All Permits

1. Drawings, plans, documents or specifications submitted by the permittee, not attached hereto, but retained on file at the Northwest District Office, are made a part hereof.

2. Where required by Chapter 471 (P.E.) or Chapter 492 (P.G.) Florida Statutes, applicable portions of reports to be submitted under this permit, shall be signed and sealed by the professional(s) who prepared them.

3. This permit satisfies Industrial Wastewater program permitting requirements only and does not authorize operation of this facility prior to obtaining any other permits required by local, state or federal agencies.

B. Specific Conditions Related to Construction

1. Within thirty days of completion of construction, the permittee shall submit to the Department a completed "Certificate of Completion of Construction" (DEP Form 62-620.910(12) signed and sealed by the engineer of record or other engineer registered in the State of Florida.

2. Record drawings shall be prepared and made available in accordance with Rule 62-620.410(6), F.A.C, and the Department of Environmental Protection Guide to wastewater Permitting within six months of placing the facility into operation.

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C. Duty to Reapply

1. The permittee shall submit an application to renew this permit at least 180 days before the expiration date of this permit.

2. The permittee shall apply for renewal of this permit on the appropriate form listed in Rule 62-620.910, F.A.C., and in the manner established in Chapter 62-620, F.A.C., and the Department of Environmental Protection Guide to Wastewater Permitting including submittal of the appropriate processing fee set forth in Rule 62-4.050, F.A.C.

3. An application filed in accordance with subsections 1. and 2. of this part shall be considered timely and sufficient. When an application for renewal of a permit is timely and sufficient, the existing permit shall not expire until the Department has taken final action on the application for renewal or until the last day for seeking judicial review of the agency order or a later date fixed by order of the reviewing court.

4. The late submittal of a renewal application shall be considered timely and sufficient for the purpose of extending the effectiveness of the expiring permit only if it is submitted and made complete before the expiration date.

D. Specific Conditions Related to Best Management Practices/Pollution Prevention Conditions

1. **General Conditions**

In accordance with Section 304(e) and 402(a)(2) of the Clean Water Act (CWA) as amended, 33 U.S.C. §§ 1251 et seq., and the Pollution Prevention Act of 1990, 42 U.S.C. §§ 13101-13109, the permittee must develop and implement a plan for utilizing practices incorporating pollution prevention measures. References to be considered in developing the plan are "Criteria and Standards for Best Management Practices Authorized Under Section 304(e) of the Act," found at 40 CFR 122.44 Subpart K and the Waste Minimization Opportunity Assessment Manual, EPA/625/7-88/003.

a. Definitions

(1) The term "pollutants" refers to conventional, non-conventional and toxic pollutants.

(2) Conventional pollutants are: biochemical oxygen demand (BOD), suspended solids, pH, fecal coliform bacteria and oil & grease.

(3) Non-conventional pollutants are those which are not defined as conventional or toxic.

(4) Toxic pollutants include, but are not limited to: (a) any toxic substance listed in Section 307(a)(1) of the CWA, any hazardous substance listed in Section 311 of the CWA, or chemical listed in Section 313(c) of the Superfund Amendments and Reauthorization Act of 1986; and (b) any substance (that is not also a conventional or non-conventional pollutant except ammonia) for which EPA has published an acute or chronic toxicity criterion.

(5) "Pollution prevention" and "waste minimization" refer to the first two categories of EPA's preferred hazardous waste management strategy: first, source reduction and then, recycling.

(6) "Recycle/Reuse" is defined as the minimization of waste generation by recovering and reprocessing usable products that might otherwise become waste; or the reuse or reprocessing of usable waste products in place of the original stock, or for other purposes such as material recovery, material regeneration or energy production.

(7) "Source reduction" means any practice which: (a) reduces the amount of any pollutant entering a waste stream or otherwise released into the environment (including fugitive emissions) prior to recycling, treatment or disposal; and (b) reduces the hazards to public health and the environment associated with the release of such pollutant. The term includes equipment or technology modifications, process or procedure modifications, reformulation or redesign of products, substitution of raw materials, and improvements in housekeeping, maintenance, training, or inventory control. It does not include any practice which alters the physical, chemical, or biological characteristics or the volume of a pollutant through a process or activity which itself is not integral to, or previously considered necessary for, the production of a product or the providing of a service.

(8) "BMP3" means a Best Management Plan incorporating the requirements of 40 CFR § 122.44, Subpart K, plus pollution prevention techniques associated with a Waste Minimization Assessment.

(9) "Waste Minimization Assessment" means a systematic planned procedure with the objective of identifying ways to reduce or eliminate waste.

2. <u>Best Management Practices/Pollution Prevention Plan</u>

The permittee shall develop and implement a BMP3 plan for the facility which is the source of wastewater and storm water discharges covered by this permit. The plan shall be directed toward reducing those pollutants of concern which discharge to surface waters and shall be prepared in accordance with good engineering and good housekeeping practices. For the purposes of this permit, pollutants of concern shall be limited to toxic pollutants, as defined above, known to the discharger. The plan shall address all activities which could or do contribute these pollutants to the surface water discharge, including process, treatment, and ancillary activities. The BMP3 plan shall contain the following components:

a. Signatory Authority & Management Responsibilities

The BMP3 plan shall be signed by the permittee or their duly authorized representative in accordance with rule 62-620.305(2)(a) and (b). The BMP3 plan shall be reviewed by the plant environmental/engineering staff and plant manager. Where required by Chapter 471 (P.E.) or Chapter 492 (P.G.) Florida Statutes, applicable portions of the BMP3 plan shall be signed and sealed by the professional(s) who prepared them.

A copy of the plan shall be retained at the facility and shall be made available to the Department upon request.

The BMP3 plan shall contain a written statement from corporate or plant management indicating management's commitment to the goals of the BMP3 program. Such statements shall be publicized or made known to all facility employees. Management shall also provide training for the individuals responsible for implementing the BMP3 plan.

b. BMP3 Plan Requirements

(1) Name & description of facility, a map illustrating the location of the facility & adjacent receiving waters, and other maps, plot plans or drawings, as necessary;

(2) Overall objectives (both short-term and long-term) and scope of the plan, specific reduction goals for pollutants, anticipated dates of achievement of reduction, and a description of means for achieving each reduction goal;

(3) A description of procedures relative to spill prevention, control & countermeasures and a description of measures employed to prevent storm water contamination;

(4) A description of practices involving preventive maintenance, housekeeping, recordkeeping, inspections, and plant security; and

c. Waste Minimization Assessment

The permittee is encouraged but not required to conduct a waste minimization assessment (WMA) for this facility to determine actions that could be taken to reduce waste loadings and chemical losses to all wastewater and/or storm water streams as described in Part VII.D.3 of this permit.

If the Permittee elects to develop and implement a WMA, information on plan components can be obtained from the Department's Industrial Wastewater website, or from:

Florida Department of Environmental Protection
Industrial Wastewater Section, Mail Station 3545
Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

(850) 245-8589
(850) 245-8669 -- Fax

d. Best Management Practices & Pollution Prevention Committee Recommended:

A Best Management Practices Committee (Committee) should be established to direct or assist in the implementation of the BMP3 plan. The Committee should be comprised of individuals within the plant organization who are responsible for developing the BMP3 plan and assisting the plant manager in its implementation, monitoring of success, and revision. The activities and responsibilities of the Committee should address all aspects of the facility's BMP3 plan. The scope of responsibilities of the Committee should be described in the plan.

e. Employee Training

Employee training programs shall inform personnel at all levels of responsibility of the components & goals of the BMP3 plan and shall describe employee responsibilities for implementing the plan. Training shall address topics such as good housekeeping, materials management, record keeping & reporting, spill prevention & response, as well as specific waste reduction practices to be employed. Training shall also disclose how individual employees may contribute suggestions concerning the BMP3 plan or suggestions regarding Pollution Prevention. The plan shall identify periodic dates for such training.

f. Plan Development & Implementation

The BMP3 plan shall be implemented upon the effective date of this permit, unless any later dates are specified in this permit. If a WMA is ongoing at the time of development or implementation it may be described in the plan. Any waste reduction practice which is recommended for implementation over a period of time may also be identified in the plan, including a schedule for its implementation.

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g. Submission of Plan Summary & Progress/Update Reports

(1) Plan Summary: Not later than 2 years after the effective date of the permit, a summary of the BMP3 plan shall be developed and maintained at the facility and made available to the Department upon request. The summary shall include the following: a brief description of the plan, its implementation process, schedules for implementing identified waste reduction practices, and a list of all waste reduction practices being employed at the facility. The results of WMA studies, as well as scheduled WMA activities may be discussed.

(2) Progress/Update Reports: Annually thereafter for the duration of the permit progress/update reports documenting implementation of the plan shall be maintained at the facility and made available to the Department upon request. The reports shall discuss whether or not implementation schedules were met and revise any schedules, as necessary. The plan shall also be updated as necessary and the attainment or progress made toward specific pollutant reduction targets documented. Results of any ongoing WMA studies as well as any additional schedules for implementation of waste reduction practices may be included.

(3) A recommended timetable for the various plan requirements follows:

Timetable for BMP3 Plan:

ELEMENT	TIME FROM EFFECTIVE DATE OF THIS PERMIT
Complete WMA (if appropriate)	6 months
Progress/Update Reports	3 years, and then annually thereafter

The permittee shall maintain the plan and subsequent reports at the facility and shall make the plan available to the Department upon request.

h. Plan Review & Modification

If following review by the Department, the BMP3 plan is determined insufficient, the permittee will be notified that the BMP3 plan does not meet one or more of the minimum requirements of this Part. Upon such notification from the Department, the permittee shall amend the plan and shall submit to the Department a written certification that the requested changes have been made. Unless otherwise provided by the Department, the permittee shall have 30 days after such notification to make the changes necessary.

The permittee shall modify the BMP3 plan whenever there is a change in design, construction, operation, or maintenance, which has a significant effect on the potential for the discharge of pollutants to waters of the State or if the plan proves to be ineffective in achieving the general objectives of reducing pollutants in wastewater or storm water discharges. Modifications to the plan may be reviewed by the Department in the same manner as described above.

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E. Specific Conditions Related to Existing Manufacturing, Commercial, Mining, and Silviculture Wastewater Facilities or Activities

1. Existing manufacturing, commercial, mining, and silvicultural wastewater facilities or activities that discharge into surface waters shall notify the Department as soon as they know or have reason to believe:

   a. That any activity has occurred or will occur which would result in the discharge, on a routine or frequent basis, of any toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following levels
      (1) One hundred micrograms per liter,
      (2) Two hundred micrograms per liter for acrolein and acrylonitrile; five hundred micrograms per liter for 2,4-dinitrophenol and for 2-methyl-4,6-dinitrophenol; and one milligram per liter for antimony, or
      (3) Five times the maximum concentration value reported for that pollutant in the permit application.

   b. That any activity has occurred or will occur which would result in any discharge, on a non-routine or infrequent basis, of a toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following levels
      (1) Five hundred micrograms per liter,
      (2) One milligram per liter for antimony, or
      (3) Ten times the maximum concentration value reported for that pollutant in the permit application.

F. Reopener Clause

1. The permit shall be revised, or alternatively, revoked and reissued in accordance with the provisions contained in Rules 62-620.325 and 62-620.345 F.A.C., if applicable, or to comply with any applicable effluent standard or limitation issued or approved under Sections 301(b)(2)(C) and (D), 304(b)(2) and 307(a)(2) of the Clean Water Act (the Act), as amended, if the effluent standards, limitations, or water quality standards so issued or approved:

   a. Contains different conditions or is otherwise more stringent than any condition in the permit/or;

   b. Controls any pollutant not addressed in the permit.

   The permit as revised or reissued under this paragraph shall contain any other requirements then applicable.

2. The permit may be reopened to adjust effluent limitations or monitoring requirements should future Water Quality Based Effluent Limitation determinations, water quality studies, DEP approved changes in water quality standards, or other information show a need for a different limitation or monitoring requirement.

3. The Department may develop a Total Maximum Daily Load (TMDL) during the life of the permit. Once a TMDL has been established and adopted by rule, the Department shall revise this permit to incorporate the final findings of the TMDL.

VIII. General Conditions

1. The terms, conditions, requirements, limitations and restrictions set forth in this permit are binding and enforceable pursuant to Chapter 403, F.S. Any permit noncompliance constitutes a violation of Chapter 403, F.S., and is grounds for enforcement action, permit termination, permit revocation and reissuance, or permit revision. *[62-620.610(1), F.A.C.]*

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2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications or conditions of this permit constitutes grounds for revocation and enforcement action by the Department. *[62-620.610(2), F.A.C.]*

3. As provided in Subsection 403.087(6), F.S., the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor authorize any infringements of federal, state, or local laws or regulations. This permit is not a waiver of or approval of any other Department permit or authorization that may be required for other aspects of the total project which are not addressed in this permit. *[62-620.610(3), F.A.C.]*

4. This permit conveys no title to land or water, does not constitute state recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title. *[62-620.610(4), F.A.C.]*

5. This permit does not relieve the permittee from liability and penalties for harm or injury to human health or welfare, animal or plant life, or property caused by the construction or operation of this permitted source; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department. The permittee shall take all reasonable steps to minimize or prevent any discharge, reuse of reclaimed water, or residuals use or disposal in violation of this permit which has a reasonable likelihood of adversely affecting human health or the environment. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. *[62-620.610(5), F.A.C.]*

6. If the permittee wishes to continue an activity regulated by this permit after its expiration date, the permittee shall apply for and obtain a new permit. *[62-620.610(6), F.A.C.]*

7. The permittee shall at all times properly operate and maintain the facility and systems of treatment and control, and related appurtenances, that are installed and used by the permittee to achieve compliance with the conditions of this permit. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to maintain or achieve compliance with the conditions of the permit. *[62-620.610(7), F.A.C.]*

8. This permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit revision, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance does not stay any permit condition. *[62-620.610(8), F.A.C.]*

9. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, including an authorized representative of the Department and authorized EPA personnel, when applicable, upon presentation of credentials or other documents as may be required by law, and at reasonable times, depending upon the nature of the concern being investigated, to
   a. Enter upon the permittee's premises where a regulated facility, system, or activity is located or conducted, or where records shall be kept under the conditions of this permit;
   b. Have access to and copy any records that shall be kept under the conditions of this permit;
   c. Inspect the facilities, equipment, practices, or operations regulated or required under this permit; and
   d. Sample or monitor any substances or parameters at any location necessary to assure compliance with this permit or Department rules.

   [62-620.610(9), F.A.C.]

10. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data, and other information relating to the construction or operation of this permitted source which are submitted to the

Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except as such use is proscribed by Section 403.111, Florida Statutes, or Rule 62-620.302, F.A.C. Such evidence shall only be used to the extent that it is consistent with the Florida Rules of Civil Procedure and applicable evidentiary rules. *[62-620.610(10), F.A.C.]*

11. When requested by the Department, the permittee shall within a reasonable time provide any information required by law which is needed to determine whether there is cause for revising, revoking and reissuing, or terminating this permit, or to determine compliance with the permit. The permittee shall also provide to the Department upon request copies of records required by this permit to be kept. If the permittee becomes aware of relevant facts that were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be promptly submitted or corrections promptly reported to the Department. *[62-620.610(11), F.A.C.]*

12. Unless specifically stated otherwise in Department rules, the permittee, in accepting this permit, agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance; provided however, the permittee does not waive any other rights granted by Florida Statutes or Department rules. A reasonable time for compliance with a new or amended surface water quality standard, other than those standards addressed in Rule 62-302.500, F.A.C., shall include a reasonable time to obtain or be denied a mixing zone for the new or amended standard. *[62-620.610(12), F.A.C.]*

13. The permittee, in accepting this permit, agrees to pay the applicable regulatory program and surveillance fee in accordance with Rule 62-4.052, F.A.C. *[62-620.610(13), F.A.C.]*

14. This permit is transferable only upon Department approval in accordance with Rule 62-620.340, F.A.C. The permittee shall be liable for any noncompliance of the permitted activity until the Department approves the transfer. *[62-620.610(14), F.A.C.]*

15. The permittee shall give the Department written notice at least 60 days before inactivation or abandonment of a wastewater facility and shall specify what steps will be taken to safeguard public health and safety during and following inactivation or abandonment. *[62-620.610(15), F.A.C.]*

16. The permittee shall apply for a revision to the Department permit in accordance with Rule 62-620.300, F.A.C., and the Department of Environmental Protection Guide to Wastewater Permitting at least 90 days before construction of any planned substantial modifications to the permitted facility is to commence or with Rule 62-620.325(2), F.A.C., for minor modifications to the permitted facility. A revised permit shall be obtained before construction begins except as provided in Rule 62-620.300, F.A.C. *[62-620.610(16), F.A.C.]*

17. The permittee shall give advance notice to the Department of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements. The permittee shall be responsible for any and all damages which may result from the changes and may be subject to enforcement action by the Department for penalties or revocation of this permit. The notice shall include the following information:
    a. A description of the anticipated noncompliance;
    b. The period of the anticipated noncompliance, including dates and times; and
    c. Steps being taken to prevent future occurrence of the noncompliance.
    [62-620.610(17), F.A.C.]

18. Sampling and monitoring data shall be collected and analyzed in accordance with Rule 62-4.246, Chapters 62-160 and 62-601, F.A.C., and 40 CFR 136, as appropriate.
    a. Monitoring results shall be reported at the intervals specified elsewhere in this permit and shall be reported on a Discharge Monitoring Report (DMR), DEP Form 62-620.910(10).

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b. If the permittee monitors any contaminate more frequently than required by the permit, using Department approved test procedures, the results of this monitoring shall be included in the calculation and reporting of the data submitted in the DMR.

c. Calculations for all limitations which require averaging of measurements shall use an arithmetic mean unless otherwise specified in this permit.

d. Any laboratory test required by this permit shall be performed by a laboratory that has been certified by the Department of Health (DOH) under Chapter 64B-1, F.A.C., where such certification is required by Rule 62-160.300(4), F.A.C. The laboratory must be certified for any specific method and analyte combination that is used to comply with this permit. For domestic wastewater facilities, the on-site test procedures specified in Rule 62-160.300(4), F.A.C., shall be performed by a laboratory certified test for those parameters or under the direction of an operator certified under Chapter 62-602, F.A.C.

e. Fields activities including on-site tests and sample collection, whether performed by a laboratory or a certified operator, must follow the applicable procedures described in DEP-SOP-001/01 (January 2002). Alternate field procedures and laboratory methods may be used where they have been approved according to the requirements of Rules 62-160.220, 62-160.330, and 62-160.600, F.A.C.
[62-620.610(18), F.A.C.]

19. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule detailed elsewhere in this permit shall be submitted no later than 14 days following each schedule date. *[62-620.610(19), F.A.C.]*

20. The permittee shall report to the Department's Central District Office any noncompliance which may endanger health or the environment. Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided within five days of the time the permittee becomes aware of the circumstances. The written submission shall contain: a description of the noncompliance and its cause; the period of noncompliance including exact dates and time, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

a. The following shall be included as information which must be reported within 24 hours under this condition:
(1) Any unanticipated bypass which causes any reclaimed water or effluent to exceed any permit limitation or results in an unpermitted discharge,
(2) Any upset which causes any reclaimed water or the effluent to exceed any limitation in the permit,
(3) Violation of a maximum daily discharge limitation for any of the pollutants specifically listed in the permit for such notice, and
(4) Any unauthorized discharge to surface or ground waters.

b. Oral reports as required by this subsection shall be provided as follows:
(1) For unauthorized releases or spills of untreated or treated wastewater reported pursuant to subparagraph a.4 that are in excess of 1,000 gallons per incident, or where information indicates that public health or the environment will be endangered, oral reports shall be provided to the Department by calling the STATE WARNING POINT TOLL FREE NUMBER (800) 320-0519, as soon as practical, but no later than 24 hours from the time the permittee becomes aware of the discharge. The permittee, to the extent known, shall provide the following information to the State Warning Point:
(a) Name, address, and telephone number of person reporting;
(b) Name, address, and telephone number of permittee or responsible person for the discharge;
(c) Date and time of the discharge and status of discharge (ongoing or ceased);
(d) Characteristics of the wastewater spilled or released (untreated or treated, industrial or domestic wastewater);
(e) Estimated amount of the discharge;
(f) Location or address of the discharge;
(g) Source and cause of the discharge;
(h) Whether the discharge was contained on-site, and cleanup actions taken to date;

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(i) Description of area affected by the discharge, including name of water body affected, if any; and
(j) Other persons or agencies contacted.

(2) Oral reports, not otherwise required to be provided pursuant to subparagraph b(1) above, shall be provided to Department's Central District Office within 24 hours from the time the permittee becomes aware of the circumstances.

c. If the oral report has been received within 24 hours, the noncompliance has been corrected, and the noncompliance did not endanger health or the environment, the Department's Central District Office shall waive the written report.
[62-620.610(20), F.A.C.]

21. The permittee shall report all instances of noncompliance not reported under Conditions VIII. 18 and 19 of this permit at the time monitoring reports are submitted. This report shall contain the same information required by Condition VIII. 20. of this permit. *[62-620.610(21), F.A.C.]*

22. Bypass Provisions.

a. Bypass is prohibited, and the Department may take enforcement action against a permittee for bypass, unless the permittee affirmatively demonstrates that:
   (1) Bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and
   (2) There were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if adequate back-up equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass which occurred during normal periods of equipment downtime or preventative maintenance; and
   (3) The permittee submitted notices as required under Condition VIII.22.b. of this permit.

b. If the permittee knows in advance of the need for a bypass, it shall submit prior notice to the Department, if possible at least 10 days before the date of the bypass. The permittee shall submit notice of an unanticipated bypass within 24 hours of learning about the bypass as required in Condition VIII.20. of this permit. A notice shall include a description of the bypass and its cause; the period of the bypass, including exact dates and times; if the bypass has not been corrected, the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence of the bypass.

c. The Department shall approve an anticipated bypass, after considering its adverse effect, if the permittee demonstrates that it will meet the three conditions listed in Condition VIII.22 a. (1) through (3) of this permit.

d. A permittee may allow any bypass to occur which does not cause reclaimed water or effluent limitations to be exceeded if it is for essential maintenance to assure efficient operation. These bypasses are not subject to the provision of Condition VIII.22.a. through c. of this permit.
[62-620.610(22), F.A.C.]

23. Upset Provisions

a. A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed contemporaneous operating logs, or other relevant evidence that:
   (1) An upset occurred and that the permittee can identify the cause(s) of the upset;
   (2) The permitted facility was at the time being properly operated;
   (3) The permittee submitted notice of the upset as required in Condition VIII.20. of this permit; and
   (4) The permittee complied with any remedial measures required under Condition VIII.5. of this permit.

b. In any enforcement proceeding, the permittee seeking to establish the occurrence of an upset has the burden of proof.

c. Before an enforcement proceeding is instituted, no representation made during the Department review of a claim that noncompliance was caused by an upset is final agency action subject to judicial review.
[62-620.610(23), F.A.C.]

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Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT OF
ENVIRONMENTAL PROTECTION

Mimi A. Drew
Director, Division of Water Resource Management

2600 Blair Stone Road
Tallahassee, FL 32399-2400
(850) 245-8336

Department of Environmental Protection

Jeb Bush
Governor

Twin Towers Office Building
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

David B. Struhs
Secretary

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

In the matter of:
Approval of FPL Cape Canaveral Power Plant
Manatee Protection Plan

DEP Permit No. FL0001473
Brevard County

Mr. Ron Hix
FPL-5ES/JB
Florida Power & Light Company (FPL)
P. O. Box 14000
Juno Beach, FL 33408

NOTICE OF AGENCY ACTION

The Department of Environmental Protection hereby gives notice of its approval of the enclosed Manatee Protection Plan for the FPL Cape Canaveral Plant, dated August 8, 2000. The Manatee Protection Plan was completed pursuant to Specific Condition 13 of the above referenced permit.

A person whose substantial interests are affected by the Department action may petition for an administrative hearing in accordance with sections 120.569 and 120.57 of the Florida Statutes.

The petition must contain the information set forth below and must be filed (received) in the Department of Environmental Protection, Office of General Counsel, Mail Station 35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000. Petitions filed by the applicant or any of the parties listed below must be filed within twenty-one days of receipt of this notice of intent. Petitions filed by any other person must be filed within twenty-one days of publication of the public notice or within twenty-one days of receipt of this notice of intent, whichever occurs first. A petitioner must mail a copy of the petition to the applicant at the address indicated above, at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under sections 120.569 and 120.57 of the Florida Statutes, or to intervene in this proceeding and participate as a party to it. Any subsequent intervention will be only at the discretion of the presiding officer upon the filing of a motion in compliance with rule 28-5.207 of the Florida Administrative Code.

A petition must contain the following information:
(a) The name, address, and telephone number of each petitioner; the Department case 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 Department action;
(c) A statement of how each petitioner's substantial interests are affected by the Department action;
(d) A statement of the material facts disputed by the petitioner, if any;
(e) A statement of facts that the petitioner contends warrant reversal or modification of the Department action;
(f) A statement of which rules or statutes the petitioner contends require reversal or modification of the Department action; and
(g) A statement of the relief sought by the petitioner, stating precisely the action that the petitioner wants the Department to take.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department final action may be different from the position taken by it in this order. Persons whose substantial interests will be affected by any such final decision of the Department on the application have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation under section 120.573 of the Florida Statutes is not available for this proceeding.

This action is final and effective on the date filed with the Clerk of the Department unless a petition is filed in accordance with the above. Upon the timely filing of a petition this order will not be effective until further order of the Department.

Any party to the order has the right to seek judicial review of the order under section 120.68 of the Florida Statutes, by the filing of a notice of appeal under rule 9.110 of the Florida Rules of Appellate Procedure with the Clerk of the Department of Environmental Protection, Office of General Counsel, Mail Station 35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000; and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate district court of appeal. The notice of appeal must be filed within 30 days from the date when the final order is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Mimi Drew

Mimi Drew
Director
Division of Water Resource Management

2600 Blair Stone Road
Tallahassee, FL 32399-2400
(850) 487-1855

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF AGENCY ACTION and all copies were mailed before the close of business on 12-21-00 to the listed persons.

FILING AND ACKNOWLEDGMENT

FILED, on this date, under section 120.52(7), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

S. Shields 12-21-00
(Clerk) (Date)

Copies furnished to:

Kipp Frohlich, FWC Tallahassee
Chairman, Board of Brevard County Commissioners
Jim Valade, U.S. Fish and Wildlife Service
Save the Manatee Club
Christianne Ferraro, DEP Orlando
Betsy Hewitt, DEP Office of General Counsel

Florida Power & Light - Cape Canaveral Plant
Manatee Protection Plan
(August 8, 2000)

Purpose:

The purpose of the Cape Canaveral Plant Manatee Protection Plan is to set forth Florida Power & Light Company's (FPL) procedures to comply with Specific Condition 13 of the facility's State Industrial Wastewater Permit Number FL0001473 that was issued on February 24, 1999. This Specific Condition reads, in part:

13. The permittee, in so far as required to comply with Tasks 25 and 251 of the U.S. Fish and Wildlife Service (USFWS) "Florida Manatee Recovery Plan," shall develop a plan and procedures addressing potential manatee impacts, ...All plans, if required, shall include an implementation schedule and address, at a minimum:

    (a) Plans to minimize disruption to warm-water outflows during the winter and response procedures in case of disruptions.

    (b) Strategy to maintain discharge temperatures that will sustain manatees during cold events.

    (c) Plan to monitor ambient and discharge temperatures.

    (d) Precautions to minimize hazards to manatees at intake and outfall areas.

    (e) Timely communication to manatee recovery program personnel of any long term changes in the availability of warm water.

Compliance with Specific Condition 13:

1. This Manatee Protection Plan will be in effect during the term of the permit. In order for the plant's warm water discharge to provide a safe, warm water refuge for the manatees and to comply with Specific Condition 13, FPL will take the following actions:

    a) In the case of an unplanned shutdown or a plant failure occurring that will affect the warm water refuge from November 15 through March 31, when the ambient water temperature is below 61°F., the Florida Fish and Wildlife Conservation Commission (FWCC) and USFWS will be notified no later than four (4) hours after the event has occurred. If an unplanned shutdown occurs that is expected to result in no thermal discharge for 24 hours or longer, regardless of ambient water temperature, the Florida Marine Research Institute should be notified.

The following agency representatives shall be notified in the above referenced event or if any distressed manatees are observed at any time:

FWCC - Florida Marine Research Institute - Marine Mammal Pathobiology Lab: (727)-893-2904

USFWS - Jacksonville Field Office: (904) 232-2580

The FWCC, Bureau of Protected Species Management (BPSM) shall be provided a schedule of any anticipated in-water work within the discharge area or work that will affect the warm water refuge during the period of November 15 through March 31 each year. No routine in-water maintenance work shall occur in the discharge area from November 15 through March 31, unless it is considered essential by FPL and approved by BPSM prior to the start of work. If emergency in-water work is needed, the BPSM will be notified and consulted no later than two weeks following the commencement of the activity. All vessels used in the operation or associated with the activity shall be operated pursuant to the attached standard manatee construction conditions.

b) From November 15 through March 31 each year, to coincide with the time of greatest manatee abundance, if the ambient water temperature falls below 61°F., as measured at the plant intake, the FPL Cape Canaveral plant shall endeavor to operate in a manner that maintains the water temperature in an adequate portion of the discharge area, for at least one unit, at or above 68°F., until such time as the intake water temperature reaches 61°F., unless otherwise authorized by BPSM and the USFWS, or unless safety or reliability of the plant would be compromised.

c) The FPL Cape Canaveral power plant will provide personnel from the BPSM, USFWS, Florida Marine Research Institute, USGS-Sirenia Project, or a designee of these agencies, access to the FPL Cape Canaveral power plant property to conduct manatee research or monitoring activities which may include, placing, maintaining and downloading data from temperature data loggers. (These temperature data loggers will be used to collect air and water temperature data in an ongoing research effort to better understand manatee behavior patterns in response to artificial warm water refugia and environmental variables. The temperature data loggers will be placed in the discharge area and at ambient water and air locations). Access would be limited to normal business hours (8:00am - 5:00pm) unless arrangements are made in advance with the FPL Cape Canaveral power plant.

d) Intake Area: No special surveys will be required for the intake area.

Discharge Area: No special surveys will be required for the discharge area.

e) Should FPL decide to retire these units, notice will be provided to FWCC and USFWS as soon as practical after a definite decision is made or, if possible, at least five years prior to the date of retirement.

f) To assist in documenting long-term use patterns of this facility, FPL should conduct periodic aerial surveys of manatees at the Cape Canaveral facility. The continuation of the ongoing statewide aerial survey that FPL has funded in the past years meets these criteria.

g) The FPL Cape Canaveral Power Plant will provide phone numbers for weekday and weekend notification of appropriate plant personnel for the purpose of allowing FWCC or USFWS to coordinate manatee rescue operations as necessary.

2.) FPL actions, pursuant to this plan, that are conducted on a one-time basis unless there are significant physical or operational changes to the FPL Cape Canaveral power plant.

a) Provide a site map of the facility as a part of the plan that includes the following information;

1. The location of the intake pipes and discharge pipes.
2. Proximate streams, rivers, bays, etc.
3. The location of the condenser inlet and outlet temperature monitoring devices.
4. The location of any fuel barge docking facilities in relation to the discharge area.
5. The delineation of the no-entry boundary at the discharge area.

b) In order to evaluate and determine what portions of the thermal discharge will provide a sufficient warm water refuge for manatees under potential cold stress water conditions; the FPL Cape Canaveral power plant will, within two (2) years of the effective date of this plan, provide a profile of the thermal gradient (either actual or calculated) of the discharge area waters, as well as its gross bathymetry, at the mean rate of discharge when the ambient water temperature reaches a seasonal low.

Note: The "Thermal Analysis" conducted by FPL in January, 1996 and submitted to the FWCC meets the first requirement above ("... provide a profile of the thermal gradient (either actual or calculated) of the discharge area waters...").

FLORIDA POWER & LIGHT – CAPE CANAVERAL POWER PLANT MANATEE PROTECTION PLAN

1a) STANDARD MANATEE CONSTRUCTION CONDITIONS FOR ARTIFICIAL WARM WATER REFUGIA DURING THE PERIOD OF NOVEMBER 15 THROUGH MARCH 31.

The permittee shall comply with the following manatee protection conditions:

a. The permittee shall instruct all personnel associated with in-water work within the discharge canal and/or the warm water refuge of the potential presence of manatees and the need to avoid collisions with manatees. All vessels used in the operation or in association with the in-water work shall have an observer on board responsible for identifying the presence and location of manatee(s).

b. The permittee shall advise all construction personnel that there are civil and criminal penalties for harming, harassing, or killing manatees which are protected under the Marine Mammal Protection Act of 1972, The Endangered Species Act of 1973, and the Florida Manatee Sanctuary Act.

c. All vessels associated with in-water work associated with the discharge canal and/or warm water refuge shall operate at "no wake/idle" speeds at all times while in the manatee warm water refuge area. All vessels will follow routes of deep water whenever possible.

d. If manatee(s) are seen within the discharge canal and/or warm water refuge area all appropriate precautions shall be implemented to ensure protection of the manatee(s). These precautions shall include the immediate shutdown of equipment if necessary. Activities will not resume until the manatee(s) has departed to a safe distance on its own volition.

e. Any collision with and/or injury to a manatee shall be reported immediately to the Florida Wildlife Conservation Commission at 1-888-404-FWCC (1-888-404-3922). Collision and/or injury should also be reported to the U.S. Fish and Wildlife Service in Jacksonville (1-904-232-2580).

United States Department of the Interior

FISH AND WILDLIFE SERVICE
6620 Southpoint Drive, South
Suite 310
Jacksonville, Florida 32216-0912

IN REPLY REFER TO:

June 24, 2008

Randall LaBauve, Director
Environmental Services
Florida Power and Light Company
700 Universe Boulevard
Juno Beach, Florida 33408

Dear Mr LaBauve:

The U. S. Fish and Wildlife Service (Service) appreciates Florida Power and Light Company's (FP&L) efforts to notify us, the Florida Fish and Wildlife Conservation Commission (FWC), and others about plans to repower the Canaveral and Riviera Beach power plants and company concerns regarding manatees known to use these sites.

Repowering efforts will involve closing the plants for extended periods of time during demolition and construction activities, a process that will ultimately extend the plant's operational lifespan, as well as the associated warm water discharges. The shutdowns will include temporarily eliminating the warm water discharges from each site during the winter when they are typically used by hundreds of manatees.

At present, there are no authorizations in place under either the Marine Mammal Protection Act of 1972 or the Endangered Species Act of 1973 for the incidental take of manatees and their critical habitat. Wintering habitat is the most important biological factor limiting manatee populations and is integral to the recovery of the species. Therefore, it is critical that you minimize impacts and take steps to avoid the loss of any manatees during your transition process, as well as insure that there is no loss of manatee wintering habitat in both the near and long term.

For planning purposes, we recommend that your plan designs include identifying baseline information about the extent of warm water habitat currently used by manatees at both plants. This could include measuring the areas of warm water habitat, discharge temperatures, discharge volumes, and other parameters. The same or similar quantities of habitat will need to be provided at or in close enough proximity to these sites, such that manatees are able to find and use it with minimal disruption. In addition, any locations should include protections from human disturbance, similar to those which are currently in place. Finally, contingency plans currently under development by FWC, the Service, FP&L and others, should be completed and operational during the transition in the event that manatees do not respond as expected.

FP&L is a valued partner in the conservation and recovery of the manatee and we are confident that you will make every effort to provide for manatees as you move ahead. We look forward to working with you on this important issue, and would appreciate an opportunity to meet with you to discuss this further Please do not hesitate to contact us if you have any questions or concerns.

Sincerely,

Dave Hankla
Field Supervisor

CC: Sam Hamilton, Regional Director, Atlanta, Georgia
Ken Haddad, Director, Florida Fish and Wildlife Conservation Commission, Tallahassee, Fl

FWC STAFF REPORT FOR FLORIDA POWER AND LIGHT COMPANY – CAPE CANAVERAL ENERGY CENTER (CCEC)

Prepared by Jennifer Goff and Ron Mezich, Fish and Wildlife Biologists, July 6, 2009

This report summarizes the fish and wildlife resources that could be affected by changes to the existing power plant. It includes general recommendations for addressing these issues during the development. If you have any questions regarding the information in this report, please do not hesitate to contact Jennifer Goff at phone (561) 625-5122, or email at Jennifer.Goff@myfwc.com, or Ron Mezich at phone (850) 922-4330 or email at Ron.Mezich@myfwc.com.

PROJECT DESCRIPTION

The existing Florida Power and Light (FPL) Cape Canaveral Plan consists of two nominal 400-megawat unit conventional dual-fuel fired steam boilers that will be converted into a "modern, highly efficient, lower-emission next-generation energy center" (p. 1-1 of volume 1 of the application submittal). The project will use existing plant site boundaries, cooling water intake and discharge infrastructure, and transmission right-of-way. Construction parking and laydown will be staged on FPL-owned land adjacent to the existing Cape Canaveral Plant. The existing FPL Cape Canaveral Plant property is located on approximately 43 acres of flat, sandy area between Cocoa and Titusville in Brevard County, Florida. The site is bounded on the east by the Indian River Lagoon (Intercoastal Waterway) and on the west by U.S. Highway 1 in a portion of Section 19, Township 23, and Range 36. In addition, FPL maintains a sovereignty submerge lands lease from Florida Department of Environmental Protection (DEP) that is identified as tax Parcel Identification number 23-36-19-00-00750.0-0000.0.

The proposal utilizes the existing plant site boundaries, cooling water intake and discharge infrastructure, and transmission right-of-way. Construction parking and laydown would be staged on FPL-owned land adjacent to the existing Cape Canaveral Plant. While there would be no permanent changes in the actual footprint of the facility, this proposal requires the addition of an offsite construction laydown and parking area, and a minor upgrade to existing transmission lines/switchyard/substation to connect Cape Canaveral Energy Center (CCEC) to the FPL transmission system. Temporary changes to the thermal discharge would occur during the conversion, while the conversion would yield a permanent reduction in the CCEC's thermal discharge. The interim discharges would be to the existing intake canal located approximately 500 feet south of the current warm-water discharge area. After the conversion, the CCEC's expected thermal discharge would be approximately 25% less than at present.

POTENTIALLY AFFECTED RESOURCES

Terrestrial wildlife

This CCEC proposal does not require any permanent increase of the footprints of the associated facilities, but does propose to clear approximately 41 acres for offsite

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 18
COMPANY Florida Power & Light Company (Direct)
WITNESS R. R. Labauve (RRL-13) (Previously (RRL-9)
DATE 11/02/09

construction laydown and parking area. The proposed location for these activities contains flat, sandy soils and large areas of upland scrub, pine, and hardwood hammock habitat. There are several species on the State's threatened list that occur in this area including the gopher tortoise, Florida scrub-jay, eastern indigo snake, and Florida beach mouse and these conditions help address our concerns in regards to those species.

West Indian manatee

The manatee is listed by both the State and the USFWS as Endangered, and its use of the area surrounding the CCEC is well documented by aerial survey, mortality, and satellite telemetry data. The project site is characterized as a primary warm-water manatee refuge site due to the presence of a warm-water effluent from power plant operations. Between January 1974 and December 2008, 36 manatees have died from watercraft-related causes within a five-mile radius of the project location. In addition to the watercraft-related deaths, there have also been eight human-other, 26 perinatal, 26 cold-stress, 45 natural (other), and 68 undetermined manatee deaths within the same radius.

Historically speaking, the majority of manatees on the east coast of Florida are believed to have been limited in their distribution during cold winters to the warmer sub-tropical waters south of the Sebastian River (Moore 1951). Because of their limited ability to conserve heat, manatees cannot survive exposure to water temperatures below approximately 68° F (20°C) for extended periods of time (Marine Mammal Commission 1988). In north and central Florida, water temperatures in winter periodically drop below 68° F. During these periods, manatees seek out warm-water sources. The power plants and other industries that discharge large volumes of warm water into Florida's coastal bays and estuaries provide manatees with warm-water refugia (Campbell and Irvine 1981, O'Shea et al. 1985). Since the introduction of these warm-water sources, more manatees have used Brevard County waters during the winter months.

With the presence of a warm-water refuge, ample forage, and protected areas in the north Banana River, Brevard County hosts a significant year-round manatee population. Spring and winter aggregations are the largest documented in the State. Spring aggregations in the north Banana River alone have exceeded 365 manatees (Jane Provancha, personal communication), while winter surveys at thermal discharges from the two power plants in Brevard County have documented a high count of 588 manatees during a single flight (Reynolds 2004).

The conversion of the CCEC would result in the temporary discontinuation of the existing thermal discharge and manatee warm-water refuge; however, the construction of an interim heating system would allow for continuation of a warm-water refuge for manatees near the CCEC. The temporary discontinuation of the existing thermal discharge and the relocation of the warm-water refuge to a nearby location will modify manatee warm-water habitat and require manatees to adapt to this change.

Due to the dependence of numerous manatees on the warm-water habitat provided by the CCEC, permit conditions addressing the interim heating system, the temporary warm-water refuge, and the return to the historic site after reconstruction are being recommended. In addition, FWC is also recommending that FPL provide for monitoring of environmental and biological indicators that will play a substantial role in determining the status of the interim heating system during the conversion. These monitoring conditions will assist FWC's efforts to monitor the health status of manatees and provide an early warning system for cold stress complications and contingency planning to help mitigate the potential loss of significant numbers of manatees if there is a failure in the interim warm-water heating system.

Conclusion - Manatees

Florida manatees have used the Cape Canaveral plant's thermal discharge during the winter months for decades. The thermal discharge from this plant has been consistent and reliable, thereby allowing manatees to become dependent on it. At the time the Manatee Power Plant Protection Plan (MPPPP) was developed for this plant, the FWC, USFWS, and FPL agreed upon a 61°F ambient water trigger temperature based on a negotiation of several factors. This trigger temperature requires the plant to operate at least one unit to create a warm-water refuge for manatees during the winter months when ambient water temperatures reach the trigger temperature. The ambient water temperature that was selected was based on several criteria: 1) Base Load Operation, with the Cape Canaveral Plant operating as a base load unit (running consistently and creating a dependable warm-water refuge), 2) economics (potential costs to FPL) and 3) manatee biology (how often and how long would manatees be subjected to temperatures between 68°F and 61°F). Two of these three factors have recently changed and will change even further during the conversion process. The warm water discharge at the Cape Canaveral Plant has been less consistent, and the interim refuge may be even less dependable for manatees if operated at a 61° F trigger temperature. The reduced dependability of the warm-water refuge may increase the frequency of exposure of manatees to cold water and escalate the risk of cold stress disease and death since the proposed interim heating system has not been implemented previously.

The USFWS advised the licensee in August 2008 that take of manatees is not authorized during the proposed plant conversion at the CCEC (See Attachment A). As a result FWC has attempted to develop appropriate measures and conditions to prevent take of manatees during reconstruction of the plant, which includes the interim refuge. We have worked as closely as possible with the licensee to develop these conditions.

RECOMMENDATIONS

We recommend the following Conditions of Certification:

Terrestrial Wildlife

1. All undeveloped habitat onsite shall be surveyed for the presence of state- and federally listed species no more than six months before land clearing and the results shall be reported to the FWC. We recommend that the report includes methodology, results, discussion, and references to all survey protocols and documents used. If there is evidence that any state-listed species are present, then the licensee must report the findings to the FWC. If impacts to those species cannot be avoided, then the licensee must contact the FWC before taking any action that might result in an impact to those species.

2. Gopher tortoises found onsite shall be relocated in accordance with the state Gopher Tortoise Management Plan. Pursuant to the requirements of Rules 68A-25.002 and 68A-27.004, Florida Administrative Code, a permit for a gopher tortoise capture/relocation/release activity must be secured from the FWC before beginning any relocation work. Such permits will be issued pursuant to any and all applications which sufficiently accommodate these guidelines. Application forms to be used are available from the Permit Coordinator, Species Conservation Planning Section, Florida Fish and Wildlife Conservation Commission, 620 S. Meridian St., Mail Station 2A, Tallahassee, FL 32399-1600, (850)410-0656, ext. 17327/ (850)488-5297 fax or from the FWC's web site at http://myfwc.com/permits/Protected-Wildlife/. Complete applications should be submitted to the Gopher Tortoise Permit Coordinator at the above address at least 45 days before the time needed.

3. Before clearing, FPL shall coordinate with the USFWS and the FWC regarding appropriate measures to address impacts to scrub-jay habitat.

   [Article IV, Sec. 9, Fla. Const.; Chapter 68A-27, F.A.C.]

West Indian Manatee

Interim Warm-Water Refuge Heating System

4. The current trigger temperature identified in the Manatee Protection Plan under the Cape Canaveral power plant's National Pollutant Discharge Elimination System permit is 61°F. In order to prevent an increased risk of manatee cold stress death during the CCEC conversion construction period, adaptive management protocols for the interim warm-water refuge heating system shall include the following:

   a. Testing, monitoring, and evaluation of the interim heating system shall take place pursuant to the permit conditions found in the Environmental Monitoring and Biological sections.

b. The trigger temperature shall be set at 65°F, during the period that the interim heating system is required. The interim heating system shall be designed such that when ambient water temperatures are below 65°F, as indicated from a selected ambient water temperature station (as agreed to in the environmental monitoring plan), the interim heating system will provide a water temperature at or above 68°F, within the identified warm-water refuge until such time as the ambient water temperature reaches 65°F. The interim heating system shall be maintained and operated to achieve this result, in accordance with best management practices (BMP) established by Licensee, unless otherwise authorized by FWC and USFWS, or unless the safety or reliability of the electric power system would be compromised. Licensee shall develop a BMP manual for the interim heating system that shall include the following components:

   i. operation and maintenance procedures for the interim heating system;
   ii. requirement for a log demonstrating that the recommended operating and maintenance procedures and checks are performed;
   iii. a spare parts list including the location of the spares;
   iv a list of qualified operators and repair persons and their contact information;
   iv. a trouble shooting flowchart and repair personnel call out plan;
   v. an incident log to track the status of troubleshooting and repair activities until the system is operable;
   vi. notification requirements to agencies.

   Licensee shall submit its BMP manual to FWC for review and comment by August 15, 2010. Licensee will review, consider, and incorporate if practicable, comments from FWC that are received by September 15, 2010. A copy of the Licensee's BMP manual for the interim heating system shall be maintained at all times at the CCEC site and shall be made available upon request to authorized representatives of FWC and DEP.

c. If through the biological monitoring or daily visual assessments of manatee health, or scientific data it is indicated, that the 65°F interim heating system trigger temperature should be; raised or lowered to maintain a sufficient warm-water refuge, then DEP will meet with FWC, USFWS, and FPL to assess the information and develop a new strategy that can be agreed upon by all four parties. Such a new agreed upon strategy would be proposed in a DEP initiated modification to certification, in consultation with FWC, USFWS and FPL.

d. The interim warm-water refuge is described as the area located within the current Cape Canaveral plant intake canal beginning at the western most extent of the canal and including all waters within the canal between the peninsula and the southern shoreline up to the southern shoreline's eastern most point (See attachment B and C).

[Sections 403.507 and 403.509, F.S.; Section 379.1025 F.S., Section 379.2291 F.S., Section 379.2431 (2) F.S., Section 20.331 F.S., Section 253.75 F.S., Rules 68A-27 Florida Administrative Code.]

The Licensee may request modification of the following applicable FWC conditions upon issuance by the Department of Environmental Protection, in consultation with the FWC, of Final NPDES permit modification FL0001473 if such requested modifications to the conditions herein have been adopted into the Final NPDES permit.

Environmental Monitoring

5. The following monitoring requirements are applicable to the interim warm-water refuge period and two years post commercial operation of CCE-C:

   a. Within 180 days following certification of the CCEC, the Licensee (Florida Power & Light Company) shall submit to the FWC, Florida Department of Environmental Protection (DEP) Siting Office, and the USFWS an Environmental Monitoring Plan. The Environmental Monitoring Plan shall include, at a minimum, the following components:

      i. An evaluation of the interim heating system to determine its ability to provide a sufficient manatee warm-water refuge (as described in conditions 4 and 5, and the Licensee's Thermal Modeling Study) during the winter months shall take place prior to discontinuation of the current warm-water discharge. Evaluation of the system shall include its performance during cold fronts and varying tidal and wind conditions, if present, for a duration to be established in the Environmental Monitoring Plan.

      ii. If an interim heating system is installed at Riviera Beach Energy Center (RBEC) in 2009 an initial evaluation of the interim heating system, during winter conditions, shall be conducted there.

      iii. The interim heating system at the CCEC site shall be installed and operational by September 15, 2010 or as soon as practicable after certification, whichever is later. However, the conversion from the existing system to the interim system cannot be implemented during the winter months (November through March). The warm-water refuge created by this system shall be monitored during initial testing at the CCEC site between September 15 and October 15, 2010, or the duration described in 5.a.i. and the empirical temperature data will be collected and compared to the thermal modeling results to evaluate the performance of the interim heating system and the accuracy of the thermal model.

      iv. Monitoring of the CCEC's interim warm-water refuge during the conversion shall consist of winter (October 15 through March 31) ambient air and water temperatures measured at multiple locations within the interim warm-water refuge. The number and configuration of temperature monitoring stations must be sufficient to provide a three-dimensional view, over time, of the thermal plume.

v. Monitoring of the CCEC's post-conversion warm-water refuge shall consist of winter ambient air and water temperatures measured at multiple locations within the warm-water refuge. Monitoring for the first post conversion winter shall take place from October 15 through March 31 and from November 15 through March 31 during the second winter post construction. The number and configuration of temperature monitoring stations must be sufficient to provide a three-dimensional view, over time, of the thermal plume.

vi. Temperature monitoring stations will be deployed during the conversion phase in the interim refuge and post-conversion warm-water refuge. As part of this Environmental Monitoring Plan as described in this Section 5., the Licensee shall include a plan to convey the data from the temperature monitoring stations to the appropriate agencies on a daily basis when the trigger is on and the heaters are running and on a weekly basis when the ambient temperature is greater than 65 degrees.

vii. Specific locations for the temperature monitoring station(s), sampling frequencies, station depths data collection methods, and reporting frequencies must be identified and may be subject to further revision depending on receipt of any required permits, licenses and approvals.

viii. The Environmental Monitoring Plan, including the proposed monitoring locations, shall be approved prior to implementation. DEP, in consultation with the FWC and USFWS, shall indicate its approval or disapproval of the submitted plan within 90 days of the originally submitted information. In the event that additional information from the licensee is necessary to complete and approve the Plan, DEP, in consultation with the FWC and USFWS, shall make a written request to the licensee for additional information no later than 30 days after receipt of the submitted information. A final plan shall be in place by September 1, 2010.

b. The Licensee will prepare an environmental monitoring report that includes all data (made available in electronic form) and statistical analyses collected as a result of the environmental monitoring requirements. This report will be submitted yearly, by August 1 of each year, while the interim warm-water system is in operation during the construction period and two years post-conversion of the CCEC. Within 180 days of the submittal of the final yearly environmental monitoring report, a summary report of all environmental monitoring shall be completed and submitted to the FWC, and DEP Siting Office for review.

c. If, in the review of the annual environmental monitoring reports, DEP, in consultation with the FWC and USFWS, determines the need to modify the Environmental Monitoring Plan, DEP will notify the Licensee to discuss the findings. At that time, DEP, in consultation with the FWC and USFWS and the Licensee, will determine what, if any, modifications need to be made to the Environmental Monitoring Plan and DEP will initiate modifications to certification if necessary.

d. If by June 1, 2010, the initial monitoring tests of the interim warm-water heating system have taken place at the Riviera Beach power plant, the Licensee will contact DEP and FWC to provide and discuss the results. At that time, DEP, in consultation with the FWC and USFWS, and the Licensee, will determine what, if any, modifications need to be made to the operation of the interim heating systems and DEP will initiate a modification to certification if necessary.

e. By November 1, 2010, or two weeks after completion of the initial monitoring test of the interim warm-water heating system at the CCEC, the Licensee will contact DEP, FWC and USFWS to provide and discuss the results. At that time, DEP, in consultation with the FWC, USFWS, and the Licensee, will determine what, if any, modifications need to be made to the operation of the interim heating system and DEP will initiate a modification to certification if necessary.

f. If the Licensee determines the Environmental Monitoring Plan is in need of modifications during the operation of the interim heating system, the Licensee will contact the agencies to discuss the proposed modifications. At that time, DEP, in consultation with the FWC and USFWS and the Licensee, will determine what if any modifications need to be made to the Environmental Monitoring Plan and the DEP shall initiate a modification to certification if necessary.

[Sections 403.507 and 403.509, F.S.; Section 379.1025 F.S., Section 379.2291 F.S., Section 379.2431 (2) F.S., Section 20.331 F.S., Section 253.75 F.S., Rules 68A-27 Florida Administrative Code.]

Biological Monitoring

6. The following monitoring requirements for manatee distribution and abundance are applicable to the interim warm-water refuge and two year post-commercial operation of CCEC:

a. Within 180 days following certification of the CCEC, the Licensee shall submit to the DEP Siting Office and FWC, a Biological Monitoring Plan. The Biological Monitoring Plan shall include at a minimum the following components:

   i. Monitor the winter (October 15 through March 31) distribution and abundance of manatees during the time frame that includes the operation of the interim warm-water heating system. Monitor the winter (November 15 through March 31) distribution and abundance of manatees during the two years' post-conversion at the CCEC warm-water refuge.

   ii. Biological monitoring shall at a minimum be conducted through aerial surveys and telemetry tagged manatees.

   iii. Specific aerial survey paths, sampling frequencies, and methodologies for aerial surveys. At a minimum, aerial survey flight paths shall encompass known manatee winter habitat including travel corridors and passive warm-water sites throughout Brevard County on a weekly basis during the interim period during the winter months (October 15 through March 31). Once the converted CCEC is in operation the aerial surveys shall be conducted on a twice a month basis for two years post commercial operation during the winter months. After the first year of post conversion surveys FWC will discuss the results with the Licensee and determine if the second year's surveys can be reduced to one survey per month.

   iv. Aerial surveys shall be designed so the data collected will provide an evaluation of manatee abundance and distributional changes in Brevard County in a statistically valid manner that is consistent with past aerial survey data.

   v. Telemetry monitoring shall be accomplished by the Licensee through the use of FWC or another entity with experience in manatee telemetry tracking, and data analysis in Florida by providing them $50,000 per winter season to be used for the purchase of up to three tags annually, if needed, and the accompanying annual activities and research, tracking and monitoring activities, data collection, ARGOS usage, software purchase and update, and one final report to the Licensee. This condition will coincide with the use of the interim heating system and 2 years post-commercial operation of CCEC. After the first year of post conversion telemetry monitoring FWC will discuss the results with the Licensee and the parties will determine if the second year's monitoring can be eliminated. The tags will be attached to manatees captured at, or near the CCEC site to document their movements to secondary warm-water sites, nighttime habitat use, behavioral response to changes in the operation of the interim refuge (e.g., availability of warm-water discharge in relation to the trigger temperature), and thermal regime experienced by manatees during the conversion of CCEC. The details of the telemetry effort will be provided in the biological monitoring plan and, if requested by the licensee, FWC and USFWS can provide assistance.

vi. The Biological Monitoring Plan shall be reviewed and approved prior to implementation. DEP, in consultation with the FWC and USFWS, shall indicate its approval or disapproval of the submitted plan within 90 days of the originally submitted information. In the event that additional information from the licensee is necessary to complete and approve the Plan, DEP, in consultation with the FWC and USFWS, shall make a written request to the Licensee for additional information no later than 30 days after receipt of the submitted information. A final plan shall be in place by September 1, 2010.

b. The Licensee shall provide a manatee observer(s) who has sufficient experience in detecting indicators of cold stress in manatees. The monitoring protocols and individuals acting as manatee observer(s) will require approval from the FWC.

c. The manatee observer will be required to conduct a daily visual assessment of the condition and general distribution of manatees using the interim warm-water refuge during the winter months (October 15 through March 31) during the interim period. The visual assessments shall be conducted for a sufficient length of time to assess most of the manatees present at the plant and accessible to the observer on that day. If an approved observer is not available, licensee shall notify FWC as soon as possible, but no later than 48 hours, to coordinate actions necessary to resume the observation program.

d. The Licensee shall provide two moveable land-based observation platforms located along the interim warm-water refuge. These will be used by the manatee observer(s) for conducting assessments of cold stress symptoms and by FWC or USFWS staff monitoring manatee use of the interim refuge through photo identification.

e. The Licensee will prepare a biological monitoring report that includes all data (made available in electronic form) and statistical analyses completed as a result of the requirements set forth in the biological monitoring plan. This report will be submitted yearly, by August 1 of each year, when the interim warm-water system is in operation during the construction period and two years post-commercial operation date. Within 180 days of submittal of the final yearly biological monitoring report a summary of all biological monitoring reports shall be completed and submitted to the FWC and DEP Siting Office for review.

f. If, in the review of the biological monitoring reports, DEP, in consultation with FWC and USFWS, determines the need to modify the Biological Monitoring Plan, DEP will notify the Licensee to discuss the findings. At that time, DEP, in consultation with the FWC and USFWS, and the Licensee will determine what if any modifications need to be made to the Biological Monitoring Plan and the DEP will initiate a modification to certification if necessary.

g. If the Licensee determines the Biological Monitoring Plan is in need of modifications during the operation of the interim heating system, the Licensee will contact the agencies to discuss the proposed modifications. At that time, DEP, in consultation with the FWC and USFWS, and the Licensee will determine what, if any modifications need to be made to the Biological Monitoring Plan and the DEP will initiate a modification to certification if necessary.

h. The Licensee will provide personnel from the FWC, USFWS, USGS Sirenia Project, or a designee of these agencies, access to the CCEC property to conduct manatee monitoring activities. Reasonable notice shall be given to the Licensee by the agencies. Access would be limited to normal weekday business hours (8:00 a.m. - 5:00 p.m.) unless arrangements are made in advance with the Licensee.

[Sections 403.507 and 403.509, F.S.; Section 379.1025 F.S., Section 379.2291 F.S., Section 379.2431 (2) F.S., Section 20.331 F.S., Section 253.75 F.S., Rules 68A-27 Florida Administrative Code.]

Contingency Plan

7. FWC and USFWS' LOA (Letter of Authorization) network responders will be responsible for all efforts related to manatee rescues, rehabilitation activities, and carcass recovery during the CCEC conversion. In order to effectively implement contingency plans during the plant conversion and to address manatee health-related issues due to a malfunction or inability of the interim warm-water heating system to effectively provide a warm-water refuge during the winter months (October 15 through March 31), the following conditions are required:

   a. If the observer (pursuant to conditions 6.b., c. and d.) identifies manatees with apparent signs of cold stress disease, digital photographs should be taken of the animal(s) and the FWC shall be called as soon as possible on the day of the observations through the following methods. An FWC biologist can be reached via pager at 800-714-0620 (enter the callers contact number followed by the code "02". A page will be returned within 30 minutes; if not, resend the page. For immediate emergency situations FWC's Wildlife Alert number can also be called at 888-404-FWCC.

b. The Licensee will notify FWC and USFWS immediately if there is a mechanical failure of the interim heating system, or if, for any other reason the interim heating system is not operating in a manner that will provide warm-water sufficient to keep the warm-water refuge at a temperature of 68° F or greater.

c. The Licensee shall provide in-kind services and financial assistance, not to exceed $100,000 in total value, to FWC for manatee rescue or recovery in the event that there is a failure of the interim heating system resulting from Licensee's failure to comply with Condition 4.b. that causes death or identifiable cold stress to manatees in Brevard County. This condition would apply during the winter months (October 15 through March 31). The in-kind assistance and funds would only be used to address manatee-related cold stress issues in the area that the interim system affects.

d. The Licensee will provide personnel from the FWC, USFWS, USGS-Sirenia Project, or a designee of these agencies, access to the CCEC property to conduct manatee monitoring activities. Reasonable notice shall be given to the licensee by the agencies. Access would be limited to normal weekday business hours (8:00 a.m. - 5:00 p.m.) unless arrangements are made in advance with the Licensee.

e. The Licensee will include as part of its safety orientation manatee awareness training for full-time permanent construction personnel at the CCEC site. This training will be designed to educate the construction work force about the legal requirements to avoid manatees and to provide them with contact information if they should spot an injured manatee.

f. All visitors to CCEC will be required to comply with FPL's safety and security requirements. Personnel will receive an orientation from FPL or its contractor prior to commencing observations or other activities.

[Sections 403.507 and 403.509, F.S.; Section 379.1025 F.S., Section 379.2291 F.S., Section 379.2431 (2) F.S., Section 20.331 F.S., Rules 68A-27 Florida Administrative Code.]

Development of a Long-Term Manatee Strategy

8. It is expected that at some point in the future the warm-water habitat created by the CCEC will diminish or be terminated in that event the FWC and USFWS believes it is in the best interest of the Licensee, FWC, USFWS, DEP, and the Florida manatee population to begin strategic long term planning to reduce the adverse affects to the Florida manatee population before this occurs.

   a. Within two years of the formal approval by FWC and USFWS of a Warm-Water Action Plan (Plan), inclusive of a future-oriented Management Policy for Warm-Water Manatee Habitat, the Licensee shall host and chair a workshop designed to: (a) articulate a strategy for achieving the goals of that Plan, (b) develop a timetable for implementing the strategy, (c) review progress to date in achieving the strategy, and (d) identify impediments and solutions.

b. Within one year of the workshop held pursuant to Condition 1, the Licensee shall provide the FWC and USFWS with a formal report of the workshop, including findings, conclusions, and recommendations.

c. Over the course of the operating life span of the CCEC the Licensee shall develop an exit strategy for the CCEC that prevents significant losses to the manatee population when the Licensee determines reduce or eliminate the CCEC's thermal discharge to the extent that a dependable warm-water refuge is no longer present. The Licensee's strategy shall consider FWC and USFWS's statewide Warm-Water Action Plan approved by FWC and USFWS.

d. The Licensee shall work closely with the FWC and USFWS to evaluate progress toward achieving the vision and goals of the Warm-Water Action Plan and to develop adaptive changes to the Plan as needed to promote manatee recovery through participation in periodic workshops and/or conferences designed to accomplish such evaluation and adaptive changes.

Manatee Construction Conditions For In-Water Work

9. The Standard Manatee Conditions for In-Water Work (revision 2009) are required for all in-water work in or adjacent to waters accessible to manatees. Blasting or pile hammering activities to break rock shall be prohibited in waters accessible to manatees. If no other alternative exists, a modification of these conservation measures can be requested. An adequate Blast and Protected Species Watch Plan must be submitted to and approved by the Imperiled Species Management Section of the FWC prior to these methodologies being used.

10. To reduce the possibility of injuring or killing a manatee during construction, in-water work shall not be performed between November 15 and March 31 unless essential to support the CCEC project's schedule. If in-water work during the winter cannot be avoided the Licensee will contact the agencies to determine alternative conditions that will be implemented to address the proposed activity.

11. At least one person shall be designated as a manatee observer when in-water work is being performed. That person shall have experience in manatee observation, be approved by the FWC two weeks before the beginning of construction, and be equipped with polarized sunglasses to aid in observation. The manatee observer must be on site during all in-water construction activities and will advise personnel to cease operation upon sighting a manatee within 50 feet of any in-water construction activity. Movement of a work barge, other

associated vessels, or any in-water work shall not be performed after sunset, when the possibility of spotting manatees is negligible. Observers shall maintain a log detailing manatee sightings, work stoppages, and other protected species-related incidents. A report, summarizing all activities noted in the observer logs, the location and name of project, and the dates and times of work shall be submitted within 30 days following project completion, to the FWC's Imperiled Species Management Section at: 620 South Meridian Street, 6A, Tallahassee, Florida 32399-1600, or e-mailed at fcmpmail@myfwc.com.

To reduce the risk of entrapment and drowning of manatees, grating shall be installed over any existing or proposed pipes or culverts greater than 8 inches, but smaller than 8 feet in diameter that are submerged or partially submerged and reasonably accessible to manatees. Bars or grates no more than 8 inches apart shall be placed on the accessible end(s) during all phases of the construction process and as a final design element to restrict manatee access.

[Sections 403.507 and 403.509, F.S.; Section 379.1025 F.S., Section 379.2291 F.S., Section 379.2431 (2) F.S., Section 20.331 F.S., Rules 68A-27 Florida Administrative Code.]

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Marine Mammal Commission. 1988. Preliminary Assessment of Habitat Protection Needs for West Indian Manatees on the East Coast of Florida and Georgia. Rept. of the Marine Mammal Commission in Consultation with its Committee of Scientific Advisors on Marine Mammals. pp.1-107.

Moore, J.C. 1951b. The Range of the Florida Manatee. The Quarterly Journal of the Florida Academy of Sciences. Volume 14, No. 1. pp.1-18.

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Reynolds, J.E., III. 2004. Distribution and Abundance of Florida Manatees (*Trichechus manatus latirostris)* Around Selected Power Plants Following Winter Cold Fronts. 2002-2003. Final Report Prepared For FP&L Company, Juno Beach, FL. Order Number 4500004663: 48 pp.

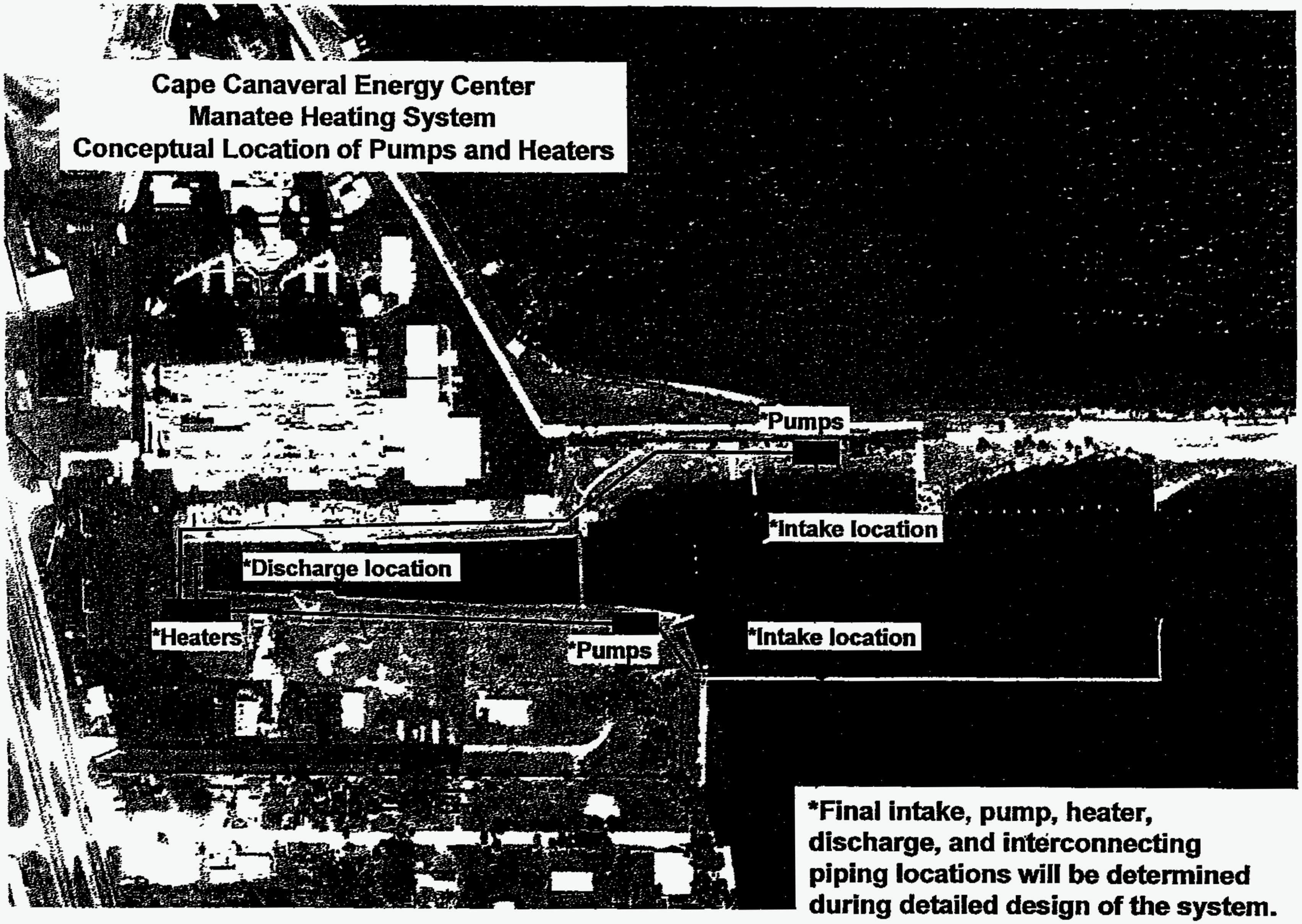
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 090007-EI EXHIBIT 19

COMPANY Florida Power & Light Company (Direct)

WITNESS R. R. Labauve (RRL-14) (Previously RRL-10)

DATE 11/02/09



Docket No. 090007-EI
Manatee Heating System Conceptual Location of Pumps and Heater
Exhibit RRL-14, Page 1 of 1

Form Appendix

EXHIBIT 1 (WG-1)

PROGRESS ENERGY FLORIDA, INC.
ENVIRONMENTAL COST RECOVERY
COMMISSION FORMS 42-1A THROUGH 42-8A

JANUARY 2008 - DECEMBER 2008
FINAL TRUE-UP
DOCKET NO. 090007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 20
COMPANY Progress Energy Florida, Inc.
WITNESS Will Garrett (WG-1)
DATE 11/02/09

Form 42-1A

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2008 through December 2008
(in Dollars)

Line		Period Amount
1	Over/(Under) Recovery for the Period January 2008 through December 2008 (Form 42-2A, Line 5 + 6 + 7 + 11)	$ (14,193,035)
2	Estimated/Actual True-Up Amount approved for the period January 2008 through December 2008 (Order No. PSC-08-0775-FOF-EI)	(9,872,429)
3	Final True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2010 to December 2010 (Lines 1 - 2)	**$ (4,320,606)**

Form 42-2A

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2008 through December 2008

End-of-Period True-Up Amount
(in Dollars)

Line	Description		Actual January 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	End of Period Total
1	ECRC Revenues (net of Revenue Taxes)		$3,064,100	$2,828,489	$2,803,681	$2,981,102	$3,193,738	$3,940,477	$3,744,710	$4,053,314	$4,406,756	$3,468,274	$3,183,014	$3,509,067	$41,176,721
2	True-Up Provision	($886,816)	(73,901)	(73,901)	(73,901)	(73,901)	(73,901)	(73,901)	(73,901)	(73,901)	(73,901)	(73,901)	(73,901)	(73,901)	(886,816)
3	ECRC Revenues Applicable to Period (Lines 1 + 2)		2,990,199	2,754,588	2,729,779	2,907,200	3,119,837	3,866,576	3,670,809	3,979,413	4,332,855	3,394,372	3,109,112	3,435,165	40,289,905
4	Jurisdictional ECRC Costs														
	a. O & M Activities (Form 42-5A, Line 9)		2,910,716	2,908,273	3,793,525	3,692,843	3,874,070	4,308,114	4,399,539	4,477,670	3,345,481	2,894,941	2,236,403	3,049,480	41,891,055
	b. Capital Investment Projects (Form 42-7A, Line 9)		626,711	854,785	725,996	912,241	1,058,163	1,168,028	1,188,324	1,187,205	1,187,536	1,185,334	1,199,029	1,246,031	12,539,382
	c. Total Jurisdictional ECRC Costs		3,537,427	3,763,058	4,519,521	4,605,084	4,932,233	5,476,142	5,587,863	5,664,875	4,533,017	4,080,275	3,435,432	4,295,511	54,430,437
5	Over/(Under) Recovery (Line 3 - Line 4c)		(547,228)	(1,008,470)	(1,789,742)	(1,697,884)	(1,812,396)	(1,609,566)	(1,917,054)	(1,685,463)	(200,162)	(685,903)	(326,319)	(860,346)	(14,140,532)
6	Interest Provision (Form 42-3A, Line 11)		14,916	9,638	5,794	1,757	(2,000)	(5,173)	(8,655)	(12,196)	(21,114)	(23,821)	(14,256)	(6,996)	(62,106)
7	Adjustments to Period Including Interest		0	0	0	0	0	0	0	0	9,603	0	(9,603)	9,603	9,603
8	Beginning Balance True-Up & Interest Provision		(886,816)	(1,345,227)	(2,270,158)	(3,980,204)	(5,602,430)	(7,342,924)	(8,883,761)	(10,735,569)	(12,359,327)	(12,497,099)	(13,132,921)	(13,409,198)	(886,816)
	a. Deferred True-Up from January 2007 to December 2007 (Order No. PSC-07-0922-FOF-EI)		5,562,717	5,562,717	5,562,717	5,562,717	5,562,717	5,562,717	5,562,717	5,562,717	5,562,717	5,562,717	5,562,717	5,562,717	5,562,717
9	True-Up Collected/(Refunded) (see Line 2)		73,901	73,901	73,901	73,901	73,901	73,901	73,901	73,901	73,901	73,901	73,901	73,901	886,816
10	End of Period Total True-Up (Lines 5+6+7+8+8a+9)		4,217,490	3,292,560	1,582,512	(39,712)	(1,780,207)	(3,321,045)	(5,172,852)	(6,796,610)	(6,943,985)	(7,570,204)	(7,846,481)	(8,630,318)	(8,630,318)
11	Adjustments to Period Total True-Up Including Interest		0	0	0	0	0	0	0	0	0	0	0	0	0
12	End of Period Total True-Up (Lines 9 + 10)		$4,217,490	$3,292,560	$1,582,512	($39,712)	($1,780,207)	($3,321,045)	($5,172,852)	($6,796,610)	($6,943,985)	($7,570,204)	($7,846,481)	($8,630,318)	($8,630,318)

Form 42-3A

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2008 through December 2008

Interest Provision
(in Dollars)

Line	Description	Actual January 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	End of Period Total
1	Beginning True-Up Amount (Form 42-2A, Line 7 + 8 + 8a + 11)	**$4,675,901**	$4,217,490	$3,292,559	$1,582,513	($39,713)	($1,780,207)	($3,321,044)	($5,172,852)	($6,787,007)	($6,934,382)	($7,579,807)	($7,836,878)	
2	Ending True-Up Amount Before Interest (Line 1 + Form 42-2A, Lines 5+9)	4,202,574	3,282,921	1,576,719	(41,469)	(1,778,207)	(3,315,871)	(5,164,197)	(6,784,414)	(6,913,268)	(7,546,383)	(7,832,225)	(8,623,323)	
3	Adjustments to Period Including Interest	0	0	0	0	0	0	0	0	(9,816)	0	0	0	
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	8,878,475	7,500,412	4,869,279	1,541,044	(1,817,920)	(5,096,079)	(8,485,242)	(11,957,266)	(13,710,090)	(14,480,765)	(15,412,032)	(16,460,201)	
4	Average True-Up Amount (Line 3 x 1/2)	4,439,238	3,750,206	2,434,640	770,522	(908,960)	(2,548,040)	(4,242,621)	(5,978,633)	(6,855,046)	(7,240,383)	(7,706,016)	(8,230,101)	
5	Interest Rate (First Day of Reporting Business Month)	4.98%	3.08%	3.09%	2.63%	2.84%	2.43%	2.45%	2.44%	2.45%	4.95%	2.95%	1.49%	
6	Interest Rate (First Day of Subsequent Business Month)	3.08%	3.09%	2.63%	2.84%	2.43%	2.45%	2.44%	2.45%	4.95%	2.95%	1.49%	0.54%	
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	8.06%	6.17%	5.72%	5.47%	5.27%	4.88%	4.89%	4.89%	7.40%	7.90%	4.44%	2.03%	
8	Average Interest Rate (Line 7 x 1/2)	4.030%	3.085%	2.860%	2.735%	2.635%	2.440%	2.445%	2.445%	3.700%	3.950%	2.220%	1.015%	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.336%	0.257%	0.238%	0.228%	0.220%	0.203%	0.204%	0.204%	0.308%	0.329%	0.185%	0.085%	
10	Interest Provision for the Month (Line 4 x Line 9)	$14,916	$9,638	$5,794	$1,757	($2,000)	($5,173)	($8,655)	($12,196)	($21,114)	($23,821)	($14,256)	($6,996)	**($62,106)**

Form 42 4A

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2008 through December 2008

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 Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$2,581,940	$1,733,861	$848,079	49%
	1a Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	3,325,716	3,193,542	132,174	4%
	2 Distribution System Environmental Investigation, Remediation, and Pollution Prevention	19,416,714	15,348,112	4,068,602	27%
	3 Pipeline Integrity Management	504,671	483,057	21,614	4%
	4 Above Ground Tank Secondary Containment	371,438	368,303	3,135	1%
	5 SO2/NOx Emissions Allowances	13,878,857	14,911,514	(1,032,657)	-7%
	6 Phase II Cooling Water Intake	124,779	109,372	15,407	14%
	7.2 CAIR/CAMR - Peaking - Demand	0	0	0	N/A
	8 Arsenic Groundwater Standard - Base	0	0	0	N/A
	9 Sea Turtle - Coastal Street Lighting - Distrib	110,572	106,711	3,861	4%
	11 Modular Cooling Towers - Base	3,336,752	3,336,752	0	0%
	12 Greenhouse Gas Inventory and Reporting - Energy	7,718	7,440	278	4%
	13 CAIR A&G	35,605	0	35,605	100%
2	Total O&M Activities - Recoverable Costs	**$43,694,761**	**$39,598,664**	**$4,096,097**	10%
3	Recoverable Costs Allocated to Energy	13,886,574	14,918,954	(1,032,657)	-7%
4	Recoverable Costs Allocated to Demand	29,808,187	24,679,710	5,128,754	21%

Notes:

Column (1) is the End of Period Totals on Form 42-5A
Column (2) = Estimated actual
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Form 42-5A

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2008 through December 2008

O&M Activities
(in Dollars)

Line	Description	Actual January 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	End of Period Total
1	Description of O&M Activities													
	1 Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$61,886	$59,344	$394,789	$317,657	$233,421	$311,208	$71,316	$198,538	$228,191	$267,526	$188,420	$249,644	$2,581,940
	1a Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	178,491	452,322	121,795	(1,852)	605,200	174,267	463,699	321,024	154,717	179,338	442,958	233,757	3,325,716
	2 Distribution System Environmental Investigation, Remediation, and Pollution Prevention	1,353,452	1,216,372	1,817,242	2,336,394	1,981,067	1,698,585	1,858,800	2,075,110	1,146,712	1,627,938	836,358	1,468,685	19,416,714
	3 Pipeline Integrity Management, Review/Update Plan and Risk Assessments - Intm	4,150	91,848	14,562	18,639	30,437	16,110	32,767	18,867	20,184	23,046	6,824	227,239	504,671
	4 Above Ground Tank Secondary Containment - Pkg	270	190	367,843	0	0	0	0	0	0	1,520	1,615	0	371,438
	5 SO2 Emissions Allowances	1,352,540	1,169,177	1,272,389	1,147,204	1,166,931	1,392,505	1,294,040	1,206,366	1,105,790	932,138	844,942	994,835	13,878,857
	6 Phase II Cooling Water Intake 316(b) - Base	12,792	0	13,129	12,791	0	347	0	0	0	0	0	0	39,058
	6a Phase II Cooling Water Intake 316(b) - Intm	25,751	0	0	7,896	6,466	202	653	1,227	38,533	(31)	10,050	(5,025)	85,720
	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	351	1,420	291	(351)	0	102,000	164	4,266	2,254	178	0	0	110,572
	11 Modular Cooling Towers - Base	0	0	0	0	0	834,188	834,188	834,188	834,188	0	0	0	3,336,752
	12 Greenhouse Gas Inventory and Reporting - Energy	0	0	0	0	0	0	0	0	0	0	0	7,718	7,718
	13 CAIR	0	0	0	0	0	0	0		0	0	0	35,605	35,605
2	Total of O&M Activities	2,989,682	2,990,672	4,002,039	3,838,377	4,023,522	4,529,411	4,555,627	4,659,585	3,530,568	3,031,654	2,331,167	3,212,458	$43,694,761
3	Recoverable Costs Allocated to Energy	1,352,540	1,169,177	1,272,389	1,147,204	1,166,931	1,392,505	1,294,040	1,206,366	1,105,790	932,138	844,942	1,002,552	13,886,574
4	Recoverable Costs Allocated to Demand - Transm	61,886	59,344	394,789	317,657	233,421	311,208	71,316	198,538	228,191	267,526	188,420	249,644	2,581,940
	Recoverable Costs Allocated to Demand - Distrib	1,532,294	1,670,114	1,939,328	2,334,190	2,586,268	1,974,852	2,322,663	2,400,399	1,303,683	1,807,454	1,279,316	1,702,442	22,853,002
	Recoverable Costs Allocated to Demand - Prod-Base	12,792	0	13,129	12,791	0	834,535	834,188	834,188	834,188	0	0	0	3,375,810
	Recoverable Costs Allocated to Demand - Prod-Intm	30,171	92,038	14,562	26,534	36,902	16,312	33,420	20,094	58,716	24,535	18,489	222,214	593,987
	Recoverable Costs Allocated to Demand - Prod-Peaking	0	0	367,843	0	0	0	0	0	0	1,520	1,615	0	370,978
	Recoverable Costs Allocated to Demand - A&G	0	0	0	0	0	0	0	0	0	0	0	35,605	35,605
5	Retail Energy Jurisdictional Factor	0.96490	0.96670	0.96840	0.96830	0.94630	0.95240	0.94850	0.95230	0.95630	0.94960	0.96240	0.96690	
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	
	Retail Production Demand Jurisdictional Factor - A&G	0.91670	0.91670	0.91670	0.91670	0.91670	0.91670	0.91670	0.91670	0.91670	0.91670	0.91670	0.91670	
7	Jurisdictional Energy Recoverable Costs (A)	1,305,066	1,130,243	1,232,181	1,110,838	1,104,267	1,326,222	1,227,397	1,148,823	1,057,467	885,159	813,172	969,368	13,310,203
8	Jurisdictional Demand Recoverable Costs - Transm (B)	43,690	41,895	278,709	224,256	164,788	219,703	50,347	140,162	161,096	188,866	133,019	176,241	1,822,772
	Jurisdictional Demand Recoverable Costs - Distrib (B)	1,526,119	1,663,383	1,931,512	2,324,784	2,575,845	1,966,893	2,313,302	2,390,726	1,298,429	1,800,170	1,274,160	1,695,581	22,760,904
	Jurisdictional Demand Recoverable Costs - Prod-Base (B)	11,992	0	12,309	11,991	0	782,402	782,076	782,076	782,076	0	0	0	3,164,922
	Jurisdictional Demand Recoverable Costs - Prod-Intm (B)	23,849	72,752	11,511	20,974	29,170	12,894	26,417	15,883	46,413	19,394	14,615	175,651	469,523
	Jurisdictional Demand Recoverable Costs - Prod-Peaking (B)	0	0	327,303	0	0	0	0	0	0	1,352	1,437	0	330,092
	Jurisdictional Demand Recoverable Costs - A&G	0	0	0	0	0	0	0	0	0	0	0	32,639	32,639
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$2,910,716	$2,908,273	$3,793,525	$3,692,843	$3,874,070	$4,308,114	$4,399,539	$4,477,670	$3,345,481	$2,894,941	$2,236,403	$3,049,480	$41,891,055

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

Form 42 6A

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2008 through December 2008

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				
	3.1 Pipeline Integrity Management - Bartow/Anclote Pipeline-Intermediate	$516,906	$521,581	($4,675)	-1%
	4.x Above Ground Tank Secondary Containment	781,112	798,905	(17,793)	-2%
	5 SO2/NOx Emissions Allowances	9,664,191	9,616,405	47,786	0%
	7.x CAIR/CAMR	2,106,508	2,094,513	11,995	1%
	9 Sea Turtle - Coastal Street Lighting -Distribution	1,586	2,398	(812)	-34%
	10.x Underground Storage Tanks-Base	41,499	41,499	0	0%
	11 Modular Cooling Towers - Base	192,713	192,713	0	0%
2	Total Capital Investment Activities - Recoverable Costs	**13,304,515**	**13,268,014**	**$36,501**	0%
3	Recoverable Costs Allocated to Energy	9,664,191	9,616,405	$47,786	0%
4	Recoverable Costs Allocated to Demand	$3,640,324	$3,651,609	($11,285)	0%

Notes:
Column (1) is the End of Period Totals on Form 42-7A
Column (2) = Estimated actual
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2008 through December 2008

Form 42-7A

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line	Description	Actual January 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	End of Period Total
1	Description of Investment Projects (A)													
	3.1 Pipeline Integrity Management - Bartow/Anclote Pipeline-Intermediate	$35,507	$35,432	$35,356	$35,521	$88,845	$37,302	$37,680	$39,038	$40,513	$41,555	$42,815	$47,342	$516,906
	4.1 Above Ground Tank Secondary Containment - Peaking	62,325	63,919	(128,152)	61,942	64,222	68,957	72,297	74,940	79,678	84,115	86,827	91,488	682,558
	4.2 Above Ground Tank Secondary Containment - Base	440	438	437	436	434	433	432	431	430	8,850	17,275	22,990	53,026
	4.3 Above Ground Tank Secondary Containment - Intermediate	5,101	5,083	5,065	5,047	5,028	5,011	(5,121)	4,080	4,072	4,063	4,054	4,045	45,528
	5 SO2/NOX Emissions Allowances - Energy	513,506	745,789	787,863	805,444	828,812	861,783	883,746	870,189	857,554	846,391	836,616	826,498	9,664,191
	7.1 CAIR/CAMR Anclote- Intermediate	706	706	706	706	706	706	706	706	706	706	706	354	8,120
	7.2 CAIR CT's - Peaking	27,094	28,453	28,497	28,502	13,374	26,129	26,094	25,942	25,903	25,859	25,820	25,780	307,447
	7.3 CAMR Crystal River - Base	410	590	866	1,031	1,240	1,502	1,615	1,918	2,231	2,246	2,686	3,144	19,479
	7.4 CAIR/CAMR Crystal River AFUDC - Base	0	0	0	0	118,130	223,170	225,998	228,046	231,693	233,432	234,190	276,803	1,771,462
	9 Sea Turtle - Coastal Street Lighting -Distribution	106	106	106	109	110	110	156	156	157	157	157	156	1,586
	10.1 Underground Storage Tanks-Base	2,434	2,429	2,424	2,418	2,414	2,409	2,404	2,398	2,393	2,389	2,383	2,378	28,873
	10.2 Underground Storage Tanks-Intermediate	1,064	1,062	1,060	1,058	1,056	1,053	1,051	1,049	1,046	1,044	1,043	1,040	12,626
	11 Modular Cooling Towers - Base	15,981	15,860	15,738	15,616	15,493	15,371	20,490	15,876	15,755	15,633	15,511	15,389	192,713
2	Total Investment Projects - Recoverable Costs	664,674	899,867	749,966	957,830	1,139,864	1,243,936	1,267,548	1,264,769	1,262,131	1,266,440	1,270,083	1,317,407	**13,304,515**
3	Recoverable Costs Allocated to Energy	513,506	745,789	787,863	805,444	828,812	861,783	883,746	870,189	857,554	846,391	836,616	826,498	9,664,191
	Recoverable Costs Allocated to Demand	106	106	106	109	110	110	156	156	157	157	157	156	1,586
4	Recoverable Costs Allocated to Demand - Production - Base	19,265	19,317	19,465	19,501	137,711	242,885	250,939	248,669	252,502	262,550	272,045	320,704	2,065,553
	Recoverable Costs Allocated to Demand - Production - Intermediate	42,378	42,283	42,187	42,332	95,635	44,072	34,316	44,873	46,337	47,368	48,618	52,781	583,180
	Recoverable Costs Allocated to Demand - Production - Peaking	89,419	92,372	(99,655)	90,444	77,596	95,086	98,391	100,882	105,581	109,974	112,647	117,268	990,005
5	Retail Energy Jurisdictional Factor	0.96490	0.96670	0.96840	0.96830	0.94630	0.95240	0.94850	0.95230	0.95630	0.94960	0.96240	0.96690	
	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)	495,482	720,954	762,967	779,911	784,305	820,762	838,233	828,681	820,079	803,733	805,159	799,141	9,259,407
	Jurisdictional Demand Recoverable Costs (B)	106	106	106	109	110	110	155	155	156	156	156	155	1,580
8	Jurisdictional Demand Recoverable Costs - Production - Base (C)	18,062	18,110	18,249	18,283	129,108	227,712	235,263	233,135	236,728	246,149	255,050	300,670	1,936,518
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	33,498	33,423	33,347	33,462	75,596	34,837	27,125	35,470	36,628	37,443	38,431	41,721	460,980
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	79,564	82,192	(88,672)	80,476	69,044	84,607	87,547	89,764	93,945	97,854	100,232	104,344	880,897
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$626,711	$854,785	$725,996	$912,241	$1,058,162	$1,168,027	$1,188,324	$1,187,205	$1,187,536	$1,185,334	$1,199,029	$1,246,031	$12,539,382

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 2008 through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: PIPELINE INTEGRITY MANAGEMENT - Bartow/Anclote Pipeline (Project 3.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$43,664	$0	$28,993	$57,985	$207,093	$79,338	$128,313	$119,218	$296,008	$960,613
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	983,298	
	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	3,657,886	
3	Less: Accumulated Depreciation		(254,167)	(261,009)	(267,852)	(274,694)	(281,537)	(354,101)	(363,210)	(372,319)	(381,428)	(390,537)	(399,646)	(408,755)	(419,544)	
4	CWIP - Non-Interest Bearing		22,685	22,685	22,685	22,685	66,349	66,349	95,342	153,327	360,420	439,758	568,072	687,290	0	
5	Net Investment (Lines 2 + 3 + 4)		$2,443,106	2,436,264	2,429,421	2,422,579	2,459,401	2,386,837	2,406,721	2,455,597	2,653,580	2,723,810	2,843,014	2,953,123	3,238,343	
6	Average Net Investment			2,439,685	2,432,843	2,426,000	2,440,990	2,423,122	2,396,779	2,431,158	2,554,588	2,688,695	2,783,412	2,898,068	3,095,733	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		22,689	22,625	22,562	22,701	22,535	22,291	22,610	23,758	25,005	25,885	26,952	28,790	$288,403
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		4,147	4,136	4,124	4,150	4,119	4,074	4,133	4,343	4,571	4,733	4,926	5,263	52,719
	c. Other (C)			0	0	0	0	(12,208)	0	0	0	0	0	0	0	(12,208)
8	Investment Expenses															
	a. Depreciation (D)			6,842	6,842	6,842	6,842	9,109	9,109	9,109	9,109	9,109	9,109	9,109	10,789	101,920
	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 (E)			1,828	1,828	1,828	1,828	1,828	1,828	1,828	1,828	1,828	1,828	1,828	2,500	22,608
	e. Other			0	0	0	0	63,462	0	0	0	0	0	0	0	63,462
9	Total System Recoverable Expenses (Lines 7 + 8)			35,507	35,432	35,356	35,521	88,845	37,302	37,680	39,038	40,513	41,555	42,815	47,342	516,906
	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			35,507	35,432	35,356	35,521	88,845	37,302	37,680	39,038	40,513	41,555	42,815	47,342	516,906
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 (F)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (G)			28,067	28,008	27,948	28,078	70,228	29,486	29,785	30,858	32,024	32,848	33,844	37,422	408,596
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$28,067	$28,008	$27,948	$28,078	$70,228	$29,486	$29,785	$30,858	$32,024	$32,848	$33,844	$37,422	$408,596

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) The credit in May is due to the true-up of depreciation rates which affected the return on average net investment for 2008.
(D) Depreciation calculated in Pipeline Integrity Management section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(E) Lines 2 x 89% @ .008313 x 1/12 + 11%@ .007299 x 1/12. Ratio from Property Tax Administration Department, based on plant allocation reported and 2007 Effective Tax Rate on original cost.
(F) Line 9a x Line 10
(G) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2008 through 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	Actual January 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	End of Period Total
1	Investments															
	a. Expenditures/Additions			($65,198)	$304,187	$44,654	$39,638	$396,364	$486,094	$135,334	$352,941	$241,037	$438,887	$91,224	$672,140	$3,137,300
	b. Clearings to Plant			363,266	(2,767)	(2)	0	0	0	428	13,519	1,042,889	10,428	(28,240)	343,275	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	(367,843)	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$3,525,178	3,888,444	3,885,677	3,885,675	3,885,675	3,885,675	3,885,675	3,886,102	3,899,621	4,942,510	4,952,938	4,924,698	5,267,973	
3	Less: Accumulated Depreciation		(141,321)	(151,700)	(162,478)	(180,096)	(190,874)	(201,652)	(212,430)	(216,369)	(227,178)	(238,803)	(251,251)	(263,654)	(276,408)	
4	CWIP - Non-Interest Bearing		1,131,378	702,913	1,009,867	686,680	726,319	1,122,683	1,608,776	1,743,682	2,083,104	1,281,252	1,709,712	1,829,175	2,158,040	
5	Net Investment (Lines 2 + 3 + 4)		$4,515,235	4,439,657	4,733,066	4,392,259	4,421,119	4,806,705	5,282,021	5,413,415	5,755,547	5,984,960	6,411,399	6,490,220	7,149,605	
6	Average Net Investment			4,477,446	4,586,361	4,378,741	4,406,689	4,613,912	5,044,363	5,347,717	5,584,480	5,870,253	6,198,178	6,450,808	6,819,912	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		41,640	42,653	40,721	40,983	42,909	46,913	49,735	51,937	54,593	57,642	59,993	63,425	$593,144
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		7,613	7,797	7,443	7,490	7,844	8,575	9,092	9,494	9,980	10,537	10,964	11,594	108,423
	c. Other (A)			0	0	(189,785)	0	0	0	0	0	0	0	0	0	(189,785)
8	Investment Expenses															
	a. Depreciation (C)			10,379	10,778	10,778	10,778	10,778	10,778	10,779	10,809	11,625	12,448	12,403	12,754	135,087
	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 (D)			2,693	2,691	2,691	2,691	2,691	2,691	2,691	2,700	3,480	3,488	3,467	3,715	35,689
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			62,325	63,919	(128,152)	61,942	64,222	68,957	72,297	74,940	79,678	84,115	86,827	91,488	682,557
	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			62,325	63,919	(128,152)	61,942	64,222	68,957	72,297	74,940	79,678	84,115	86,827	91,488	682,557
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)			55,456	56,874	(114,028)	55,115	57,144	61,357	64,329	66,681	70,897	74,845	77,258	81,405	607,333
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$55,456	$56,874	($114,028)	$55,115	$57,144	$61,357	$64,329	$66,681	$70,897	$74,845	$77,258	$81,405	$607,333

Notes:

(A) Credit in March due to impairment of portion of original work for tank at Turner plant that subsequently failed (Project 4.1a on Capital Program Detail file). The failed technology used was approved by the DEP at that time. This expense is recovered on Line 4 of 42-5A, and the return on investment portion is captured within the amount on Line 15 of 42-7A.
(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) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2007 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2008 through 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	Actual January 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,531,216	$757	$336,869	$1,868,842
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	1,868,841	
	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		$33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	1,901,933	
3	Less: Accumulated Depreciation		(5,883)	(5,994)	(6,105)	(6,216)	(6,327)	(6,438)	(6,549)	(6,660)	(6,771)	(6,882)	(6,993)	(7,104)	(9,419)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	1,531,216	1,531,973	0	
5	Net Investment (Lines 2+ 3 + 4)		$27,209	27,098	26,987	26,876	26,765	26,654	26,543	26,432	26,321	26,210	1,557,315	1,557,961	1,892,515	
6	Average Net Investment			27,153	27,042	26,931	26,820	26,709	26,598	26,487	26,376	26,265	791,762	1,557,637	1,725,237	0
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		253	251	250	249	248	247	246	245	244	7,363	14,486	16,045	40,127
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		46	46	46	46	45	45	45	45	45	1,346	2,648	2,933	7,336
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			111	111	111	111	111	111	111	111	111	111	111	2,315	3,536
	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)			30	30	30	30	30	30	30	30	30	30	30	1,697	2,027
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			440	438	437	436	434	433	432	431	430	8,850	17,275	22,990	53,026
	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			440	438	437	436	434	433	432	431	430	8,850	17,275	22,990	53,026
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)			413	411	410	409	407	406	405	404	403	8,297	16,196	21,554	49,713
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$413	$411	$410	$409	$407	$406	$405	$404	$403	$8,297	$16,196	$21,554	$49,713

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) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2007 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2008 through 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	Actual January 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 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		$290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	
3	Less: Accumulated Depreciation		(5,609)	(7,240)	(8,871)	(10,502)	(12,133)	(13,764)	(15,395)	(8,482)	(9,290)	(10,098)	(10,906)	(11,714)	(12,522)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+ 3 + 4)		$284,689	283,058	281,427	279,796	278,165	276,534	274,903	281,816	281,008	280,200	279,392	278,584	277,776	
6	Average Net Investment			283,873	282,242	280,611	278,980	277,349	275,718	278,359	281,412	280,604	279,796	278,988	278,180	0
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		2,640	2,625	2,610	2,595	2,579	2,564	2,589	2,617	2,610	2,602	2,595	2,587	31,213
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		483	480	477	474	471	469	473	478	477	476	474	473	5,705
	c. Other			0	0	0	0	0	0	214	0	0	0	0	0	214
8	Investment Expenses															
	a. Depreciation (C)			1,631	1,631	1,631	1,631	1,631	1,631	808	808	808	808	808	808	14,634
	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)			347	347	347	347	347	347	177	177	177	177	177	177	3,144
	e. Other			0	0	0	0	0	0	(9,382)	0	0	0	0	0	(9,382)
9	Total System Recoverable Expenses (Lines 7 + 8)			5,101	5,083	5,065	5,047	5,028	5,011	(5,121)	4,080	4,072	4,063	4,054	4,045	45,528
	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			5,101	5,083	5,065	5,047	5,028	5,011	(5,121)	4,080	4,072	4,063	4,054	4,045	45,528
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)			4,032	4,018	4,004	3,989	3,974	3,961	(4,048)	3,225	3,219	3,212	3,205	3,197	35,988
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$4,032	$4,018	$4,004	$3,989	$3,974	$3,961	($4,048)	$3,225	$3,219	$3,212	$3,205	$3,197	$35,988

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) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2007 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2008 through December 2008

Schedule of Amortization and Return
Deferred Gain on Sales of Emissions Allowances (Project 5)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual January 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	End of Period Total
1	Working Capital Dr (Cr)															
	a. 1581001 SO_2 Emission Allowance Inventory		$2,905,441	$24,564,484	$23,379,390	$22,091,084	$20,927,963	$19,465,163	$18,000,751	$16,634,804	$15,356,530	$14,178,833	$13,174,788	$12,257,938	$11,191,196	$11,191,196
	b. 25401FL Auctioned SO_2 Allowance		(2,019,940)	(2,004,023)	(1,988,106)	(1,972,189)	(1,956,272)	(2,566,605)	(2,494,697)	(2,422,790)	(2,350,883)	(2,278,975)	(2,207,068)	(2,135,161)	(2,063,254)	(2,063,254)
	c. 1581002 NOX Emission Allowance Inventory		28,663,433	41,255,433	50,390,808	51,346,838	56,006,838	58,816,088	65,467,108	65,495,858	65,502,545	65,510,820	65,510,820	65,510,820	65,510,820	65,510,820
	d. 1581003 Nox Emissions Allowance Reserve		0	0	0	0	0	0	0	0	0	0	0	0	0	
2	Total Working Capital		$29,548,933	63,815,893	71,782,092	71,465,733	74,978,528	75,714,646	80,973,162	79,707,871	78,508,192	77,410,678	76,478,539	75,633,597	74,638,763	74,638,763
3	Average Net Investment			46,682,413	67,798,992	71,623,912	73,222,131	75,346,587	78,343,904	80,340,516	79,108,032	77,959,435	76,944,609	76,056,068	75,136,180	
4	Return on Average Net Working Capital Balance															
	a. Equity Component Grossed Up For Taxes (A)	11.16%		434,146	630,531	666,102	680,966	700,723	728,598	747,167	735,705	725,023	715,585	707,321	698,766	$8,170,633
	b. Debt Component (Line 3 x 2.04% x 1/12)	2.04%		79,360	115,258	121,761	124,478	128,089	133,185	136,579	134,484	132,531	130,806	129,295	127,732	1,493,558
5	Total Return Component (B)			513,506	745,789	787,863	805,444	828,812	861,783	883,746	870,189	857,554	846,391	836,616	826,498	9,664,191
6	Expense Dr (Cr)															
	a. 5090001 SO_2 allowance expense			1,368,457	1,185,094	1,288,306	1,163,121	1,462,800	1,464,412	1,365,948	1,278,274	1,177,697	1,004,046	916,849	1,066,742	14,741,745
	b. 4074004 Amortization Expense			($15,917)	($15,917)	($15,917)	($15,917)	($295,869)	($71,907)	($71,907)	($71,907)	($71,907)	($71,907)	($71,907)	($71,907)	($862,888)
	c. 5090003 , Nox Allowance Expense			$0	$0	$0	$0	$0	$0	$0	$0	0	$0	$0	$0	
7	Net Expense (C)			1,352,540	1,169,177	1,272,389	1,147,204	1,166,931	1,392,505	1,294,040	1,206,366	1,105,790	932,138	844,942	994,835	13,878,857
8	Total System Recoverable Expenses (Lines 5 + 7)			1,866,046	1,914,966	2,060,252	1,952,648	1,995,743	2,254,288	2,177,786	2,076,555	1,963,344	1,778,529	1,681,558	1,821,333	23,543,048
	a. Recoverable costs allocated to Energy			1,866,046	1,914,966	2,060,252	1,952,648	1,995,743	2,254,288	2,177,786	2,076,555	1,963,344	1,778,529	1,681,558	1,821,333	23,543,048
	b. Recoverable costs allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor			0.96490	0.96670	0.96840	0.96830	0.94630	0.95240	0.94850	0.95230	0.95630	0.94960	0.96240	0.96690	
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)			1,800,548	1,851,197	1,995,148	1,890,749	1,888,572	2,146,984	2,065,630	1,977,504	1,877,546	1,688,891	1,618,331	1,761,046	22,562,147
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)			$ 1,800,548	$ 1,851,197	$ 1,995,148	$ 1,890,749	$ 1,888,572	$ 2,146,984	$ 2,065,630	$ 1,977,504	$ 1,877,546	$ 1,688,891	$ 1,618,331	$ 1,761,046	$ 22,562,147

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 2008 through 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	Actual January 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$7	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($64,200)	($64,193)
	b. Clearings to Plant			0	0	0	0	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		64,192	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	(1)	
5	Net Investment (Lines 2 + 3 + 4)		$64,192	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	(1)	
6	Average Net Investment			64,195	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	64,198	32,098	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		597	597	597	597	597	597	597	597	597	597	597	299	$6,866
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		109	109	109	109	109	109	109	109	109	109	109	55	1,254
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
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)	0.007299		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)			706	706	706	706	706	706	706	706	706	706	706	354	8,120
	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			706	706	706	706	706	706	706	706	706	706	706	354	8,120
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)			558	558	558	558	558	558	558	558	558	558	558	280	6,419
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$558	$558	$558	$558	$558	$558	$558	$558	$558	$558	$558	$280	$6,419

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 2007 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2008 through 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	Actual January 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$23,317	$11,748	$5,189	$4,727	$20,457	$26,428	($20,026)	$0	$0	$0	$0	$0	$71,841
	b. Clearings to Plant			705,515	11,748	5,189	4,727	20,457	26,428	(20,026)	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		$1,180,361	1,885,876	1,897,624	1,902,813	1,907,540	1,927,997	1,954,426	1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	
3	Less: Accumulated Depreciation		(5,914)	(11,174)	(17,656)	(24,156)	(30,672)	(21,562)	(25,234)	(28,889)	(32,544)	(36,199)	(39,854)	(43,509)	(47,164)	
4	CWIP - Non-Interest Bearing		682,200	2	2	2	2	1	1	1	1	1	1	1	1	
5	Net Investment (Lines 2 + 3 + 4)		$1,856,647	1,874,704	1,879,970	1,878,659	1,876,870	1,906,437	1,929,193	1,905,513	1,901,858	1,898,203	1,894,548	1,890,893	1,887,238	
6	Average Net Investment			1,865,675	1,877,337	1,879,314	1,877,765	1,891,653	1,917,816	1,917,354	1,903,686	1,900,031	1,896,376	1,892,721	1,889,066	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		17,351	17,460	17,477	17,465	17,874	17,837	17,832	17,704	17,671	17,635	17,601	17,569	$211,476
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		3,172	3,191	3,195	3,193	3,268	3,260	3,261	3,237	3,231	3,223	3,218	3,210	38,659
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			5,260	6,482	6,500	6,516	(9,110)	3,672	3,655	3,655	3,655	3,655	3,655	3,655	41,250
	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)			1,311	1,320	1,325	1,328	1,342	1,360	1,346	1,346	1,346	1,346	1,346	1,346	16,062
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			27,094	28,453	28,497	28,502	13,374	26,129	26,094	25,942	25,903	25,859	25,820	25,780	307,447
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			27,094	28,453	28,497	28,502	13,374	26,129	26,094	25,942	25,903	25,859	25,820	25,780	307,447
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Peaking)			0.88979	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)			24,108	25,317	25,356	25,361	11,900	23,249	23,218	23,083	23,048	23,009	22,974	22,939	273,563
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$24,108	$25,317	$25,356	$25,361	$11,900	$23,249	$23,218	$23,083	$23,048	$23,009	$22,974	$22,939	$273,563

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) Depreciation calculated in CAIR CTs section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Property tax calculated in CAIR CTs section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2007 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2008 through December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: CAMR - Crystal River - Base (Project 7.3 - Continuous Mercury Monitoring Systems)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$2,974	$29,737	$20,357	$9,793	$28,042	$19,736	$748	$54,383	$2,466	$373	$79,537	$3,610	$251,755
	b. Clearings to Plant			0	0	0	0	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		35,814	38,788	68,525	88,881	98,675	126,717	146,453	147,201	201,584	204,050	204,422	283,959	287,569	
5	Net Investment (Lines 2 + 3 + 4)		$35,814	38,788	68,525	88,881	98,675	126,717	146,453	147,201	201,584	204,050	204,422	283,959	287,569	
6	Average Net Investment			37,301	53,656	78,703	93,778	112,696	136,585	146,827	174,393	202,817	204,236	244,191	285,764	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		347	499	732	872	1,048	1,270	1,365	1,622	1,886	1,899	2,271	2,658	$16,469
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		63	91	134	159	192	232	250	296	345	347	415	486	3,010
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
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)	0.010707		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)			410	590	866	1,031	1,240	1,502	1,615	1,918	2,231	2,246	2,686	3,144	19,479
	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			410	590	866	1,031	1,240	1,502	1,615	1,918	2,231	2,246	2,686	3,144	19,479
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)			384	553	812	967	1,163	1,408	1,514	1,798	2,092	2,106	2,518	2,948	18,262
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$384	$553	$812	$967	$1,163	$1,408	$1,514	$1,798	$2,092	$2,106	$2,518	$2,948	$18,262

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 2007 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2008 through 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	Actual January 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$56,759,253	$53,940,373	$45,795,073	$49,541,474	$51,758,776	$44,201,549	$40,741,834	$38,425,935	$41,038,265	$33,863,625	$35,647,223	$32,345,629	$524,059,008
	b. Clearings to Plant			0	0	0	0	15,150,677	101,267	298,338	67,809	408,520	(665)	136,729	5,599,409	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)	8.848%		2,091,783	2,591,334	3,263,937	3,348,228	3,707,018	3,977,574	4,313,612	4,703,698	4,964,269	836,365	4,820,548	5,095,418	43,713,783
2	Plant-in-Service/Depreciation Base		$0	0	0	0	0	15,150,677	15,251,944	15,550,281	15,618,090	16,026,610	16,025,945	16,162,674	21,762,083	
3	Less: Accumulated Depreciation		0	0	0	0	0	(21,401)	(64,488)	(108,418)	(152,539)	(197,814)	(243,087)	(288,747)	(341,009)	
4	CWIP - AFUDC-Interest Bearing		328,850,158	387,701,194	444,232,901	493,291,911	546,181,614	586,496,730	634,574,587	679,331,694	722,393,518	767,987,532	802,688,187	843,019,229	874,860,866	567,772,791
5	Net Investment (Lines 2 + 3 + 4)		$328,850,158	387,701,194	444,232,901	493,291,911	546,181,614	601,626,007	649,762,043	694,773,558	737,859,070	783,816,328	818,471,046	858,893,156	896,281,941	
6	Average Net Investment			358,275,676	415,967,047	468,762,406	519,736,762	573,903,810	625,694,025	672,267,800	716,316,314	760,837,699	801,143,687	838,682,101	877,587,548	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		0	0	0	0	70,351	140,747	142,200	143,719	145,519	146,991	147,201	173,422	1,110,150
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		0	0	0	0	12,860	25,728	25,994	26,271	26,600	26,869	26,908	31,701	202,931
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			0	0	0	0	21,401	43,087	43,930	44,121	45,275	45,273	45,660	52,263	334,407
	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	13,518	13,608	13,874	13,935	14,299	14,299	14,421	19,417	117,371
	e. Property Insurance							0	0	0	0	0	0	0	0	
	f. 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	118,130	223,170	225,998	228,046	231,693	233,432	234,190	276,803	1,771,462
	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	118,130	223,170	225,998	228,046	231,693	233,432	234,190	276,803	1,771,462
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	110,750	209,229	211,880	213,800	217,219	218,850	219,560	259,511	1,660,799
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$0	$0	$0	$0	$110,750	$209,229	$211,880	$213,800	$217,219	$218,850	$219,560	$259,511	$1,660,799

Notes:
(A) AFUDC calculation based on 2005 Rate Case Settlement in Dkt. 050078-EI.
(B) Return on equity and debt calculated only on assets placed in service which appear in CAIR Crystal River AFUDC section of Capital Program Detail file. Calculated on that schedule as Line 6 x rate x 1/12. Rate 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) Depreciation calculated only on assets placed inservice which appear in CAIR Crystal River AFUDC section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Property taxes calculated only on assets placed inervice which appear in CAIR Crystal River AFUDC section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2007 Effective Tax Rate on original cost.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2008 through 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	Actual January 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$351	$0	$0	$0	$0	$95	$0	$0	$0	$446
	b. Clearings to Plant		0	0	0	0	0	0	10,051	0	95	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	10,051	10,051	10,146	10,146	10,146	10,146	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	(38)	(76)	(115)	(154)	(193)	(232)	
4	CWIP - Non-Interest Bearing	9,700	9,700	9,700	9,700	10,051	10,051	10,051	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$9,700	9,700	9,700	9,700	10,051	10,051	10,051	10,013	9,975	10,031	9,992	9,953	9,914	
6	Average Net Investment		9,700	9,700	9,700	9,876	10,051	10,051	10,032	9,994	10,003	10,012	9,973	9,934	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		90	90	90	92	93	93	93	93	93	93	93	92	$1,105
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		16	16	16	17	17	17	17	17	17	17	17	17	201
	c. Other		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	38	38	39	39	39	39	232
	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) 0.009400		0	0	0	0	0	0	8	8	8	8	8	8	48
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		106	106	106	109	110	110	156	156	157	157	157	156	1,586
	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		106	106	106	109	110	110	156	156	157	157	157	156	1,586
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)		106	106	106	109	110	110	155	155	156	156	156	155	1,580
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$106	$106	$106	$109	$110	$110	$155	$155	$156	$156	$156	$155	$1,580

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 2007 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2008 through 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	Actual January 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 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)	(3,452)	(3,912)	(4,372)	(4,832)	(5,292)	(5,752)	(6,212)	(6,672)	(7,132)	(7,592)	(8,052)	(8,512)	
4	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	164,569	164,109	163,649	163,189	162,729	162,269	161,809	161,349	160,889	160,429	
6	Average Net Investment		165,719	165,259	164,799	164,339	163,879	163,419	162,959	162,499	162,039	161,579	161,119	160,659	
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
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation (C) 3.27%		460	460	460	460	460	460	460	460	460	460	460	460	5,520
	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) 0.010707		151	151	151	151	151	151	151	151	151	151	151	151	1,812
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,434	2,429	2,424	2,418	2,414	2,409	2,404	2,398	2,393	2,389	2,383	2,378	28,873
	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		2,434	2,429	2,424	2,418	2,414	2,409	2,404	2,398	2,393	2,389	2,383	2,378	28,873
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)		2,282	2,277	2,273	2,267	2,263	2,259	2,254	2,248	2,244	2,240	2,234	2,229	27,069
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$2,282	$2,277	$2,273	$2,267	$2,263	$2,259	$2,254	$2,248	$2,244	$2,240	$2,234	$2,229	$27,069

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 2007 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2008 through 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	Actual January 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 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	$76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	
	3 Less: Accumulated Depreciation	(2,321)	(2,523)	(2,725)	(2,927)	(3,129)	(3,331)	(3,533)	(3,735)	(3,937)	(4,139)	(4,341)	(4,543)	(4,745)	
	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)	$73,685	73,483	73,281	73,079	72,877	72,675	72,473	72,271	72,069	71,867	71,665	71,463	71,261	
	6 Average Net Investment		73,584	73,382	73,180	72,978	72,776	72,574	72,372	72,170	71,968	71,766	71,564	71,362	
	7 Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		684	682	681	679	677	675	673	671	669	667	666	664	$8,088
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		125	125	124	124	124	123	123	123	122	122	122	121	1,478
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	8 Investment Expenses														
	a. Depreciation (C) 3.19%		202	202	202	202	202	202	202	202	202	202	202	202	2,424
	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) 0.008313		53	53	53	53	53	53	53	53	53	53	53	53	636
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
	9 Total System Recoverable Expenses (Lines 7 + 8)		1,064	1,062	1,060	1,058	1,056	1,053	1,051	1,049	1,046	1,044	1,043	1,040	12,626
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		1,064	1,062	1,060	1,058	1,056	1,053	1,051	1,049	1,046	1,044	1,043	1,040	12,626
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)		841	839	838	836	835	832	831	829	827	825	824	822	9,980
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$841	$839	$838	$836	$835	$832	$831	$829	$827	$825	$824	$822	$9,980

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 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 2007 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2008 through 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	Actual January 08	Actual February 08	Actual March 08	Actual April 08	Actual May 08	Actual June 08	Actual July 08	Actual August 08	Actual September 08	Actual October 08	Actual November 08	Actual December 08	End of Period Total
1 Investments														
a. Expenditures/Additions		$0	$4	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4
b. Clearings to Plant		0	4	0	0	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	$665,137	665,137	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	
3 Less: Accumulated Depreciation	(191,115)	(202,201)	(213,287)	(224,373)	(235,459)	(246,545)	(257,631)	(268,717)	(279,803)	(290,889)	(301,975)	(313,061)	(324,147)	
4 CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)	$474,021	462,935	451,853	440,767	429,681	418,595	407,509	396,423	385,337	374,251	363,165	352,079	340,993	
6 Average Net Investment		468,478	457,394	446,310	435,224	424,138	413,052	401,966	390,880	379,794	368,708	357,622	346,536	
7 Return on Average Net Investment														
a. Equity Component Grossed Up For Taxes (B) 11.16%		4,357	4,254	4,151	4,048	3,944	3,841	3,738	3,635	3,532	3,429	3,326	3,223	$45,478
b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		796	778	759	740	721	702	683	664	646	627	608	589	8,313
c. Other (G)		(662)	(662)	(662)	(662)	(662)	(662)	3,972	0	0	0	0	0	0
8 Investment Expenses														
a. Depreciation (C) 20.00%		11,086	11,086	11,086	11,086	11,086	11,086	11,086	11,086	11,086	11,086	11,086	11,086	133,032
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) 0.010707		593	593	593	593	593	593	593	593	593	593	593	593	7,116
e. Other (G)		(189)	(189)	(189)	(189)	(189)	(189)	418	(102)	(102)	(102)	(102)	(102)	(1,225)
9 Total System Recoverable Expenses (Lines 7 + 8)		15,981	15,860	15,738	15,616	15,493	15,371	20,490	15,876	15,755	15,633	15,511	15,389	192,713
a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand		15,981	15,860	15,738	15,616	15,493	15,371	20,490	15,876	15,755	15,633	15,511	15,389	192,713
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)		14,983	14,869	14,755	14,640	14,525	14,411	19,210	14,884	14,771	14,656	14,542	14,428	180,674
14 Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$14,983	$14,869	$14,755	$14,640	$14,525	$14,411	$19,210	$14,884	$14,771	$14,656	$14,542	$14,428	$180,674

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 x rate x 1/12. Based on 2007 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11
(G) Beginning in July, this schedule only includes a credit for depreciation expense that is included in base rates for breakers that were replaced by upgraded breakers to compensate for increased load due to the Modular Cooling Towers.
It was determined that only a credit for depreciation expense is required per Order No. PSC-99-2513-FOF-EI so the return and property tax credits for January to June 2008 were reversed in July.

Form Appendix

EXHIBIT 2 (WG-2)

PROGRESS ENERGY FLORIDA, INC.
ENVIRONMENTAL COST RECOVERY
CAPITAL PROGRAM DETAIL

JANUARY 2008 - DECEMBER 2008

DOCKET NO. 090007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 21
COMPANY Progress Energy Florida, Inc.
WITNESS Will Garrett (WG-2)
DATE 11/02/09

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Deatil Support - January 2008 through December 2008
Pipline Intergrity Management (Project 3 Recap)

For Project: PIPELINE INTEGRITY MANAGEMENT - Alderman Road Fence (Project 3.1a)
(in Dollars)

Intermediate

Line Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual 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		$33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	
3 Less: Accumulated Depreciation		(3,409)	(3,496)	(3,583)	(3,670)	(3,757)	(3,844)	(3,931)	(4,018)	(4,105)	(4,192)	(4,279)	(4,366)	(4,453)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$30,544	30,457	30,370	30,283	30,196	30,109	30,022	29,935	29,848	29,761	29,674	29,587	29,500	
6 Average Net Investment			30,500	30,413	30,326	30,239	30,152	30,065	29,978	29,891	29,804	29,717	29,630	29,543	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		284	283	282	281	280	280	279	278	277	276	276	275	$3,351
b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		52	52	52	51	51	51	51	51	51	51	50	50	613
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	3.07%		87	87	87	87	87	87	87	87	87	87	87	87	1,044
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	0.008201		23	23	23	23	23	23	23	23	23	23	23	23	276
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			446	445	444	442	441	441	440	439	438	437	436	435	5,284
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			446	445	444	442	441	441	440	439	438	437	436	435	5,284

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Leak Detection (Project 3.1b)
(in Dollars)

Intermediate

Line Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual 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		$2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	
3 Less: Accumulated Depreciation		(250,749)	(257,505)	(264,261)	(271,017)	(277,773)	(350,257)	(359,279)	(368,301)	(377,323)	(386,345)	(395,367)	(404,389)	(413,411)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$2,389,887	2,383,131	2,376,375	2,369,619	2,362,863	2,290,379	2,281,357	2,272,335	2,263,313	2,254,291	2,245,269	2,236,247	2,227,225	
6 Average Net Investment			2,386,509	2,379,753	2,372,997	2,366,241	2,326,621	2,285,868	2,276,846	2,267,824	2,258,802	2,249,780	2,240,758	2,231,736	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		22,193	22,130	22,067	22,005	21,638	21,259	21,175	21,091	21,007	20,923	20,839	20,755	$257,082
b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		4,057	4,046	4,034	4,023	3,955	3,886	3,871	3,855	3,840	3,825	3,809	3,794	46,995
c. Other			0	0	0	0	(12,208)	0	0	0	0	0	0	0	(12,208)
8 Investment Expenses															
a. Depreciation	4.10%		6,756	6,756	6,756	6,756	9,022	9,022	9,022	9,022	9,022	9,022	9,022	9,022	99,200
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	0.008201		1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	21,660
e. Other			0	0	0	0	63,462	0	0	0	0	0	0	0	63,462
9 Total System Recoverable Expenses (Lines 7 + 8)			34,811	34,737	34,662	34,589	87,674	35,972	35,873	35,773	35,674	35,575	35,475	35,376	476,191
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			34,811	34,737	34,662	34,589	87,674	35,972	35,873	35,773	35,674	35,575	35,475	35,376	476,191

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Controls Upgrade (Project 3.1c)
(in Dollars)

Intermediate

Line	Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$43,664	$0	$28,993	$57,965	$207,093	$79,338	$128,313	$119,218	$296,008	$960,613
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	983,298	
	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	983,298	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	(1,680)	
4	CWIP - Non-Interest Bearing		22,685	22,685	22,685	22,685	66,349	66,349	95,342	153,327	360,420	439,758	568,071	687,290	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$22,685	22,685	22,685	22,685	66,349	66,349	95,342	153,327	360,420	439,758	568,071	687,290	981,618	
6	Average Net Investment			22,685	22,685	22,685	44,517	66,349	80,846	124,334	256,873	400,089	503,915	627,680	834,454	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		211	211	211	414	617	752	1,156	2,389	3,721	4,686	5,837	7,760	$27,965
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		39	39	39	76	113	137	211	437	680	857	1,067	1,419	5,114
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	4.10%		0	0	0	0	0	0	0	0	0	0	0	1,680	1,680
	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	0.008201		0	0	0	0	0	0	0	0	0	0	0	672	672
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			250	250	250	490	730	889	1,367	2,826	4,401	5,543	6,904	11,531	35,431
	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			250	250	250	490	730	889	1,367	2,826	4,401	5,543	6,904	11,531	35,431

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - TURNER CTs (Project 4.1a)
(in Dollars)

Peaking

Line Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1 Investments															
a. Expenditures/Additions			$0	$303,297	$35,483	$29,422	$41,640	$200,238	$428	$1,849	$122,650	$114,275	$2,018	$390,502	$1,241,800
b. Clearings to Plant			0	0	0	0	0	0	0	0	1,039,281	10,428	(28,525)	30,000	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	(367,843)	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		$0	0	0	0	0	0	0	0	0	1,039,281	1,049,708	1,021,183	1,051,183	
3 Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	(808)	(2,439)	(4,025)	(5,658)	
4 CWIP - Non-Interest Bearing		674,010	674,010	977,307	644,946	674,368	716,008	916,246	916,673	918,522	1,891	105,739	136,282	496,784	
5 Net Investment (Lines 2 + 3 + 4)		$674,010	674,010	977,307	644,946	674,368	716,008	916,246	916,673	918,522	1,040,364	1,153,009	1,153,440	1,542,310	
6 Average Net Investment			674,010	825,658	627,206	659,657	695,188	816,127	916,459	917,597	979,443	1,096,686	1,153,224	1,347,875	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		6,268	7,679	5,833	6,135	6,465	7,590	8,523	8,534	9,109	10,199	10,725	12,535	$99,595
b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		1,146	1,404	1,066	1,121	1,182	1,387	1,558	1,560	1,665	1,864	1,960	2,291	18,204
c. Other			0	0	(189,785)	0	0	0	0	0	0	0	0	0	(189,785)
8 Investment Expenses															
a. Depreciation	1.86%		0	0	0	0	0	0	0	0	808	1,631	1,586	1,633	5,658
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		0	0	0	0	0	0	0	0	777	785	764	786	3,112
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			7,414	9,083	(182,886)	7,256	7,647	8,977	10,081	10,094	12,359	14,479	15,035	17,245	(63,217)
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			7,414	9,083	(182,886)	7,256	7,647	8,977	10,081	10,094	12,359	14,479	15,035	17,245	(63,217)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BARTOW CTs (Project 4.1b)
(in Dollars)

Peaking

Line Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1 Investments															
a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,060	$3,283	$9,227	$15,570
b. Clearings to Plant			0	0	0	0	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)	(26,780)	(27,204)	(27,628)	(28,052)	(28,476)	(28,900)	(29,324)	(29,748)	(30,172)	(30,596)	
4 CWIP - Non-Interest Bearing		1,755	1,755	1,755	1,755	1,755	1,755	1,755	1,755	1,755	1,755	4,815	8,098	17,325	
5 Net Investment (Lines 2 + 3 + 4)		$129,945	129,521	129,097	128,673	128,249	127,825	127,401	126,977	126,553	126,129	128,765	131,624	140,427	
6 Average Net Investment			129,733	129,309	128,885	128,461	128,037	127,613	127,189	126,765	126,341	127,447	130,195	136,026	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		1,207	1,203	1,199	1,195	1,191	1,187	1,183	1,179	1,175	1,185	1,211	1,265	$14,380
b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		221	220	219	218	218	217	216	216	215	217	221	231	2,629
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	3.31%		424	424	424	424	424	424	424	424	424	424	424	424	5,088
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	0.008313		106	106	106	106	106	106	106	106	106	106	106	106	1,272
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			1,958	1,953	1,948	1,943	1,939	1,934	1,929	1,925	1,920	1,932	1,962	2,026	23,369
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			1,958	1,953	1,948	1,943	1,939	1,934	1,929	1,925	1,920	1,932	1,962	2,026	23,369

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-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual 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		$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)	(6,327)	(6,438)	(6,549)	(6,660)	(6,771)	(6,882)	(6,993)	(7,104)	(7,215)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$27,209	27,098	26,987	26,876	26,765	26,654	26,543	26,432	26,321	26,210	26,099	25,988	25,877	
6 Average Net Investment			27,153	27,042	26,931	26,820	26,709	26,598	26,487	26,376	26,265	26,154	26,043	25,932	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		253	251	250	249	248	247	246	245	244	243	242	241	$2,959
b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		46	46	46	46	45	45	45	45	45	44	44	44	541
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	4.03%		111	111	111	111	111	111	111	111	111	111	111	111	1,332
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	0.010707		30	30	30	30	30	30	30	30	30	30	30	30	360
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			440	438	437	436	434	433	432	431	430	428	427	426	5,192
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			440	438	437	436	434	433	432	431	430	428	427	426	5,192

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - INTERCESSION CITY CTs (Project 4.1c)
(in Dollars)

Peaking

Line Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-06	Actual Nov-08	Actual Dec-08	End of Period Total
1 Investments															
a. Expenditures/Additions			($2,804)	$37	($2)	$0	$0	$0	$0	$0	$0	$0	$0	$0	($2,769)
b. Clearings to Plant			(2,804)	37	(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. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		$1,664,433	1,661,629	1,661,666	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	
3 Less: Accumulated Depreciation		(63,467)	(68,161)	(72,855)	(84,389)	(89,083)	(93,777)	(96,471)	(96,325)	(101,019)	(105,713)	(110,407)	(115,101)	(119,795)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$1,600,966	1,593,468	1,588,811	1,577,275	1,572,581	1,567,887	1,563,193	1,565,339	1,560,645	1,555,951	1,551,257	1,546,563	1,541,869	
6 Average Net Investment			1,597,217	1,591,139	1,583,043	1,574,928	1,570,234	1,565,540	1,564,266	1,562,992	1,558,298	1,553,604	1,548,910	1,544,216	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		14,854	14,798	14,722	14,647	14,603	14,560	14,548	14,536	14,492	14,449	14,405	14,361	$174,975
b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		2,715	2,705	2,691	2,677	2,669	2,661	2,659	2,657	2,649	2,641	2,633	2,625	31,982
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	3.39%		4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	56,328
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	0.007614		1,054	1,054	1,054	1,054	1,054	1,054	1,054	1,054	1,054	1,054	1,054	1,054	12,648
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			23,317	23,251	23,161	23,072	23,020	22,969	22,955	22,941	22,889	22,838	22,786	22,734	275,933
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			23,317	23,251	23,161	23,072	23,020	22,969	22,955	22,941	22,889	22,838	22,786	22,734	275,933

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - AVON PARK CTs (Project 4.1d)
(in Dollars)

Peaking

Line	Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual 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)	(9,201)	(9,721)	(10,241)	(10,761)	(11,281)	(11,801)	(12,321)	(12,841)	(13,361)	(13,881)	(14,401)	(14,921)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$170,257	169,737	169,217	168,697	168,177	167,657	167,137	166,617	166,097	165,577	165,057	164,537	164,017	
6	Average Net Investment			169,997	169,477	168,957	168,437	167,917	167,397	166,877	166,357	165,837	165,317	164,797	164,277	
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	3,409
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.49%		520	520	520	520	520	520	520	520	520	520	520	520	6,240
	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	0.009194		137	137	137	137	137	137	137	137	137	137	137	137	1,644
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,527	2,521	2,515	2,509	2,504	2,499	2,493	2,487	2,481	2,475	2,470	2,464	29,945
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			2,527	2,521	2,515	2,509	2,504	2,499	2,493	2,487	2,481	2,475	2,470	2,464	29,945

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BAYBORO CTs (Project 4.1e)
(in Dollars)

Peaking

Line	Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			($85,614)	($2,804)	$0	$0	$0	$0	$428	$13,519	$3,608	$0	$285	($285)	($70,863)
	b. Clearings to Plant			365,936	(2,804)	0	0	0	0	428	13,519	3,608	0	285	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		$349,609	715,545	712,740	712,740	712,740	712,740	712,740	713,168	726,687	730,295	730,295	730,580	730,580	
3	Less: Accumulated Depreciation		(7,419)	(8,600)	(10,180)	(11,760)	(13,340)	(14,920)	(16,500)	(18,081)	(19,692)	(21,311)	(22,930)	(24,549)	(26,168)	
4	CWIP - Non-Interest Bearing		451,549	0	0	0	0	0	0	0	0	0	0	0	(285)	
5	Net Investment (Lines 2 + 3 + 4)		$793,740	706,945	702,561	700,981	699,401	697,821	696,241	695,087	706,995	708,984	707,365	706,031	704,127	
6	Average Net Investment			750,342	704,753	701,771	700,191	698,611	697,031	695,664	701,041	707,990	708,175	706,698	705,079	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		6,978	6,554	6,526	6,512	6,497	6,482	6,470	6,520	6,584	6,586	6,572	6,557	$78,838
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		1,276	1,198	1,193	1,190	1,188	1,185	1,183	1,192	1,204	1,204	1,201	1,199	14,413
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.66%		1,181	1,580	1,580	1,580	1,580	1,580	1,581	1,611	1,619	1,619	1,619	1,619	18,749
	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	0.008313		496	494	494	494	494	494	494	503	506	506	506	506	5,987
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			9,931	9,826	9,793	9,776	9,759	9,741	9,728	9,826	9,913	9,915	9,898	9,881	117,987
	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			9,931	9,826	9,793	9,776	9,759	9,741	9,728	9,826	9,913	9,915	9,898	9,881	117,987

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2008 through December 2008
Above Ground Tank Secondary Containment (Projects 4.1 - 4.3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - SUWANNEE CTs (Project 4.1f)
(in Dollars)

Peaking

Line Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1 Investments															
a. Expenditures/Additions			$135	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$135
b. Clearings to Plant			135	0	0	0	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		$1,037,064	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	
3 Less: Accumulated Depreciation		(17,976)	(20,742)	(23,508)	(26,274)	(29,040)	(31,806)	(34,572)	(37,338)	(40,104)	(42,870)	(45,636)	(48,402)	(51,168)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$1,019,088	1,016,457	1,013,691	1,010,925	1,008,159	1,005,393	1,002,627	999,861	997,095	994,329	991,563	988,797	986,031	
6 Average Net Investment			1,017,773	1,015,074	1,012,308	1,009,542	1,006,776	1,004,010	1,001,244	998,478	995,712	992,946	990,180	987,414	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		9,465	9,440	9,414	9,389	9,363	9,337	9,312	9,286	9,260	9,234	9,209	9,183	$111,892
b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		1,730	1,726	1,721	1,716	1,712	1,707	1,702	1,697	1,693	1,688	1,683	1,679	20,454
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	3.20%		2,766	2,766	2,766	2,766	2,766	2,766	2,766	2,766	2,766	2,766	2,766	2,766	33,192
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	0.008454		731	731	731	731	731	731	731	731	731	731	731	731	8,772
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			14,692	14,663	14,632	14,602	14,572	14,541	14,511	14,480	14,450	14,419	14,389	14,359	174,310
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			14,692	14,663	14,632	14,602	14,572	14,541	14,511	14,480	14,450	14,419	14,389	14,359	174,310

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - DeBARY CTs (Project 4.1g)
(in Dollars)

Peaking

Line Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1 Investments															
a. Expenditures/Additions			$23,085	$3,657	$9,173	$10,216	$354,724	$285,856	$134,479	$337,573	$114,779	$321,552	$85,638	$272,696	$1,953,428
b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	313,275	
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	313,275	
3 Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	(304)	
4 CWIP - Non-Interest Bearing		4,064	27,149	30,806	39,980	50,196	404,920	690,776	825,255	1,162,827	1,277,607	1,599,158	1,684,796	1,644,217	
5 Net Investment (Lines 2 + 3 + 4)		$4,064	27,149	30,806	39,980	50,196	404,920	690,776	825,255	1,162,827	1,277,607	1,599,158	1,684,796	1,957,188	
6 Average Net Investment			15,607	28,978	35,393	45,088	227,558	547,848	758,015	994,041	1,220,217	1,438,382	1,641,977	1,820,992	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		145	269	329	419	2,116	5,095	7,050	9,245	11,348	13,377	15,270	16,935	$81,598
b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		27	49	60	77	387	931	1,289	1,690	2,074	2,445	2,791	3,096	14,916
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	2.33%		0	0	0	0	0	0	0	0	0	0	0	304	304
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	0.008570		0	0	0	0	0	0	0	0	0	0	0	226	226
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			172	318	389	496	2,503	6,026	8,339	10,935	13,422	15,822	18,061	20,561	97,044
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			172	318	389	496	2,503	6,026	8,339	10,935	13,422	15,822	18,061	20,561	97,044

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - University of Florida (Project 4.1h)
(in Dollars)

Peaking

Line	Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual 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)	(19,064)	(19,858)	(20,652)	(21,446)	(22,240)	(23,034)	(23,828)	(24,622)	(25,416)	(26,210)	(27,004)	(27,798)	
4	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	120,782	119,988	119,194	118,400	117,606	116,812	116,018	115,224	114,430	113,636	
6	Average Net Investment			122,767	121,973	121,179	120,385	119,591	118,797	118,003	117,209	116,415	115,621	114,827	114,033	
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	1,061	$13,214
	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	2,416
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	6.74%		794	794	794	794	794	794	794	794	794	794	794	794	9,528
	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	0.014338		169	169	169	169	169	169	169	169	169	169	169	169	2,028
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,314	2,304	2,296	2,288	2,278	2,270	2,261	2,252	2,244	2,235	2,226	2,218	27,186
	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			2,314	2,304	2,296	2,288	2,278	2,270	2,261	2,252	2,244	2,235	2,226	2,218	27,186

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Anclote (Project 4.3)
(in Dollars)

Intermediate

Line	Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual 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		$290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	
3	Less: Accumulated Depreciation		($5,609)	(7,240)	(8,871)	(10,502)	(12,133)	(13,764)	(15,395)	(8,482)	(9,290)	(10,098)	(10,906)	(11,714)	(12,522)	
4	CWIP - Non-Interest Bearing		$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$284,689	283,058	281,427	279,796	278,165	276,534	274,903	281,816	281,008	280,200	279,392	278,584	277,776	
6	Average Net Investment			283,873	282,242	280,611	278,980	277,349	275,718	278,359	281,412	280,604	279,796	278,988	278,180	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		2,640	2,625	2,610	2,595	2,579	2,564	2,589	2,617	2,610	2,602	2,595	2,587	$31,213
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		483	480	477	474	471	469	473	478	477	476	474	473	5,705
	c. Other			0	0	0	0	0	0	214	0	0	0	0	0	214
8	Investment Expenses															
	a. Depreciation	3.34%		1,631	1,631	1,631	1,631	1,631	1,631	808	808	808	808	808	808	14,634
	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	0.007299		347	347	347	347	347	347	177	177	177	177	177	177	3,144
	e. Other			0	0	0	0	0	0	(9,382)	0	0	0	0	0	(9,382)
9	Total System Recoverable Expenses (Lines 7 + 8)			5,101	5,083	5,065	5,047	5,028	5,011	(5,121)	4,080	4,072	4,063	4,054	4,045	45,528
	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			5,101	5,083	5,065	5,047	5,028	5,011	(5,121)	4,080	4,072	4,063	4,054	4,045	45,528

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 4 & 5 (Project 4.2)
(in Dollars)

Base

Line	Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,531,216	$757	$336,869	$1,868,842
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	$1,868,841	
	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	1,868,841	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	(2,204)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	1,531,216	1,531,973	0	
5	Net Investment (Lines 2 + 3 + 4)		$0	0	0	0	0	0	0	0	0	0	1,531,216	1,531,973	1,866,638	
6	Average Net Investment			0	0	0	0	0	0	0	0	0	765,608	1,531,594	1,699,305	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		0	0	0	0	0	0	0	0	0	7,120	14,244	15,804	$37,168
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		0	0	0	0	0	0	0	0	0	1,302	2,604	2,889	6,795
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.83%		0	0	0	0	0	0	0	0	0	0	0	2,204	2,204
	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	0.010707		0	0	0	0	0	0	0	0	0	0	0	1,667	1,667
	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	8,422	16,848	22,564	47,834
	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	8,422	16,848	22,564	47,834

For Project: CAIR CTs - AVON PARK (Project 7.2a)
(In Dollars)

ALL Peaking

Line Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1 Investments															
a. Expenditures/Additions			($14,948)	$604	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	($14,343)
b. Clearings to Plant			(14,948)	604	0	0	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		$176,097	161,150	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	
3 Less: Accumulated Depreciation		(384)	(626)	(869)	(1,112)	(1,355)	(1,171)	(1,349)	(1,527)	(1,705)	(1,883)	(2,061)	(2,239)	(2,417)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$175,714	160,524	160,885	160,642	160,399	160,583	160,405	160,227	160,049	159,871	159,693	159,515	159,337	
6 Average Net Investment			168,119	160,705	160,764	160,521	160,491	160,494	160,316	160,138	159,960	159,782	159,604	159,426	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		1,564	1,495	1,495	1,493	1,503	1,493	1,491	1,489	1,488	1,486	1,484	1,483	$17,964
b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		286	273	273	273	275	273	273	272	272	272	271	271	3,284
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	1.32%		242	243	243	243	(184)	178	178	178	178	178	178	178	2,033
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	0.009194		123	124	124	124	124	124	124	124	124	124	124	124	1,487
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			2,215	2,135	2,135	2,133	1,718	2,068	2,066	2,063	2,062	2,060	2,057	2,056	24,768
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			2,215	2,135	2,135	2,133	1,718	2,068	2,066	2,063	2,062	2,060	2,057	2,056	24,768

For Project: CAIR CTs - BARTOW (Project 7.2b)
(In Dollars)

Line Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1 Investments															
a. Expenditures/Additions			$4,344	$4,096	$653	$266	$0	$0	$0	$0	$0	$0	$0	$0	$9,359
b. Clearings to Plant			4,344	4,096	653	266	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		$265,988	270,331	274,428	275,080	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	
3 Less: Accumulated Depreciation		(1,386)	(2,350)	(3,329)	(4,310)	(5,292)	(4,852)	(5,611)	(6,370)	(7,129)	(7,888)	(8,647)	(9,406)	(10,165)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$264,602	267,982	271,099	270,771	270,055	270,495	269,736	268,977	268,218	267,459	266,700	265,941	265,182	
6 Average Net Investment			266,292	269,541	270,935	270,413	270,275	270,116	269,357	268,598	267,839	267,080	266,321	265,562	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		2,477	2,507	2,520	2,515	2,544	2,512	2,505	2,498	2,491	2,484	2,477	2,470	$30,000
b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		453	458	461	460	465	459	458	457	455	454	453	451	5,484
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	3.31%		964	979	981	982	(440)	759	759	759	759	759	759	759	8,779
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	0.008313		187	190	191	191	191	191	191	191	191	191	191	191	2,287
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			4,081	4,134	4,153	4,148	2,760	3,921	3,913	3,905	3,896	3,888	3,880	3,871	46,550
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			4,081	4,134	4,153	4,148	2,760	3,921	3,913	3,905	3,896	3,888	3,880	3,871	46,550

For Project: CAIR CTs - BAYBORO (Project 7.2c)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1 Investments															
a. Expenditures/Additions			$403	$2,104	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,508
b. Clearings to Plant			403	2,104	0	0	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		$196,480	196,884	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	
3 Less: Accumulated Depreciation		(715)	(1,214)	(1,718)	(2,222)	(2,726)	(2,795)	(3,231)	(3,667)	(4,103)	(4,539)	(4,975)	(5,411)	(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)		$196,766	195,670	197,270	196,766	196,262	196,193	195,757	195,321	194,885	194,449	194,013	193,577	193,141	
6 Average Net Investment			195,718	196,470	197,018	196,514	196,228	195,975	195,539	195,103	194,667	194,231	193,795	193,359	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		1,820	1,827	1,832	1,828	1,835	1,823	1,819	1,814	1,810	1,806	1,802	1,798	$21,814
b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		333	334	335	334	336	333	332	332	331	330	329	329	3,988
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	2.63%		499	504	504	504	69	436	436	436	436	436	436	436	5,132
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	0.008313		136	138	138	138	138	138	138	138	138	138	138	138	1,654
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			2,788	2,803	2,809	2,804	2,378	2,730	2,725	2,720	2,715	2,710	2,705	2,701	32,588
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			2,788	2,803	2,809	2,804	2,378	2,730	2,725	2,720	2,715	2,710	2,705	2,701	32,588

For Project: CAIR CTs - DeBARY (Project 7.2d)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1 Investments															
a. Expenditures/Additions			$897	$319	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,217
b. Clearings to Plant			897	319	0	0	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		$86,450	87,348	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	
3 Less: Accumulated Depreciation		(373)	(590)	(808)	(1,026)	(1,244)	(1,663)	(1,911)	(2,159)	(2,407)	(2,655)	(2,903)	(3,151)	(3,399)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$86,078	86,758	86,860	86,642	86,424	86,005	85,757	85,509	85,261	85,013	84,765	84,517	84,269	
6 Average Net Investment			86,418	86,809	86,751	86,533	86,214	85,881	85,633	85,385	85,137	84,889	84,641	84,393	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		804	807	807	805	797	799	796	794	792	789	787	785	$9,562
b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		147	148	147	147	145	146	146	145	145	144	144	143	1,747
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	3.39%		217	218	218	218	419	248	248	248	248	248	248	248	3,026
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	0.008670		63	63	63	63	63	63	63	63	63	63	63	63	756
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			1,231	1,236	1,235	1,233	1,424	1,256	1,253	1,250	1,248	1,244	1,242	1,239	15,091
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			1,231	1,236	1,235	1,233	1,424	1,256	1,253	1,250	1,248	1,244	1,242	1,239	15,091

For Project: CAIR CTs - HIGGINS (Project 7.2e)
(In Dollars)

Line Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1 Investments															
a. Expenditures/Additions			$4,593	$925	$384	$2,371	$20,457	$26,428	($20,026)	$0	$0	$0	$0	$0	$35,133
b. Clearings to Plant			314,950	925	384	2,371	20,457	26,428	(20,026)	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	314,950	315,875	316,259	318,630	339,087	365,516	345,490	345,490	345,490	345,490	345,490	345,490	
3 Less: Accumulated Depreciation		0	(512)	(1,539)	(2,567)	(3,603)	(1,208)	(1,513)	(1,801)	(2,089)	(2,377)	(2,665)	(2,953)	(3,241)	
4 CWIP - Non-Interest Bearing		310,357	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$310,357	314,438	314,336	313,692	315,027	337,879	364,003	343,689	343,401	343,113	342,825	342,537	342,249	
6 Average Net Investment			312,397	314,387	314,014	314,360	326,453	350,941	353,846	343,545	343,257	342,969	342,681	342,393	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		2,905	2,924	2,920	2,924	3,080	3,264	3,291	3,195	3,192	3,190	3,187	3,184	$37,256
b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		531	534	534	534	563	597	602	584	584	583	583	582	6,811
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	1.00%		512	1,027	1,028	1,036	(2,395)	305	288	288	288	288	288	288	3,241
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	0.008313		218	219	219	221	235	253	239	239	239	239	239	239	2,799
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			4,166	4,704	4,701	4,715	1,483	4,419	4,420	4,306	4,303	4,300	4,297	4,293	50,107
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			4,166	4,704	4,701	4,715	1,483	4,419	4,420	4,306	4,303	4,300	4,297	4,293	50,107

For Project: CAIR CTs - INTERCESSION CITY (Project 7.2f)
(In Dollars)

Line Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1 Investments															
a. Expenditures/Additions			$21,336	$319	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$21,656
b. Clearings to Plant			21,336	319	0	0	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		$327,928	349,264	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	
3 Less: Accumulated Depreciation		(2,291)	(3,921)	(5,552)	(7,183)	(8,814)	(4,905)	(5,671)	(6,437)	(7,203)	(7,969)	(8,735)	(9,501)	(10,267)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$325,637	345,343	344,032	342,401	340,770	344,679	343,913	343,147	342,381	341,615	340,849	340,083	339,317	
6 Average Net Investment			335,490	344,687	343,216	341,585	342,724	344,296	343,530	342,764	341,998	341,232	340,466	339,700	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		3,120	3,206	3,192	3,177	3,307	3,202	3,195	3,188	3,181	3,173	3,166	3,159	$38,266
b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		570	586	583	581	605	585	584	583	581	580	579	577	6,994
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	2.63%		1,630	1,631	1,631	1,631	(3,909)	766	766	766	766	766	766	766	7,976
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	0.007614		222	222	222	222	222	222	222	222	222	222	222	222	2,664
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			5,542	5,645	5,628	5,611	225	4,775	4,767	4,759	4,750	4,741	4,733	4,724	55,900
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			5,542	5,645	5,628	5,611	225	4,775	4,767	4,759	4,750	4,741	4,733	4,724	55,900

For Project: CAIR CTs - TURNER (Project 7.2g)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1 Investments															
a. Expenditures/Additions			$3,590	$1,839	$276	$890	$0	$0	$0	$0	$0	$0	$0	$0	$6,594
b. Clearings to Plant			3,590	1,839	276	890	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		$127,418	131,008	132,846	133,122	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	
3 Less: Accumulated Depreciation		(766)	(1,292)	(1,826)	(2,361)	(2,899)	(1,953)	(2,259)	(2,565)	(2,871)	(3,177)	(3,483)	(3,789)	(4,095)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 *Net Investment (Lines 2 + 3 + 4)*		$126,652	*129,716*	*131,021*	*130,761*	*131,113*	*132,059*	*131,753*	*131,447*	*131,141*	*130,835*	*130,529*	*130,223*	*129,917*	
6 Average Net Investment			128,184	130,368	130,891	130,937	131,586	131,906	131,600	131,294	130,988	130,682	130,376	130,070	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		1,192	1,212	1,217	1,218	1,256	1,227	1,224	1,221	1,218	1,215	1,212	1,210	$14,622
b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		218	222	223	223	230	224	224	223	223	222	222	221	2,675
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	2.74%		526	534	535	538	(946)	306	306	306	306	306	306	306	3,329
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		98	99	100	100	100	100	100	100	100	100	100	100	1,197
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			2,034	2,067	2,075	2,079	640	1,857	1,854	1,850	1,847	1,843	1,840	1,837	21,823
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			2,034	2,067	2,075	2,079	640	1,857	1,854	1,850	1,847	1,843	1,840	1,837	21,823

For Project: CAIR CTs - SUWANNEE (Project 7.2h)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1 Investments															
a. Expenditures/Additions			$3,101	$1,541	$3,877	$1,200	$0	$0	$0	$0	$0	$0	$0	$0	$9,718
b. Clearings to Plant			374,942	1,541	3,877	1,200	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	374,942	376,483	380,360	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	
3 Less: Accumulated Depreciation		0	(670)	(2,016)	(3,376)	(4,740)	(3,016)	(3,690)	(4,364)	(5,038)	(5,712)	(6,386)	(7,060)	(7,734)	
4 CWIP - Non-Interest Bearing		371,841	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$371,841	374,272	374,467	376,984	376,820	378,544	377,870	377,196	376,522	375,848	375,174	374,500	373,826	
6 Average Net Investment			373,057	374,370	375,725	376,902	377,682	378,207	377,533	376,859	376,185	375,511	374,837	374,163	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		3,469	3,482	3,494	3,505	3,552	3,517	3,511	3,505	3,499	3,492	3,486	3,480	$41,992
b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		634	636	639	641	649	643	642	641	640	638	637	636	7,676
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	2.12%		670	1,346	1,360	1,364	(1,724)	674	674	674	674	674	674	674	7,734
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	0.008454		264	265	268	269	269	269	269	269	269	269	269	269	3,218
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			5,037	5,729	5,761	5,779	2,746	5,103	5,096	5,089	5,082	5,073	5,066	5,059	60,620
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			5,037	5,729	5,761	5,779	2,746	5,103	5,096	5,089	5,082	5,073	5,066	5,059	60,620

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2008 through December 2008
CAIR/CAMR Crystal River AFUDC (Project 7.4 Recap)

For Project: CAIR/CAMR Crystal River AFUDC - Access Road and Vehicle Barrier System (Project 7.4a)
(in Dollars)

Base

Line Description		Beginning of Period Amount	Actual Jan-08	Actual Feb-08	Actual Mar-08	Actual Apr-08	Actual May-08	Actual Jun-08	Actual Jul-08	Actual Aug-08	Actual Sep-08	Actual Oct-08	Actual Nov-08	Actual Dec-08	End of Period Total
1 Investments															
a. Expenditures/Additions			$0	$0	$0	$0	$0	$52,616	($197,964)	68,803	408,413	$0	$134,790	$1	$466,658
b. Clearings to Plant			0	0	0	0	15,150,677	101,267	$298,338	67,809	408,520	(665)	136,729	1	
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	15,150,677	15,251,944	15,550,281	15,618,090	16,026,610	16,025,945	16,162,674	16,162,675	
3 Less: Accumulated Depreciation		0	0	0	0	0	(21,401)	(64,488)	(108,418)	(152,539)	(197,814)	(243,087)	(288,747)	(334,407)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	(48,651)	0	0	0	(666)	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$0	0	0	0	0	15,129,277	15,138,805	15,441,864	15,465,552	15,828,797	15,782,193	15,873,928	15,828,268	
6 Average Net Investment			0	0	0	0	7,564,638	15,134,041	15,290,334	15,453,708	15,647,175	15,805,495	15,828,061	15,851,098	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		0	0	0	0	70,351	140,747	142,200	143,719	145,519	146,991	147,201	147,415	$1,084,143
b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		0	0	0	0	12,860	25,728	25,994	26,271	26,600	26,869	26,908	26,947	198,177
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	3.39%		0	0	0	0	21,401	43,087	43,930	44,121	45,275	45,273	45,660	45,660	334,407
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	0.010707		0	0	0	0	13,518	13,608	13,874	13,935	14,299	14,299	14,421	14,421	112,375
e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
f. 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	118,130	223,170	225,998	228,046	231,693	233,432	234,190	234,443	1,729,102
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			0	0	0	0	118,130	223,170	225,998	228,046	231,693	233,432	234,190	234,443	1,729,102

For Project: CAIR/CAMR Crystal River AFUDC - UNIT 4 LNB/AH (Project 7.4b)
(in Dollars)

Intermediate

Line Description		Beginning of Period Amount	Actual Jan-00	Actual Jan-00	Actual Jan-00	Actual Jan-00	Actual Jan-00	Actual Jan-00	Actual Jan-00	Actual Jan-00	Actual Jan-00	Actual Jan-00	Actual Jan-00	Actual Jan-00	End of Period Total
1 Investments															
a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$308,085	$308,085
b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	5,599,409	
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	5,599,409	
3 Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	(6,603)	
4 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	5,592,806	
6 Average Net Investment			0	0	0	0	0	0	0	0	0	0	0	2,796,403	
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	0	26,007	$26,007
b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		0	0	0	0	0	0	0	0	0	0	0	4,754	4,754
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	2.83%		0	0	0	0	0	0	0	0	0	0	0	6,603	6,603
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	0.010707		0	0	0	0	0	0	0	0	0	0	0	4,996	4,996
e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
f. 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	42,360	42,360
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	42,360	42,360

CONFIDENTIAL

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 22
COMPANY Progress Energy Florida, Inc.
WITNESS Patricia Q. West (PQW-1) (Confidential)
DATE 11/02/09

Docket No. 090007-EI
Progress Energy Florida
Witness: Patricia Q. West
Exhibit No. __ (PQW-1)

REDACTED

Progress Energy Florida

Review of Integrated Clean Air Compliance Plan

Submitted to the Florida Public Service Commission

April 1, 2009

Progress Energy

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Executive Summary

In the 2007 Environmental Cost Recovery Clause (ECRC) Docket (No. 070007-EI) and as reaffirmed in the 2008 ECRC Docket (No. 080007-EI), the Public Service Commission approved Progress Energy Florida's (PEF's) updated Integrated Clean Air Compliance Plan (Plan D) as a reasonable and prudent means to comply with the requirements of the Clean Air Interstate Rule (CAIR), the Clean Air Mercury Rule (CAMR), the Clean Air Visibility Rule (CAVR) and related regulatory requirements. In its final order, the Commission also directed PEF to file as part of its ECRC true-up testimony "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." This report provides the required review for 2009.

The primary components of PEF's Compliance Plan "D" are summarized as follows:

Sulfur Dioxide (SO_2):

- Installation of wet scrubbers, flue gas desulphurization system, (FGD) 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 SO_2 allowances

Nitrogen Oxides (NOx):

- Installation of low NOx burners (LNBs) and selective catalytic reduction (SCR) on Crystal River Units 4 and 5
- Installation of LNBs and separated over-fire air (LNB/SOFA) or alternative NOx controls at Anclote Units 1 and 2
- Purchase of annual and ozone season NOx allowances

Mercury:

- Co-benefit of wet scrubbers and SCRs at Crystal River Units 4 and 5
- Installation of powdered activated carbon (PAC) injection on Crystal River Unit 2
- Purchase of mercury (Hg) allowances

As detailed in PEF's 2007 ECRC filing, PEF decided upon Plan D based on a quantitative and qualitative evaluation of the ability of alternative plans to meet environmental requirements, while managing risks and controlling costs. That evaluation demonstrated that Plan D is PEF's most cost-effective alternative to meet the applicable regulatory requirements. The Plan is expected to meet environmental requirements by striking a balance between reducing emissions, primarily through the installation of controls on PEF's largest and newest coal units (Crystal River Units 4 and 5), and making strategic use of emission allowance markets.

In accordance with the Commission's final order in the 2007 ECRC docket, PEF has reviewed the efficacy of Plan D and the cost-effectiveness of retrofit options in relation to expected changes in environmental regulations. With regard to Plan D's efficacy, PEF remains confident that Plan D will have the desired effect of achieving timely compliance with the applicable regulations in a cost-effective manner. PEF has achieved several project milestones, including:

- Completion of the access road in May, 2008;
- Completion of the vehicle barrier system in May, 2008;
- Completion of the flue gas chimney shell in June, 2008;
- Completion of the Crystal River Unit 5 FGD absorber tower in September, 2008; and
- Completion of the Crystal River Unit 4 LNB/AH in December, 2008

Although there are uncertainties associated with all major construction projects of this type, the Crystal River projects currently are on-schedule to achieve compliance with the applicable regulations.

As a result of a 2008 federal appeals court decision vacating the federal CAMR regulations, the U.S. Environmental Protection Agency (EPA) is proceeding with adoption of new standards for utility mercury emissions. This development does not immediately impact PEF's implementation of Plan D because the plan does not contemplate installation of mercury-specific controls until 2017 if necessary. Thus, Plan D provides PEF flexibility to respond when EPA adopts any new mercury standards.

Since last year's filing, a federal appellate court also issued a decision remanding CAIR to the EPA to correct several flaws identified by the court. Although the court originally vacated the rule, in response to EPA's petition for rehearing, the court subsequently decided to remand CAIR without vacating it, thereby leaving the rule and its compliance obligations in place.

No new or revised environmental regulations have been adopted that have a direct bearing on PEF's compliance plan. In 2008, the Florida Legislature adopted legislation authorizing the Florida Department of Environmental Protection (FDEP) to adopt rules establishing a cap-and-trade program to regulate emissions of greenhouse gases, such as carbon dioxide (CO_2). To date, FDEP has not adopted any cap-and-trade rules and, under the legislation, any such rules must be ratified by the Legislature, however, the FDEP has begun the rulemaking process and held a public workshop on March 11, 2009. Nevertheless, PEF is taking steps to reduce CO_2 emissions consistent with the state's goals. Among other things, the Company has agreed to retire Crystal River Units 1 and 2 as coal-fired units after the second of two new, advanced design nuclear units in Levy County completes its first fuel cycle. This will reduce PEF's CO_2 emissions by approximately 5 million tons per year.

There currently are no demonstrated retrofit options to reduce CO_2 emissions from fossil fuel-fired electric generating units such as Crystal River Units 4 and 5, which are the primary focus of PEF's compliance plan. Likewise, replacement of coal-fired generation from Crystal River Units 4 and 5 with natural-gas fired generation is not a feasible or cost-effective option because it cannot be implemented in time to meet the 2009 and 2010 CAIR deadlines and it would put PEF in the vulnerable position of relying solely on SO_2 and NOx allowance purchases to achieve compliance during the five to six year interim period it would take to construct a new generating facility. Furthermore, replacing coal-fired generation with gas-fired generation would decrease PEF's fuel diversity and potentially increase fuel price volatility.

I. Introduction

In its final order in the 2007 ECRC Docket (No. 070007-EI) and as reaffirmed in the 2008 ECRC Docket (No. 080007-EI), the Public Service Commission approved PEF's updated Integrated Clean Air Compliance Plan (Plan D) as a reasonable and prudent means to comply with the requirements of CAIR, CAMR, CAVR and related regulatory requirements. *In re*

Environmental Cost Recovery Clause, Order No. PSC-07-0922-FOF-EI, p. 8 (Nov. 16, 2007) the Commission specifically found that "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." *Id.* In its final order, the Commission also directed PEF to file as part of its ECRC true-up testimony "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." *Id.* The purpose of this report is to provide the required review for 2009.

II. PEF's Integrated Clean Air Compliance Plan

A. Background

The CAIR and CAVR programs require PEF and other utilities to significantly reduce emissions of sulfur dioxide (SO_2) and nitrogen oxides (NOx). Under CAIR, these reductions must be met in incremental phases. Phase I begins in 2009 for NOx and in 2010 for SO_2. Phase II begins in 2015 for both NOx and SO_2.

In March 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. The analysis included an examination of the projected emissions associated with several alternative plans and a comparison of economic impacts, in terms of cumulative present value of revenue requirements. 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.

In June 2007, PEF submitted an updated report and supporting testimony summarizing the status of the Plan and an updated economic analysis incorporating certain plan revisions necessitated by changed circumstances. Consistent with the approach utilized in 2006, PEF performed a quantitative evaluation to compare the ability of the modified alternative plans to meet environmental requirements, while managing risks and controlling costs. That evaluation demonstrated that Plan D, as revised, is PEF's most cost-effective alternative to meet the applicable regulatory requirements. Based on that analysis, the Commission approved PEF's

Plan D as reasonable and prudent and held that PEF should recover the prudently incurred costs of implementing the plan.

B. PEF's Plan "D"

PEF's compliance plan (Plan D) meets the applicable environmental requirements by striking a good balance between reducing emissions, primarily through installation of controls on PEF's largest and newest coal units (Crystal River Units 4 and 5), and making strategic use of the allowance markets to comply with CAIR requirements. Specific components of the Plan are summarized below.

1. CAIR SO_2 Plan

The most significant component of PEF's Integrated Clean Air Compliance Plan is the installation of flue gas desulfurization (FGD) systems, also known as wet scrubbers, on Crystal River Units 4 and 5 to comply with CAIR's SO_2 requirements. PEF also plans to purchase limited SO_2 allowances. The plan also includes switching Crystal River Units 1 and 2 to burn low-sulfur (1.2 lbs SO_2/mmBtu) "compliance" coal, and burning low sulfur oil at Anclote Units 1 and 2. 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 along with other relevant fuel selection considerations.

2. CAIR NOx Plan

The primary component of PEF's NOx compliance plan is the installation of low NOx burners (LNBs) and selective catalytic reduction (SCR) systems on Crystal River Units 4 and 5. Currently, the Plan also includes installation of LNB/SOFA controls to reduce NOx emissions from the Anclote units. However, 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. Alternative technology trials and studies for alternative NOx controls are being evaluated to more thoroughly quantify costs, effectiveness, benefits, and risks. Technologies being evaluated for studies and trials include, but are not limited to, selective non-catalytic reduction (SNCR), fuel oil additives, and burner tip modifications. To achieve compliance with CAIR, PEF plans to take strategic advantage of CAIR's cap-and-trade feature by purchasing some annual and ozone season NOx allowances.

3. Mercury Plan

As discussed more fully below, a federal appeals court vacated the federal CAMR regulations in 2008. With CAMR vacated, PEF is not required at this time to install mercury controls to meet the CAMR emission limits. This development does not have any immediate, significant impact on PEF's implementation of Plan D because installation of NOx and SO_2 controls on Crystal River Units 4 and 5 is expected to reduce mercury emissions by at least 80% and the plan did not contemplate installation of any mercury-specific controls until 2017. PEF will continue to monitor the regulatory developments related to utility mercury emissions as well as research and development of mercury control technologies to ensure that the most reliable and cost-effective control technology is used when the time arrives for compliance.

4. CAVR Visibility Plan

PEF operates four units that are potentially subject to Best Available Retrofit Technology (BART) under CAVR, including Anclote Units 1 and 2 and Crystal River Units 1 and 2. As indicated above, PEF's Compliance Plan includes switching to low-sulfur oil and the installation of LNBs at Anclote Units 1 and 2 or other alternative NOx controls such as selective non-catalytic reduction, fuel oil additives, combustion control technologies, and burner tip modifications. Per the FDEP'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. Based on modeled impact of particulate matter on visibility Anclote Units 1 and 2 were determined to be exempt from BART in April 2008. Because the results of the modeling for Crystal River Units 1 and 2 showed visibility impacts at or above regulatory threshold levels, PEF applied for a BART permit for those units. This permit was issued on February 26, 2009 and it establishes a combined BART emission standard for Crystal River Units 1 and 2. By establishing a combined emission standard, the permit enables PEF to cost-effectively satisfy BART requirements by maintaining the existing Unit 1 electrostatic precipitator (ESP) and upgrading the Unit 2 ESP if necessary,

III. Efficacy of PEF's Plan D

As noted above, in its Final Order in Docket No. 070007- EI, the Commission requested a review of the efficacy of PEF's Integrated Clean Air Compliance Plan (Plan D) and the cost-effectiveness of PEF's retrofit options for each generating unit in relation to expected changes in environmental regulations. With regard to Plan D's efficacy, PEF remains confident that Plan D will have the desired effect of achieving timely compliance with the applicable regulations in a cost-effective manner. As noted below, however, there are uncertainties that could affect the timing and costs of implementation.

A. Project Milestones

PEF remains on schedule to complete installation of controls on Crystal River Units 4 and 5 as contemplated in PEF's 2008 ECRC filing. As discussed in previous filings, PEF has executed contracts for specific project components, as well as an overall Engineering, Construction and Procurement (EPC) contract. Since the submittal of last year's annual review, PEF has achieved the following project milestones:

ACHIEVED CAIR COMPLIANCE MILESTONES

Access Road CRN – Common	Apr-08
Chimney Shell Complete – Common	May-08
Limestone Prep steel complete – Common	Jul-08
Scheduled Equipment Delivery complete – Crystal River Unit 4 LNB	Aug-08
FGD building steel complete – Crystal River Unit 5 FGD	Sep-08
SCR Steel complete – Crystal River Unit 5 SCR	Sep-08
SCR Foundation complete – Crystal River Unit 4 SCR	Sep-08
Access Road Piping delivered – Crystal River Unit 4 FGD	Oct-08
Air pre-heater baskets delivered – Crystal River Unit 5 FGD	Dec-08
LNB scheduled equipment delivery complete – Crystal River Unit 5 SCR	Dec-08
Urea equipment delivery – Common	Dec-08
Crystal River Unit 4 LNB Installation complete	Dec-08

PEF expects to achieve the following project milestones in 2009 and 2010:

UPCOMING CAIR COMPLIANCE MILESTONES

FGD building steel delivery complete - Crystal River Unit 4 FGD	Mar-09	
[redacted]	[redacted]	1
[redacted]	[redacted]	2
Limestone handling complete – Common	Sep - 09	
[redacted]	[redacted]	3
SCR Steel erection work complete - Crystal River Unit 4 SCR	Dec-09	
[redacted]	[redacted]	4
[redacted]	[redacted]	5
[redacted]	[redacted]	6

B. Projects Costs

During 2008, PEF had incurred approximately $568 million in capital costs for the Crystal River projects. The 2008 figure includes approximately $511 million in contract billings, $13 million of owner's costs, and $44 million of AFUDC. As of December 2008, the life-to-date capital costs were approximately $897 million. This figure includes approximately $812 million in contract billings, $34 million of owner's costs, and $51 million of AFUDC. The contract billings include payments for: major construction work, design and engineering work, procurement of major equipment, and environmental permits. The overall budget, excluding AFUDC, is $1.15 billion. Currently, the costs are on track to be completed within the overall budget.

C. Uncertainties

While a significant amount of study, engineering, and analysis have been completed and construction has begun on the Crystal River projects, there are still a number of uncertainties that could affect project schedules and costs. Although most of PEF's contracts contain provisions for liquidated damages for delays, the non-performance of contractors, force majeure events, and other uncertainties could adversely impact project schedules and costs. The primary risks identified on the PEF CAIR compliance projects are as follows:

- **EPCR adherence to the outage schedules:** EPCR has finalized the schedule according to the planned outage dates. PEF personnel will monitor the schedule and identify any potential issues.

- **Force Majeure:** There is a risk of a major storm impacting this project considering the location is directly on the Gulf Coast.

- **Scope Modifications:** There are risks of design errors, quantity changes, site conditions, site interferences, change requests or other items which would require additional scope. A project contingency has been developed to cover these unknowns. A process is in place to track these contingencies on a monthly basis in order to trend and project future costs.

- **Condition of Certification (COC) Modification delay:** A lengthy delay in the FDEP's approval of the Gypsum Storage Pad design could create a delay in receiving the necessary modifications to the existing Conditions of Certification for Crystal River Units 4 and 5. This approval is now expected by the end of April 2009.

Primary risks to date are discussed above; however, emergent risks could still occur. Project contingency has been developed to cover these project unknowns, and PEF project staff members are actively engaged to minimize or avoid any project schedule impacts.

IV. Retrofit Options in Relation to Expected Changes in Environmental Regulations

Since PEF's filing in the 2008 ECRC docket, no new or revised environmental regulations have been adopted that have a direct bearing on Plan D. Furthermore, at this time, it is not possible to predict the timing or requirements of any environmental regulations that may be adopted in the future. The following discussion addresses three regulatory developments that have been the topic of discussion since PEF's 2008 filing.

A. Status of CAIR

In July 2008, the U.S. Circuit Court of Appeals for the District of Columbia issued a decision vacating CAIR in its entirety. *North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008). However, in response to EPA's petition for rehearing, the court requested briefs from the parties regarding whether CAIR should be remanded to EPA without vacatur of CAIR. On December 23, the court decided to remand CAIR without vacatur, thereby leaving the rule and its compliance obligations in place. *North Carolina v. EPA*, 550 F.3d 1176 (D.C. Cir. 2008). Thus, PEF must continue to move forward with its Integrated Clean Air Compliance Plan in order to meet the impending CAIR compliance deadlines.

B. Status of CAMR

In February 2008, the U.S. Court of Appeals for the District of Columbia (D.C.) Circuit vacated the federal CAMR regulations. *See*, *New Jersey v. EPA*, 517 F. 3d 574 (D.C. Cir. 2008). EPA originally promulgated CAMR under Section 111 of the Clean Air Act (CAA), rather than CAA Section 112, which requires EPA to establish Maximum Achievable Control Technology (MACT) standards for hazardous air pollutants. EPA's decision to proceed under CAA Section 111 was based on its rescission of a prior finding in 2000 that emissions of mercury and other hazardous pollutants from electric generating units should be regulated under CAA Section 112. In its decision, the D.C. Circuit court vacated EPA's rescission of its 2000 finding, holding that the CAA required EPA, prior to making such a rescission, to determine that no utility-unit's mercury emissions exceeded a level that would "protect public health with an ample margin of safety and [have] no adverse environmental effect." Based on this threshold conclusion, the court then vacated CAMR because it was based on EPA's rescission. Since last year's filing, the U.S. Supreme Court has denied review of the D.C. Circuit's vacatur of CAMR and EPA has announced its intention to proceed with a MACT rulemaking.

It is impossible to predict when EPA will complete the MACT rulemaking process or what the emissions standards will be. In any event, because PEF's Plan D relies on the co-benefit of SCR/scrubbers rather than mercury-specific controls until 2017, the Plan provides flexibility to respond to any rules EPA may adopt in response to the D.C. Circuit's decision.

C. *Potential Greenhouse Gas Regulation*

When PEF committed to placing environmental controls on Crystal River Units 4 and 5, climate change issues were only beginning to be discussed. At that time, PEF had to commit to installing controls in order to meet the fast approaching 2009 and 2010 CAIR compliance deadlines. Governor Crist subsequently issued Executive Order 07-127 directing FDEP to promulgate regulations requiring reductions in utility carbon dioxide (CO_2) emissions. In addition, the 2008 Florida Legislature enacted legislation authorizing FDEP to adopt rules establishing a cap-and-trade program and requiring FDEP to submit any such rules for legislative review and ratification. At this time, however, FDEP is still in the early stages of developing cap-and-trade rules and numerous key issues remain unresolved, such as the approach to allowance distribution and whether Florida should join a regional program; a rulemaking workshop was held on March 11, 2009. Until such regulations are adopted and ratified, or legislation is enacted at the federal level, the potential impact of CO_2 regulation will remain uncertain. Nevertheless, PEF is taking steps to reduce CO_2 emissions consistent with the state's goals. In December 2008, the Company announced an agreement with FDEP to retire Crystal River Units 1 and 2 coal-fired units after the second of two new, advanced design nuclear units in Levy County completes its first fuel cycle. Retiring the coal-fired Crystal River Units 1 and 2 will reduce PEF's CO_2 emissions by 5 million tons per year.

At this time, there are still no retrofit options commercially available to reduce CO_2 emissions from fossil fuel-fired electric generating units such as Crystal River Units 4 and 5, which are the primary focus of PEF's compliance plan. To date, there have been no large-scale commercial carbon capture and sequestration technology demonstrations on electric utility units. Until numerous technological, regulatory and liability issues are resolved, it will be impossible to determine whether carbon capture and storage would be a technically feasible or cost-effective means of complying with a CO_2 regulatory regime. Likewise, replacing coal-fired generation from Crystal River Units 4 and 5 with lower CO_2-emitting natural gas-fired combined cycle generation[1] is not a viable option. PEF has already incurred over 73% of the costs, excluding

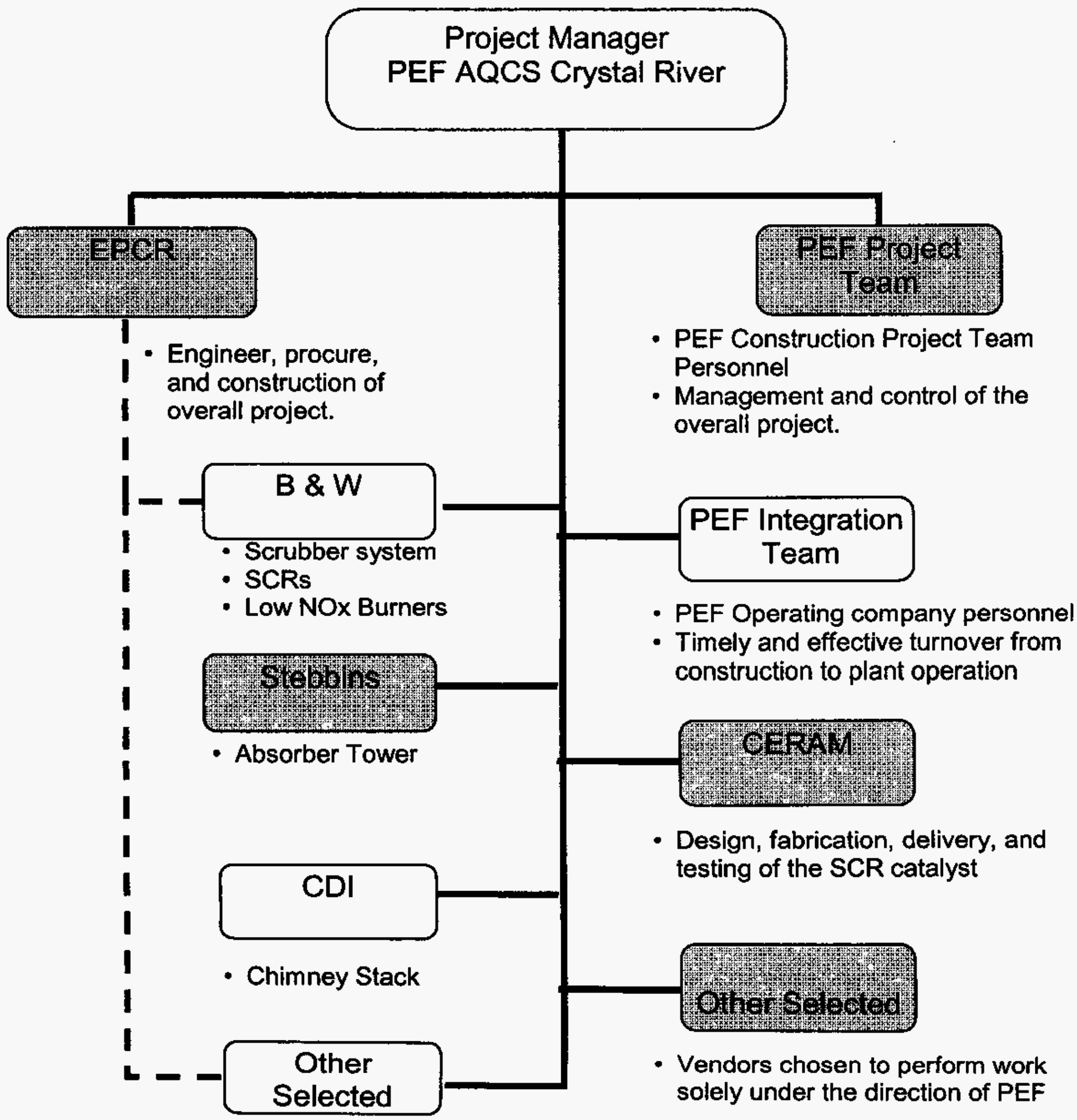
[1] The CO_2 emission rate for natural gas-fired combined cycle (NG/CC) units is approximately 50% of the emission rate for coal-fired generating units. Thus, replacing coal-fired generation with NG/CC would not eliminate costs associated with any to-be-adopted CO_2 regulatory regime.

AFUDC, of Plan D and the major components of the Plan are due to be placed in service in 2009 and 2010. Even if PEF could abandon the Crystal River projects at this late date, sufficient combined-cycle generation could not be placed on-line until the 2015-2016 timeframe. PEF would have to rely solely on allowance markets to achieve and maintain CAIR compliance for five to six years until the combined cycle generation could be placed in service. Given the uncertainty of the CAIR allowance markets, PEF cannot reasonably assume sufficient allowances would be available at reasonable price if PEF were left in the extremely vulnerable position of relying solely on allowance purchases to achieve compliance. Furthermore, replacing Crystal River Units 4 and 5 with gas-fired generation would decrease PEF's fuel diversity and potentially increase fuel price volatility.

V. Conclusion

Based on project milestones achieved to date, PEF remains confident that Plan D will have the desired effect of achieving timely compliance with the applicable regulations in a cost-effective manner. No new or revised environmental regulations have been adopted that have a direct bearing on PEF's compliance plan. Although FDEP is in the process of developing a cap-and-trade program to regulate CO_2 emissions, no regulations have been adopted to date and there currently are no demonstrated retrofit options to reduce CO_2 emissions from fossil fuel-fired electric generating units. Moreover, abandoning the Crystal River Units 4 and 5 emission control projects is not a viable option in light of the imminent 2009 and 2010 CAIR deadlines. Although EPA is proceeding with the adoption of new MACT standards for utility hazardous air pollutant emissions as a result of a federal court decision vacating the federal CAMR rules, this development does not immediately impact PEF's implementation of Plan D because the plan relies primarily on installation of NOx and SO_2 controls to reduce mercury emissions and does not contemplate installation of mercury-specific controls until 2017. For these reasons, PEF's Plan D continues to represent the most cost-effective alternative for achieving and maintaining compliance with the applicable regulatory requirements.

Docket No. 090007-EI
Progress Energy Florida
Witness: Dale Wilterdink
Exhibit No. __ (DW-1)
Crystal River Project Organizational Structure



- Vendors chosen to perform work under contract with PEF by whose day to day activities are coordinated through EPCR.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 23
COMPANY Progress Energy Florida, Inc.
WITNESS KEVIN MURRAY (adopting WILTERDINK'S exhibit) (DW-1)
DATE 11/02/09

Witness: T.G. Foster
Exibit__(TGF-1)

PROGRESS ENERGY FLORIDA, INC.
ENVIRONMENTAL COST RECOVERY
COMMISSION FORMS 42-1E THROUGH 42-8E

JANUARY 2009 - DECEMBER 2009
Calculation of the Current Period Estimated/Actual Amount
Actuals for the period of January through June 2009
Estimated for the period of July through December 2009
DOCKET NO. 090007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 24
COMPANY Progress Energy Florida, Inc.
WITNESS Thomas G. Foster (LC-1)
DATE 11/02/09

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. __(TGF-1)

PROGRESS ENERGY FLORIDA

Form 42-1E

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009
(in Dollars)

Line		Period Amount
1	Over/(Under) Recovery for the Period (Form 42-2E, Line 5)	$ 24,048,806
2	Interest Provision (Form 42-2E, Line 6)	26,775
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 2009 to December 2009 (Lines 1 + 2 + 3)	**$ 24,075,581**

Form 42-2E

PROGRESS ENERGY FLORIDA

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009

End-of-Period True-Up Amount
(in Dollars)

Line	Description		Actual January 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	End of Period Total
1	ECRC Revenues (net of Revenue Taxes)		$9,341,113	$10,005,241	$8,865,089	$8,944,162	$9,976,839	$11,667,770	$ 12,284,738	$ 13,557,651	$ 13,721,854	$ 11,870,704	$ 10,322,832	$ 10,065,650	$130,623,643
2	True-Up Provision	($4,309,712)	(359,143)	(359,143)	(359,143)	(359,143)	(359,143)	(359,143)	(359,143)	(359,143)	(359,143)	(359,143)	(359,143)	(359,143)	(4,309,712)
3	ECRC Revenues Applicable to Period (Lines 1 + 2)		8,981,970	9,646,098	8,505,946	8,585,019	9,617,696	11,308,627	11,925,596	13,198,509	13,362,712	11,511,561	9,963,689	9,706,508	126,313,931
4	Jurisdictional ECRC Costs														
	a. O & M Activities (Form 42-5E, Line 9)		5,079,856	4,901,564	4,490,451	4,178,262	6,932,024	7,553,417	7,323,499	7,967,326	6,546,086	5,739,613	4,661,632	4,410,921	69,784,651
	b. Capital Investment Projects (Form 42-7E, Line 9)		1,293,974	1,301,474	1,295,301	1,267,463	1,256,962	1,874,230	2,888,054	3,270,500	3,213,494	3,163,626	3,121,727	8,533,669	32,480,474
	c. Total Jurisdictional ECRC Costs		6,373,830	6,203,038	5,785,752	5,445,725	8,188,986	9,427,647	10,211,553	11,237,826	9,759,580	8,903,239	7,783,359	12,944,590	102,265,125
5	Over/(Under) Recovery (Line 3 - Line 4c)		2,608,141	3,443,060	2,720,194	3,139,294	1,428,710	1,880,980	1,714,043	1,960,683	3,603,132	2,608,322	2,180,330	(3,238,082)	24,048,806
6	Interest Provision (Form 42-3E, Line 10)		(3,931)	(2,410)	(177)	1,184	1,626	2,058	2,836	3,474	4,386	5,392	6,192	6,145	26,775
7	Beginning Balance True-Up & Interest Provision		(4,309,712)	(1,346,360)	2,453,433	5,532,593	9,032,214	10,821,692	13,063,873	15,139,895	17,463,194	21,429,854	24,402,711	26,948,376	(4,309,712)
	a. Deferred True-Up from January 2008 to December 2008 (Order No. PSC-08-0775-FOF-EI)		(4,320,606)	(4,320,606)	(4,320,606)	(4,320,606)	(4,320,606)	(4,320,606)	(4,320,606)	(4,320,606)	(4,320,606)	(4,320,606)	(4,320,606)	(4,320,606)	(4,320,606)
8	True-Up Collected/(Refunded) (see Line 2)		359,143	359,143	359,143	359,143	359,143	359,143	359,143	359,143	359,143	359,143	359,143	359,143	4,309,712
9	End of Period Total True-Up (Lines 5+6+7+7a+8)		(5,666,966)	(1,867,173)	1,211,987	4,711,608	6,501,086	8,743,270	10,819,289	13,142,588	17,109,248	20,082,105	22,627,770	19,754,975	19,754,975
10	Adjustments to Period Total True-Up Including Interest		0	0	0	0	0	0	0	0	0	0	0	0	0
11	End of Period Total True-Up (Lines 9 + 10)		($5,666,966)	($1,867,173)	$1,211,987	$4,711,608	$6,501,086	$8,743,270	$10,819,289	$13,142,588	$17,109,248	$20,082,105	$22,627,770	$19,754,975	$19,754,975

Form 42-3E

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009

Interest Provision
(in Dollars)

Line	Description	Actual January 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	End of Period Total
1	Beginning True-Up Amount (Form 42-2E, Line 7 + 7a + 10)	($8,630,318)	($5,666,966)	($1,867,173)	$1,211,987	$4,711,608	$6,501,086	$8,743,267	$10,819,289	$13,142,588	$17,109,248	$20,082,105	$22,627,770	
2	Ending True-Up Amount Before Interest (Line 1 + Form 42-2E, Lines 5 + 8)	(5,663,035)	(1,864,763)	1,212,164	4,710,424	6,499,460	8,741,209	10,816,453	13,139,114	17,104,862	20,076,713	22,621,578	19,748,830	
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	(14,293,353)	(7,531,728)	(655,009)	5,922,410	11,211,068	15,242,295	19,559,719	23,958,403	30,247,451	37,185,961	42,703,683	42,376,600	
4	Average True-Up Amount (Line 3 x 1/2)	(7,146,677)	(3,765,864)	(327,505)	2,961,205	5,605,534	7,621,148	9,779,860	11,979,202	15,123,726	18,592,981	21,351,842	21,188,300	
5	Interest Rate (First Day of Reporting Business Month)	0.54%	0.79%	0.75%	0.55%	0.40%	0.30%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
6	Interest Rate (First Day of Subsequent Business Month)	0.79%	0.75%	0.55%	0.40%	0.30%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	0.35%	
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	1.33%	1.54%	1.30%	0.95%	0.70%	0.65%	0.70%	0.70%	0.70%	0.70%	0.70%	0.70%	
8	Average Interest Rate (Line 7 x 1/2)	0.665%	0.770%	0.650%	0.475%	0.350%	0.325%	0.350%	0.350%	0.350%	0.350%	0.350%	0.350%	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.055%	0.064%	0.054%	0.040%	0.029%	0.027%	0.029%	0.029%	0.029%	0.029%	0.029%	0.029%	
10	Interest Provision for the Month (Line 4 x Line 9)	($3,931)	($2,410)	($177)	$1,184	$1,626	$2,058	$2,836	$3,474	$4,386	$5,392	$6,192	$6,145	$26,775

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009

Form 42-4E

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 - Demand	$2,378,173	$3,690,681	($1,312,508)	-36%
	1a Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention - Demand	1,724,902	3,140,557	(1,415,655)	-45%
	2 Distribution System Environmental Investigation, Remediation, and Pollution Prevention - Demand	8,240,519	8,311,000	(70,481)	-1%
	3 Pipeline Integrity Management - Demand	1,101,000	1,101,000	0	0%
	4 Above Ground Tank Secondary Containment - Demand	0	0	0	N/A
	5 SO2 & NOx Emissions Allowances - Energy	52,637,496	71,976,198	(19,338,701)	-27%
	6 Phase II Cooling Water Intake - Demand	0	0	0	N/A
	6.a Phase II Cooling Water Intake 316(b) - Intm	0	0	0	N/A
	7.2 CAIR/CAMR - Peaking - Demand	45,176	67,700	(22,524)	-33%
	7.4 CAIR/CAMR Crystal River - Base	1,463,838	1,429,627	34,211	2%
	7.4 CAIR/CAMR Crystal River - Energy	2,080,814	2,662,344	(581,530)	-22%
	7.4 CAIR/CAMR Crystal River - A&G	14,737	0	14,737	100%
	8 Arsenic Groundwater Standard - Base - Demand	0	77,669	(77,669)	-100%
	9 Sea Turtle - Coastal Street Lighting - Distrib - Demand	5,000	5,000	0	0%
	11 Modular Cooling Towers - Base - Demand	3,336,752	3,336,752	0	0%
	12 Greenhouse Gas Inventory and Reporting - Energy	14,000	56,680	(42,680)	-75%
	13 Mercury Total Daily Maximum Loads Monitoring - Energy	92,164	0	92,164	100%
2	Total O&M Activities - Recoverable Costs	**$73,134,571**	**$95,855,207**	**($22,720,636)**	-24%
3	Recoverable Costs Allocated to Energy	54,824,475	74,695,222	(19,870,747)	-27%
4	Recoverable Costs Allocated to Demand	18,310,097	21,159,986	(2,849,889)	-13%

Notes:

Column (1) is the End of Period Totals on Form 42-5E
Column (2) = Original projection Form 42-2P
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Form 42-5E

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009

O&M Activities
(in Dollars)

Line	Description	Actual January 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	End of Period Total
1	Description of O&M Activities													
	1 Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$310,544	$231,198	$112,097	$172,601	$174,868	$338,708	$173,026	$173,026	$173,026	$173,026	$173,026	$173,026	$2,378,173
	1a Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	96,799	201,026	154,349	393,125	188,128	93,748	99,621	99,621	99,621	99,621	99,621	99,621	1,724,902
	2 Distribution System Environmental Investigation, Remediation, and Pollution Prevention	586,740	640,834	798,795	587,011	1,184,896	932,243	711,000	758,500	742,000	842,500	427,000	29,000	8,240,519
	3 Pipeline Integrity Management, Review/Update Plan and Risk Assessments - Intm	(120,417)	67,763	(4,034)	12,164	54,775	43,095	60,715	80,715	127,896	384,896	212,896	180,536	1,101,000
	4 Above Ground Tank Secondary Containment - Pkg	0	0	0	0	0	0	0	0	0	0	0	0	0
	5 SO2 & NOx Emissions Allowances - Energy	4,416,716	3,996,452	3,547,922	3,170,590	4,725,882	5,603,579	5,242,537	5,796,052	5,136,181	3,989,011	3,635,800	3,376,773	52,637,496
	6 Phase II Cooling Water Intake 316(b) - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
	6a Phase II Cooling Water Intake 316(b) - Intm	0	0	1,288	(1,288)	0	0	0	0	0	0	0	0	0
	7.2 CAIR/CAMR - Peaking	0	0	39,069	1,288	4,819	0	0	0	0	0	0	0	45,176
	7.4 CAIR/CAMR Crystal River - Base	0	0	0	4,284	39,769	44,100	215,485	215,485	215,485	215,485	256,872	256,872	1,463,838
	7.4 CAIR/CAMR Crystal River - Energy	0	0	0	0	0	0	336,662	357,280	353,463	370,622	132,047	530,741	2,080,814
	7.4 CAIR/CAMR Crystal River - A&G	572	1,011	1,158	2,280	465	1,883	1,228	1,228	1,228	1,228	1,228	1,228	14,737
	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	0	0	0	833	833	833	833	833	833	5,000
	11 Modular Cooling Towers - Base	0	0	0	0	834,188	834,188	834,188	834,188		0	0	0	3,336,752
	12 Greenhouse Gas Inventory and Reporting - Energy	0	0	0	0	0	0	2,333	2,333	2,333	2,333	2,333	2,333	14,000
	13 Mecrury Total Daily Maximum Loads Monitoring - Energy	0	0	0	0	0	0	0	46,082	23,041	0	0	23,041	92,164
2	Total of O&M Activities	5,290,954	5,138,284	4,650,644	4,342,055	7,207,790	7,891,544	7,677,629	8,365,344	6,875,107	6,079,557	4,941,657	4,674,006	$73,134,571
3	Recoverable Costs Allocated to Energy	4,416,716	3,996,452	3,547,922	3,170,590	4,725,882	5,603,579	5,581,532	6,201,748	5,515,017	4,361,967	3,770,180	3,932,889	54,824,475
4	Recoverable Costs Allocated to Demand - Transm	310,544	231,198	112,097	172,601	174,868	338,708	173,026	173,026	173,026	173,026	173,026	173,026	2,378,173
	Recoverable Costs Allocated to Demand - Distrib	683,539	841,860	953,144	980,136	1,373,024	1,025,991	811,455	858,955	842,455	942,955	527,455	129,455	9,970,421
	Recoverable Costs Allocated to Demand - Prod-Base	0	0	0	4,284	873,957	878,288	1,049,673	1,049,673	215,485	215,485	256,872	256,872	4,800,590
	Recoverable Costs Allocated to Demand - Prod-Intm	(120,417)	67,763	(2,746)	10,876	54,775	43,095	60,715	80,715	127,896	384,896	212,896	180,536	1,101,000
	Recoverable Costs Allocated to Demand - Prod-Peaking	0	0	39,069	1,288	4,819	0	0	0	0	0	0	0	45,176
	Recoverable Costs Allocated to Demand - A&G	572	1,011	1,158	2,280	465	1,883	1,228	1,228	1,228	1,228	1,228	1,228	14,737
5	Retail Energy Jurisdictional Factor	0.96780	0.96220	0.96630	0.96650	0.96780	0.96960	0.96030	0.95790	0.95750	0.95620	0.95590	0.95990	
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	
	Retail Production Demand Jurisdictional Factor - A&G	0.91670	0.91670	0.91670	0.91670	0.91670	0.91670	0.91670	0.91670	0.91670	0.91670	0.91670	0.91670	
7	Jurisdictional Energy Recoverable Costs (A)	4,274,498	3,845,387	3,428,357	3,064,376	4,573,709	5,433,231	5,359,945	5,940,654	5,280,629	4,170,913	3,603,915	3,775,180	52,750,794
8	Jurisdictional Demand Recoverable Costs - Transm (B)	219,235	163,219	79,137	121,851	123,452	239,118	122,151	122,151	122,151	122,151	122,151	122,151	1,678,918
	Jurisdictional Demand Recoverable Costs - Distrib (B)	680,784	838,467	949,303	976,186	1,367,491	1,021,856	808,184	855,493	839,059	939,154	525,329	128,933	9,930,239
	Jurisdictional Demand Recoverable Costs - Prod-Base (B)	0	0	0	4,016	819,361	823,421	984,100	984,100	202,024	202,024	240,825	240,825	4,500,696
	Jurisdictional Demand Recoverable Costs - Prod-Intm (B)	(95,185)	53,564	(2,171)	8,597	43,297	34,065	47,993	63,802	101,097	304,245	168,286	142,706	870,296
	Jurisdictional Demand Recoverable Costs - Prod-Peaking (B)	0	0	34,763	1,146	4,288	0	0	0	0	0	0	0	40,197
	Jurisdictional Demand Recoverable Costs - A&G (B)	524	927	1,062	2,090	426	1,726	1,126	1,126	1,126	1,126	1,126	1,126	13,511
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$5,079,856	$4,901,564	$4,490,451	$4,178,262	$6,932,024	$7,553,417	$7,323,499	$7,967,326	$6,546,086	$5,739,613	$4,661,632	$4,410,921	$69,784,651

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

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. __ (TGF-1)

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009

Form 42-6E

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				
	3.1 Pipeline Integrity Management - Bartow/Anclote Pipeline-Intermediate - Demand	$581,294	$606,258	($24,964)	-4%
	4.x Above Ground Tank Secondary Containment - Demand	1,756,027	1,612,041	143,986	9%
	5 SO2/NOx Emissions Allowances - Energy	7,656,333	6,974,894	681,439	10%
	7.x CAIR/CAMR - Demand/Energy	24,406,536	35,475,761	(11,069,225)	-31%
	9 Sea Turtle - Coastal Street Lighting -Distribution - Demand	2,692	7,202	(4,510)	-63%
	10.x Underground Storage Tanks-Base - Demand	40,475	40,453	22	0%
	11 Modular Cooling Towers - Base - Demand	176,235	176,379	(144)	0%
	11.1 Thermal Discharge Permanent Cooling Tower - Base - Demand	0	0	0	N/A
2	Total Capital Investment Activities - Recoverable Costs	**34,619,592**	**44,892,988**	**($10,273,396)**	-23%
3	Recoverable Costs Allocated to Energy	7,656,333	6,974,894	681,439	10%
4	Recoverable Costs Allocated to Demand	$26,963,259	$37,918,094	($10,954,835)	-29%

Notes:

Column (1) is the End of Period Totals on Form 42-7E
Column (2) = Original projection Form 42-3P
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. ___ (TGF-1)

Form 42-7E

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line	Description	Actual January 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	End of Period Total
1	Description of Investment Projects (A)													
	3 Pipeline Integrity Management - Bartow/Anclote Pipeline-Intermediate	$48,725	$48,351	$48,671	$48,800	$48,813	$48,679	$48,545	$48,410	$48,276	$48,143	$48,008	$47,873	$581,294
	4.1 Above Ground Tank Secondary Containment - Peaking	98,857	103,069	104,497	105,927	111,749	115,907	117,039	118,577	120,199	120,558	122,234	124,294	1,362,907
	4.2 Above Ground Tank Secondary Containment - Base	26,972	28,378	29,241	29,187	29,133	29,080	29,026	28,971	28,917	28,863	28,809	28,756	345,333
	4.3 Above Ground Tank Secondary Containment - Intermediate	4,032	4,022	4,014	4,004	3,996	3,987	3,977	3,969	3,960	3,951	3,942	3,933	47,787
	5 SO2/NOX Emissions Allowances - Energy	815,098	814,229	808,418	781,925	739,597	689,577	637,428	576,716	516,588	466,400	424,463	385,894	7,656,333
	7.1 CAIR/CAMR Anclote- Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0
	7.2 CAIR CT's - Peaking	25,784	25,742	25,704	25,662	25,621	25,581	25,542	25,501	25,461	25,420	25,380	25,340	306,738
	7.3 CAMR Crystal River - Base	3,165	3,172	3,179	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	38,137
	7.4 CAIR/CAMR Crystal River AFUDC - Base	327,095	335,936	329,460	325,670	351,772	1,056,879	2,196,867	2,666,418	2,664,403	2,659,866	2,655,200	8,463,717	24,033,283
	7.4 CAIR/CAMR Crystal River AFUDC - Energy	0	0	0	0	0	0	870	1,740	3,307	6,442	8,010	8,010	28,378
	9 Sea Turtle - Coastal Street Lighting -Distribution	156	156	155	155	155	153	172	208	271	326	362	424	2,692
	10.1 Underground Storage Tanks-Base	2,370	2,366	2,360	2,355	2,350	2,344	2,340	2,335	2,330	2,325	2,320	2,315	28,108
	10.2 Underground Storage Tanks-Intermediate	1,043	1,041	1,038	1,036	1,034	1,032	1,029	1,027	1,025	1,023	1,021	1,018	12,366
	11 Modular Cooling Towers - Base	15,357	15,235	15,113	14,991	14,869	14,747	14,625	14,503	14,381	14,259	14,137	14,016	176,235
	11.1 Thermal Discharge Permanent Cooling Tower - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Total Investment Projects - Recoverable Costs	1,368,654	1,381,697	1,371,850	1,342,892	1,332,269	1,991,145	3,080,640	3,491,555	3,432,299	3,380,756	3,337,065	9,108,770	**34,619,592**
3	Recoverable Costs Allocated to Energy	815,098	814,229	808,418	781,925	739,597	689,577	638,298	578,455	519,895	472,842	432,473	393,904	7,684,711
	Recoverable Costs Allocated to Demand - Distribution	156	156	155	155	155	153	172	208	271	326	362	424	2,692
4	Recoverable Costs Allocated to Demand - Production - Base	374,959	385,087	379,353	375,383	401,304	1,106,230	2,246,038	2,715,407	2,713,211	2,708,493	2,703,646	8,511,983	24,621,097
	Recoverable Costs Allocated to Demand - Production - Intermediate	53,800	53,414	53,723	53,840	53,843	53,698	53,551	53,406	53,261	53,117	52,971	52,824	641,447
	Recoverable Costs Allocated to Demand - Production - Peaking	124,641	128,811	130,201	131,589	137,370	141,488	142,581	144,078	145,660	145,978	147,614	149,634	1,669,645
5	Retail Energy Jurisdictional Factor	0.96780	0.96220	0.96630	0.96650	0.96780	0.96960	0.96030	0.95790	0.95750	0.95620	0.95590	0.95990	
	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)	788,852	783,451	781,174	755,731	715,782	668,614	612,957	554,102	497,800	452,131	413,401	378,108	7,402,104
	Jurisdictional Demand Recoverable Costs - Distribution (B)	155	156	154	154	154	152	171	207	270	325	360	423	2,681
8	Jurisdictional Demand Recoverable Costs - Production - Base (C)	351,535	361,031	355,655	351,933	376,235	1,037,124	2,105,728	2,545,776	2,543,717	2,539,294	2,534,749	7,980,240	23,083,017
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	42,527	42,221	42,466	42,558	42,561	42,446	42;330	42,215	42,101	41,987	41,871	41,756	507,039
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	110,904	114,615	115,852	117,087	122,230	125;895	126,867	128,199	129,607	129,890	131,345	133,143	1,485,633
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$1,293,974	$1,301,474	$1,295,301	$1,267,463	$1,256,962	$1,874,230	$2,888,054	$3,270,500	$3,213,494	$3,163,626	$3,121,727	$8,533,669	$32,480,473

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

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: PIPELINE INTEGRITY MANAGEMENT - Bartow/Anclote Pipeline (Project 3.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	End of Period Total
1	Investments															
	a. Expenditures/Additions			($187,531)	$82,276	$0	$27,105	$0	$0	$0	$0	$0	$0	$0	$0	($78,151)
	b. Clearings to Plant			(187,531)	82,276	0	27,105	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		$3,657,886	3,470,355	3,552,631	3,552,631	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	
3	Less: Accumulated Depreciation		(419,544)	(431,372)	(443,481)	(455,590)	(467,792)	(479,994)	(492,196)	(504,398)	(516,600)	(528,802)	(541,004)	(553,206)	(565,408)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		3,238,343	3,038,983	3,109,150	3,097,041	3,111,944	3,099,742	3,087,540	3,075,338	3,063,136	3,050,934	3,038,732	3,026,530	3,014,328	
6	Average Net Investment			3,138,663	3,074,067	3,103,096	3,104,492	3,105,843	3,093,641	3,081,439	3,069,237	3,057,035	3,044,833	3,032,631	3,020,429	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		29,189	28,588	28,858	28,873	28,885	28,771	28,657	28,544	28,430	28,317	28,203	28,090	343,405
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		5,336	5,226	5,276	5,278	5,279	5,259	5,239	5,217	5,197	5,177	5,156	5,134	62,774
	c. Other															-
8	Investment Expenses															
	a. Depreciation (C)			11,828	12,109	12,109	12,202	12,202	12,202	12,202	12,202	12,202	12,202	12,202	12,202	145,864
	b. Amortization			-	-	-	-	-	-	-	-	-	-	-	-	-
	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)			2,372	2,428	2,428	2,447	2,447	2,447	2,447	2,447	2,447	2,447	2,447	2,447	29,251
	e. Other			-	-	-	-	-	-	-	-	-	-	-	-	-
9	Total System Recoverable Expenses (Lines 7 + 8)			48,725	48,351	48,671	48,800	48,813	48,679	48,545	48,410	48,276	48,143	48,008	47,873	581,294
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	-
	b. Recoverable Costs Allocated to Demand			48,725	48,351	48,671	48,800	48,813	48,679	48,545	48,410	48,276	48,143	48,008	47,873	581,294
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	0.79046
12	Retail Energy-Related Recoverable Costs (E)			-	-	-	-	-	-	-	-	-	-	-	-	0
13	Retail Demand-Related Recoverable Costs (F)			38,515	38,220	38,472	38,574	38,585	38,479	38,373	38,266	38,160	38,055	37,948	37,842	459,490
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$38,515	$38,220	$38,472	$38,574	$38,585	$38,479	$38,373	$38,266	$38,160	$38,055	$37,948	$37,842	$459,490

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) Depreciation calculated in Pipeline Integrity Management section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Lines 2 x 89% @ .008313 x 1/12 + 11%@ .007299 x 1/12. Ratio from Property Tax Administration Department, based on plant allocation reported and 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009

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 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	End of Period Total
1	Investments															
	a. Expenditures/Additions			$625,159	$161,761	$118,706	$166,669	$40,105	$90,116	$10,005	$310,000	$25,000	$80,000	$265,000	$150,000	$2,042,521
	b. Clearings to Plant			5,180	9,882	11,146	1,682	2,934,831	344,696	5	-	-	-	-	-	
	c. Retirements			-	-	-	-	-	-	-	-	-	-	-	-	
	d. Other (A)			-	-	-	-	(18,099)	-	-	-	-	-	-	-	
2	Plant-in-Service/Depreciation Base		$5,267,973	5,273,153	5,283,034	5,294,181	5,295,863	8,230,694	8,575,390	8,575,395	8,575,395	8,575,395	8,575,395	8,575,395	8,575,395	
3	Less: Accumulated Depreciation		(276,408)	(289,476)	(302,564)	(315,674)	(328,787)	(344,574)	(363,834)	(383,892)	(403,950)	(424,008)	(444,066)	(464,124)	(484,182)	
4	CWIP - Non-Interest Bearing		2,158,040	2,778,019	2,929,899	3,037,458	3,202,445	289,620	35,039	45,039	355,039	380,039	460,039	725,039	875,039	
5	Net Investment (Lines 2 + 3 + 4)		7,149,605	7,761,696	7,910,369	8,015,965	8,169,521	8,175,740	8,246,595	8,236,542	8,526,484	8,531,426	8,591,368	8,836,310	8,966,252	
6	Average Net Investment			7,455,651	7,836,033	7,963,167	8,092,743	8,172,630	8,211,167	8,241,568	8,381,513	8,528,955	8,561,397	8,713,839	8,901,281	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		69,337	72,876	74,058	75,263	76,006	76,364	76,647	77,946	79,318	79,622	81,038	82,761	921,258
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		12,676	13,321	13,537	13,757	13,894	13,959	14,010	14,247	14,499	14,554	14,814	15,131	168,399
	c. Other			-	-	-	-	-	-	-	-	-	-	-	-	-
8	Investment Expenses															
	a. Depreciation (C)			13,068	13,088	13,110	13,113	15,787	19,260	20,058	20,058	20,058	20,058	20,058	20,058	207,774
	b. Amortization			-	-	-	-	-	-	-	-	-	-	-	-	-
	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)			3,776	3,784	3,792	3,794	6,061	6,324	6,324	6,324	6,324	6,324	6,324	6,324	65,475
	e. Other			-	-	-	-	-	-	-	-	-	-	-	-	-
9	Total System Recoverable Expenses (Lines 7 + 8)			98,857	103,069	104,497	105,927	111,749	115,907	117,039	118,577	120,199	120,558	122,234	124,294	1,362,907
	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			98,857	103,069	104,497	105,927	111,749	115,907	117,039	118,577	120,199	120,558	122,234	124,294	1,362,907
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
13	Retail Demand-Related Recoverable Costs (F)			87,962	91,710	92,980	94,253	99,433	103,133	104,140	105,509	106,952	107,271	108,763	110,596	1,212,701
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$87,962	$91,710	$92,980	$94,253	$99,433	$103,133	$104,140	$105,509	$106,952	$107,271	$108,763	$110,596	$1,212,701

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) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009

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 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$166,822	$34	$0	$0	$0	$0	$0	$0	$0	$0	$0	$166,856
	b. Clearings to Plant			-	166,822	34	-	-	-	-	-	-	-	-	-	
	c. Retirements			-	-	-	-	-	-	-	-	-	-	-	-	
	d. Other (A)			-	-	-	-	-	-	-	-	-	-	-	-	
2	Plant-in-Service/Depreciation Base		$1,901,933	1,901,933	2,068,756	2,068,790	2,068,790	2,068,790	2,068,790	2,068,790	2,068,790	2,068,790	2,068,790	2,068,790	2,068,790	
3	Less: Accumulated Depreciation		(9,419)	(13,937)	(18,849)	(23,761)	(28,673)	(33,585)	(38,497)	(43,409)	(48,321)	(53,233)	(58,145)	(63,057)	(67,969)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		1,892,515	1,887,997	2,049,907	2,045,029	2,040,117	2,035,205	2,030,293	2,025,381	2,020,469	2,015,557	2,010,645	2,005,733	2,000,821	
6	Average Net Investment			1,890,256	1,968,952	2,047,468	2,042,573	2,037,661	2,032,749	2,027,837	2,022,925	2,018,013	2,013,101	2,008,189	2,003,277	24,113,004
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		17,579	18,311	19,041	18,996	18,950	18,905	18,859	18,813	18,768	18,722	18,676	18,631	224,251
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		3,214	3,348	3,481	3,472	3,464	3,456	3,448	3,439	3,430	3,422	3,414	3,406	40,994
	c. Other			-	-	-	-	-	-	-	-	-	-	-	-	0
8	Investment Expenses															
	a. Depreciation (C)			4,518	4,912	4,912	4,912	4,912	4,912	4,912	4,912	4,912	4,912	4,912	4,912	58,550
	b. Amortization			-	-	-	-	-	-	-	-	-	-	-	-	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)			1,661	1,807	1,807	1,807	1,807	1,807	1,807	1,807	1,807	1,807	1,807	1,807	21,538
	e. Other			-	-	-	-	-	-	-	-	-	-	-	-	0
9	Total System Recoverable Expenses (Lines 7 + 8)			26,972	28,378	29,241	29,187	29,133	29,080	29,026	28,971	28,917	28,863	28,809	28,756	345,333
	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			26,972	28,378	29,241	29,187	29,133	29,080	29,026	28,971	28,917	28,863	28,809	28,756	345,333
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
13	Retail Demand-Related Recoverable Costs (F)			25,287	26,605	27,414	27,364	27,313	27,263	27,213	27,161	27,111	27,060	27,009	26,960	323,760
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$25,287	$26,605	$27,414	$27,364	$27,313	$27,263	$27,213	$27,161	$27,111	$27,060	$27,009	$26,960	$323,760

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) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009

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 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	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			-	-	-	-	-	-	-	-	-	-	-	-	
	c. Retirements			-	-	-	-	-	-	-	-	-	-	-	-	
	d. Other (A)			-	-	-	-	-	-	-	-	-	-	-	-	
2	Plant-in-Service/Depreciation Base		$290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	
3	Less: Accumulated Depreciation		(12,522)	(13,330)	(14,138)	(14,946)	(15,754)	(16,562)	(17,370)	(18,178)	(18,986)	(19,794)	(20,602)	(21,410)	(22,218)	
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)		277,776	276,968	276,160	275,352	274,544	273,736	272,928	272,120	271,312	270,504	269,696	268,888	268,080	
6	Average Net Investment			277,372	276,564	275,756	274,948	274,140	273,332	272,524	271,716	270,908	270,100	269,292	268,484	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		2,580	2,572	2,565	2,557	2,550	2,542	2,534	2,527	2,519	2,512	2,504	2,497	30,459
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		472	470	469	467	466	465	463	462	461	459	458	456	5,568
	c. Other			-	-	-	-	-	-	-	-	-	-	-	-	-
8	Investment Expenses															
	a. Depreciation (C)			808	808	808	808	808	808	808	808	808	808	808	808	9,696
	b. Amortization			-	-	-	-	-	-	-	-	-	-	-	-	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)			172	172	172	172	172	172	172	172	172	172	172	172	2,064
	e. Other			-	0	0	0	0	0		0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			4,032	4,022	4,014	4,004	3,996	3,987	3,977	3,969	3,960	3,951	3,942	3,933	47,787
	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			4,032	4,022	4,014	4,004	3,996	3,987	3,977	3,969	3,960	3,951	3,942	3,933	47,787
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)			3,187	3,179	3,173	3,165	3,159	3,152	3,144	3,137	3,130	3,123	3,116	3,109	37,774
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$3,187	$3,179	$3,173	$3,165	$3,159	$3,152	$3,144	$3,137	$3,130	$3,123	$3,116	$3,109	$37,774

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) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009

Schedule of Amortization and Return
Deferred Gain on Sales of Emissions Allowances (Project 5)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual January 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	End of Period Total
1	Working Capital Dr (Cr)															
	a. 1581001 SO_2 Emission Allowance Inventory		$11,191,196	$10,756,806	$10,416,782	$10,103,171	$9,810,743	$9,478,854	$9,110,149	$8,722,409	$8,277,816	$7,857,535	$7,461,599	$7,162,229	$6,902,143	$6,902,143
	b. 25401FL Auctioned SO_2 Allowance		(2,063,254)	(2,051,459)	(2,039,664)	(2,027,869)	(2,016,074)	(2,085,825)	(2,062,381)	(2,038,936)	(2,015,491)	(1,992,047)	(1,968,602)	(1,945,158)	(1,921,713)	(1,921,713)
	c. 1581002 NOX Emission Allowance Inventory		65,510,820	64,855,450	66,103,726	64,429,120	61,869,163	57,415,302	53,521,483	$48,643,241	$43,268,337	$38,528,993	$34,912,474	$31,552,600	$28,412,468	28,412,468
2	Total Working Capital		$74,638,763	73,560,797	74,480,844	72,504,423	69,663,832	64,808,331	60,569,251	55,326,714	49,530,662	44,394,481	40,405,470	36,769,671	33,392,897	33,392,897
3	Average Net Investment			74,099,780	74,020,821	73,492,634	71,084,127	67,236,081	62,688,791	57,947,983	52,428,688	46,962,572	42,399,976	38,587,570	35,081,284	
4	Return on Average Net Working Capital Balance															
	a. Equity Component Grossed Up For Taxes (A)	11.16%		689,128	688,394	683,481	661,082	625,296	583,006	538,916	487,587	436,752	394,320	358,864	326,256	$6,473,082
	b. Debt Component (Line 3 x 2.04% x 1/12)	2.04%		125,970	125,835	124,937	120,843	114,301	106,571	98,512	89,129	79,836	72,080	65,599	59,638	1,183,252
5	Total Return Component (B)			815,098	814,229	808,419	781,925	739,597	689,577	637,428	576,716	516,588	466,400	424,463	385,894	7,656,333
6	Expense Dr (Cr)															
	a. 5090001 SO_2 allowance expense			434,390	340,024	313,610	292,429	331,889	368,705	$387,741	$444,592	$420,281	$395,937	$299,370	$260,086	4,289,054
	b. 4074004 Amortization Expense			($11,795)	($11,795)	($11,795)	($11,795)	($61,868)	($23,445)	($23,445)	($23,445)	($23,445)	($23,445)	($23,445)	($23,445)	($273,159)
	c. 5090003 NOx Allowance Expense			$3,994,120	3,668,223	3,246,107	2,889,957	4,455,861	5,252,069	$4,878,241	$5,374,904	$4,739,344	$3,616,519	$3,359,874	$3,140,132	$48,615,352
	d. Other			$0	0	0	0	0	6,250	$0	$0	$0	$0	$0	$0	$6,250
7	Net Expense (C)			4,416,716	3,996,452	3,547,922	3,170,590	4,725,882	5,603,579	5,242,537	5,796,052	5,136,181	3,989,011	3,635,800	3,376,773	52,637,496
8	Total System Recoverable Expenses (Lines 5 + 7)			5,231,813	4,810,681	4,356,341	3,952,516	5,465,479	6,293,156	5,879,965	6,372,768	5,652,769	4,455,411	4,060,263	3,762,667	60,293,830
	a. Recoverable costs allocated to Energy			5,231,813	4,810,681	4,356,341	3,952,516	5,465,479	6,293,156	5,879,965	6,372,768	5,652,769	4,455,411	4,060,263	3,762,667	60,293,830
	b. Recoverable costs allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor			0.96780	0.96220	0.96630	0.96650	0.96780	0.96960	0.96030	0.95790	0.95750	0.95620	0.95590	0.95990	
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)			5,063,349	4,628,838	4,209,533	3,820,106	5,289,491	6,101,844	5,646,530	6,104,474	5,412,526	4,260,264	3,881,205	3,611,784	58,029,945
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)			$ 5,063,349	$ 4,628,838	$ 4,209,533	$ 3,820,106	$ 5,289,491	$ 6,101,844	$ 5,646,530	$ 6,104,474	$ 5,412,526	$ 4,260,264	$ 3,881,205	$ 3,611,784	$ 58,029,945

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 2009 through December 2009

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	Actual January 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	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 2.57% x 1/12) 2.04%		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
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) 0.007299		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 (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)		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 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009

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	Actual January 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	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		$1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	
3	Less: Accumulated Depreciation		(47,164)	(50,819)	(54,474)	(58,129)	(61,784)	(65,439)	(69,094)	(72,749)	(76,404)	(80,059)	(83,714)	(87,369)	(91,024)	
4	CWIP - Non-Interest Bearing		(0)	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$1,887,236	1,883,582	1,879,927	1,876,272	1,872,617	1,868,962	1,865,307	1,861,652	1,857,997	1,854,342	1,850,687	1,847,032	1,843,377	
6	Average Net Investment			1,885,409	1,881,754	1,878,099	1,874,444	1,870,789	1,867,134	1,863,479	1,859,824	1,856,169	1,852,514	1,848,859	1,845,204	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		17,535	17,500	17,467	17,433	17,397	17,364	17,331	17,296	17,262	17,228	17,194	17,161	208,168
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		3,206	3,199	3,194	3,186	3,181	3,174	3,168	3,162	3,156	3,149	3,143	3,136	38,054
	c. Other			-	-	-	-	-	-	-	-	-	-	-	-	0
8	Investment Expenses															
	a. Depreciation (C)			3,655	3,655	3,655	3,655	3,655	3,655	3,655	3,655	3,655	3,655	3,655	3,655	43,860
	b. Amortization			-	-	-	-	-	-	-	-	-	-	-	-	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)			1,388	1,388	1,388	1,388	1,388	1,388	1,388	1,388	1,388	1,388	1,388	1,388	16,656
	e. Other			-	-	-	-	-	-	-	-	-	-	-	-	0
9	Total System Recoverable Expenses (Lines 7 + 8)			25,784	25,742	25,704	25,662	25,621	25,581	25,542	25,501	25,461	25,420	25,380	25,340	306,738
	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			25,784	25,742	25,704	25,662	25,621	25,581	25,542	25,501	25,461	25,420	25,380	25,340	306,738
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)			22,942	22,905	22,871	22,834	22,797	22,762	22,727	22,691	22,655	22,618	22,583	22,547	272,932
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$22,942	$22,905	$22,871	$22,834	$22,797	$22,762	$22,727	$22,691	$22,655	$22,618	$22,583	$22,547	$272,932

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) Depreciation calculated in CAIR CTs section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Property tax calculated in CAIR CTs section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: CAMR - Crystal River - Base (Project 7.3 - Continuous Mercury Monitoring Systems)
(in Dollars)

Line Description	Beginning of Period Amount	Actual January 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	End of Period Total
1 Investments														
a. Expenditures/Additions		$243	$1,094	$200	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,538
b. Clearings to Plant		0	0	0	0	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	287,569	287,812	288,907	289,106	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	
5 Net Investment (Lines 2 + 3 + 4)	$287,569	287,812	288,907	289,106	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	
6 Average Net Investment		287,691	288,360	289,007	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	
7 Return on Average Net Investment														
a. Equity Component Grossed Up For Taxes (B) 11.16%		2,676	2,682	2,688	2,689	2,689	2,689	2,689	2,689	2,689	2,689	2,689	2,689	$32,243
b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		489	490	491	491	491	491	491	491	491	491	491	491	5,894
c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
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) 0.010707		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)		3,165	3,172	3,179	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	38,137
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		3,165	3,172	3,179	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	38,137
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)		2,967	2,974	2,980	2,982	2,982	2,982	2,982	2,982	2,982	2,982	2,982	2,982	35,755
14 Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$2,967	$2,974	$2,980	$2,982	$2,982	$2,982	$2,982	$2,982	$2,982	$2,982	$2,982	$2,982	$35,755

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 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009

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	Actual January 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	End of Period Total
1	Investments															
	a. Expenditures/Additions			$26,212,349	$27,108,153	$23,020,640	$22,851,091	$16,544,690	$17,360,816	14,749,560	15,480,095	8,538,220	12,931,151	15,519,896	15,456,092	$215,772,754
	b. Clearings to Plant			1,596,194	82,031	(672,773)	64,021	3,030,400	91,324,148	70,480,087	465,714	44,167	20,833	20,833	769,456,210	
	c. Retirements			-	-	-	-	-	-	-	-	-	-	-	-	
	d. Other (A)	8.848%		5,541,202	5,796,238	6,022,014	6,242,666	6,438,213	6,127,257	6,091,140	6,227,289	6,332,845	6,406,644	6,483,057	1,372,262	69,080,828
2	Plant-in-Service/Depreciation Base		$21,762,083	23,358,277	23,440,309	22,767,536	22,831,557	25,861,957	117,186,105	187,666,192	188,131,906	188,176,073	188,196,906	188,217,739	957,673,949	
3	Less: Accumulated Depreciation		(341,009)	(403,639)	(466,498)	(527,397)	(588,470)	(656,690)	(832,656)	(1,200,122)	(1,651,029)	(2,102,040)	(2,553,100)	(3,004,209)	(4,362,660)	
4	CWIP - AFUDC-Interest Bearing		869,261,457	899,418,815	932,241,174	961,956,601	990,986,337	1,010,938,840	943,102,765	893,463,378	914,705,048	929,531,946	948,848,908	970,831,029	218,203,174	284,853,582
5	Net Investment (Lines 2 + 3 + 4)		890,682,532	922,373,453	955,214,985	984,196,740	1,013,229,424	1,036,144,107	1,059,456,215	1,079,929,448	1,101,185,925	1,115,605,979	1,134,492,714	1,156,044,559	1,171,514,463	
6	Average Net Investment			906,527,992	938,794,219	969,705,862	998,713,082	1,024,686,766	1,047,800,161	1,069,692,831	1,090,557,687	1,108,395,952	1,125,049,347	1,145,268,637	1,163,779,511	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		206,347	213,567	210,245	206,847	220,635	658,247	1,408,110	1,734,203	1,732,380	1,728,487	1,724,486	5,298,455	15,342,009
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		37,719	39,039	38,432	37,811	40,331	120,324	257,396	317,006	316,672	315,961	315,228	968,535	2,804,454
	c. Other			-	-	-	-	-	-	-	-	-	-	-	-	-
8	Investment Expenses															
	a. Depreciation (C)			62,630	62,859	60,899	61,073	68,220	175,966	367,466	450,907	451,011	451,060	451,109	1,359,546	4,022,746
	b. Amortization			-	-	-	-	-	-	-	-	-	-	-	-	-
	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)			20,399	20,471	19,884	19,939	22,586	102,342	163,895	164,302	164,340	164,358	164,377	837,181	1,864,074
	e. Other			-	-	-	-	-	-	-	-	-	-	-	-	-
9	Total System Recoverable Expenses (Lines 7 + 8)			327,095	335,936	329,460	325,670	351,772	1,056,879	2,196,867	2,666,418	2,664,403	2,659,866	2,655,200	8,463,717	24,033,283
	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			327,095	335,936	329,460	325,670	351,772	1,056,879	2,196,867	2,666,418	2,664,403	2,659,866	2,655,200	8,463,717	24,033,283
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			306,661	314,950	308,879	305,325	329,797	990,856	2,059,629	2,499,847	2,497,958	2,493,704	2,489,330	7,934,989	22,531,924
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$306,661	$314,950	$308,879	$305,325	$329,797	$990,856	$2,059,629	$2,499,847	$2,497,958	$2,493,704	$2,489,330	$7,934,989	$22,531,924

Notes:
(A) AFUDC calculation based on 2005 Rate Case Settlement in Dkt. 050078-EI.
(B) Return on equity and debt calculated only on assets placed in service which appear in CAIR Crystal River AFUDC section of Capital Program Detail file. Calculated on that schedule as Line 6 x rate x 1/12. Rate 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) Depreciation calculated only on assets placed inservice which appear in CAIR Crystal River AFUDC section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Rate based on Exhibit 2 in the 2005 rate case settlement in Dkt. 050078-EI.
(D) Property taxes calculated only on assets placed in service which appear in CAIR Crystal River AFUDC section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009

Schedule of Amortization and Return
For Project: CAIR/CAMR - Base - AFUDC (Project 7.4 - Reagents and By-products)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	End of Period Total
1	Working Capital Dr (Cr)															
	a. 1544001 Ammonia Inventory		$0	$0	$0	$0	$0	$0	$0	$158,148	$158,148	$158,148	$158,148	$158,148	$158,148	$158,148
	b. 1544004 Limestone Inventory		0	0	0	0	0	0	0	0	0	285,000	570,000	570,000	570,000	570,000
2	Total Working Capital		$0	0	0	0	0	0	0	158,148	158,148	443,148	728,148	728,148	728,148	728,148
3	Average Net Investment			0	0	0	0	0	0	79,074	158,148	300,648	585,648	728,148	728,148	
4	Return on Average Net Working Capital Balance															
	a. Equity Component Grossed Up For Taxes (A)	11.16%		0	0	0	0	0	0	735	1,471	2,796	5,447	6,772	6,772	$23,992
	b. Debt Component (Line 3 x 2.04% x 1/12)	2.04%		0	0	0	0	0	0	134	269	511	996	1,238	1,238	4,386
5	Total Return Component (B)			0	0	0	0	0	0	870	1,740	3,307	6,442	8,010	8,010	28,378
6	Expense Dr (Cr)															
	a. 5020011 Ammonia expense			0	0	0	0	0	0	221,096	241,714	237,897	255,057	16,481	227,374	1,199,619
	c. 5020012 Limestone Expense			0	0	0	0	0	0	0	0	0	0	0	48,296	48,296
	d. 5020003 Gypsum Disposal/Sale			0	0	0		0	0	0	0	0	0	0	139,505	139,505
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
7	Net Expense (C)			0	0	0	0	0	0	221,096	241,714	237,897	255,057	16,481	415,175	1,387,420
8	Total System Recoverable Expenses (Lines 5 + 7)			0	0	0	0	0	0	221,966	243,454	241,204	261,499	24,491	423,185	1,415,798
	a. Recoverable costs allocated to Energy			0	0	0	0	0	0	221,966	243,454	241,204	261,499	24,491	423,185	1,415,798
	b. Recoverable costs allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor			0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	0.93753	
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)			0	0	0	0	0	0	208,099	228,245	226,136	245,163	22,961	396,749	1,327,353
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)			$ -	$ -	$ -	$ -	$ -	$ -	$ 208,099	$ 228,245	$ 226,136	$ 245,163	$ 22,961	$ 396,749	$ 1,327,353

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 2009 through December 2009

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 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$3,333	$3,333	$3,333	$3,333	$3,333	$3,333	$20,000
	b. Clearings to Plant		0	0	0	0	0	0	0	0	10,000	-	-	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	$10,146	10,146	10,146	10,146	10,146	10,146	10,146	10,146	10,146	20,146	20,146	20,146	30,146	
3	Less: Accumulated Depreciation	(232)	(271)	(310)	(349)	(388)	(427)	(466)	(505)	(544)	(602)	(679)	(756)	(852)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	3,333	6,667	0	3,333	6,667	0	
5	Net Investment (Lines 2 + 3 + 4)	$9,914	9,875	9,836	9,797	9,758	9,719	9,680	12,974	16,269	19,544	22,800	26,057	29,294	
6	Average Net Investment		9,895	9,856	9,817	9,778	9,739	9,700	11,327	14,622	17,906	21,172	24,429	27,675	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		92	92	91	91	91	90	105	136	167	197	227	257	$1,636
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		17	17	17	17	17	16	19	25	30	36	42	47	299
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation (C) 4.59%		39	39	39	39	39	39	39	39	58	77	77	96	620
	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) 0.009400		8	8	8	8	8	8	8	8	16	16	16	24	136
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		156	155	155	155	154	154	172	208	271	326	362	424	2,691
	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		156	155	155	155	154	154	172	208	271	326	362	424	2,691
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)		155	155	154	154	154	153	171	207	270	325	360	423	2,680
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$155	$155	$154	$154	$154	$153	$171	$207	$270	$325	$360	$423	$2,680

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 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. ___ (TGF-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009

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 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	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	(8,512)	(8,972)	(9,432)	(9,892)	(10,352)	(10,812)	(11,272)	(11,732)	(12,192)	(12,652)	(13,112)	(13,572)	(14,032)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$160,429	159,969	159,509	159,049	158,589	158,129	157,669	157,209	156,749	156,289	155,829	155,369	154,909	
6	Average Net Investment		160,199	159,739	159,279	158,819	158,359	157,899	157,439	156,979	156,519	156,059	155,599	155,139	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		1,490	1,486	1,481	1,477	1,473	1,468	1,464	1,460	1,456	1,451	1,447	1,443	$17,596
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		272	272	271	270	269	268	268	267	266	265	265	264	3,216
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation (C) 3.27%		460	460	460	460	460	460	460	460	460	460	460	460	5,520
	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) 0.010480		148	148	148	148	148	148	148	148	148	148	148	148	1,776
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,370	2,365	2,360	2,355	2,350	2,345	2,340	2,335	2,330	2,325	2,320	2,315	28,108
	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		2,370	2,365	2,360	2,355	2,350	2,345	2,340	2,335	2,330	2,325	2,320	2,315	28,108
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)		2,222	2,217	2,213	2,208	2,203	2,198	2,194	2,189	2,184	2,179	2,175	2,170	26,352
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$2,222	$2,217	$2,213	$2,208	$2,203	$2,198	$2,194	$2,189	$2,184	$2,179	$2,175	$2,170	$26,352

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 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009

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 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	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	$76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	
3	Less: Accumulated Depreciation	(4,745)	(4,947)	(5,149)	(5,351)	(5,553)	(5,755)	(5,957)	(6,159)	(6,361)	(6,563)	(6,765)	(6,967)	(7,169)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$71,261	71,059	70,857	70,655	70,453	70,251	70,049	69,847	69,645	69,443	69,241	69,039	68,837	
6	Average Net Investment		71,160	70,958	70,756	70,554	70,352	70,150	69,948	69,746	69,544	69,342	69,140	68,938	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 11.16%		662	660	658	656	654	652	651	649	647	645	643	641	$7,817
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		121	121	120	120	120	119	119	119	118	118	118	117	1,429
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation (C) 3.19%		202	202	202	202	202	202	202	202	202	202	202	202	2,424
	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) 0.009130		58	58	58	58	58	58	58	58	58	58	58	58	696
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,043	1,041	1,038	1,036	1,034	1,032	1,029	1,027	1,025	1,023	1,021	1,018	12,366
	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		1,043	1,041	1,038	1,036	1,034	1,032	1,029	1,027	1,025	1,023	1,021	1,018	12,366
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)		824	823	821	819	817	815	814	812	810	808	807	805	9,775
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$824	$823	$821	$819	$817	$815	$814	$812	$810	$808	$807	$805	$9,775

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 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009

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 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	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		$665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	
3	Less: Accumulated Depreciation		(324,147)	(335,233)	(346,319)	(357,405)	(368,491)	(379,577)	(390,663)	(401,749)	(412,835)	(423,921)	(435,007)	(446,093)	(457,179)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$340,994	329,908	318,822	307,736	296,650	285,564	274,478	263,392	252,306	241,220	230,134	219,048	207,962	
6	Average Net Investment			335,451	324,365	313,279	302,193	291,107	280,021	268,935	257,849	246,763	235,677	224,591	213,505	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	11.16%		3,120	3,017	2,913	2,810	2,707	2,604	2,501	2,398	2,295	2,192	2,089	1,986	$30,632
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		570	551	533	514	495	476	457	438	419	401	382	363	5,599
	c. Other (G)			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C) 20.00%			11,086	11,086	11,086	11,086	11,086	11,086	11,086	11,086	11,086	11,086	11,086	11,086	133,032
	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) 0.010480			581	581	581	581	581	581	581	581	581	581	581	581	6,972
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			15,357	15,235	15,113	14,991	14,869	14,747	14,625	14,503	14,381	14,259	14,137	14,016	176,235
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			15,357	15,235	15,113	14,991	14,869	14,747	14,625	14,503	14,381	14,259	14,137	14,016	176,235
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)			14,398	14,283	14,169	14,055	13,940	13,826	13,712	13,597	13,483	13,369	13,254	13,140	165,226
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$14,398	$14,283	$14,169	$14,055	$13,940	$13,826	$13,712	$13,597	$13,483	$13,369	$13,254	$13,140	$165,226

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 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Progress Energy Florida
Witness: T.G. Foster
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2009 through December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Crystal River Thermal Discharge Compliance Project - AFUDC - Base (Project 11.1)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual January 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	End of Period Total
1	Investments															
	a. Expenditures/Additions			$10,944	$5,686	$116,839	$801,002	$118,007	$348,477	$2,846,056	$2,460,588	$1,023,529	$693,288	$133,548	$601,224	$9,159,188
	b. Clearings to Plant			0	0	0	0	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	2,742	6,155	10,645	16,140	27,967	46,978	59,662	66,171	69,571	72,669	378,700
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	10,944	16,630	136,212	943,369	1,072,021	1,436,638	4,310,661	6,818,226	7,901,417	8,660,876	8,863,995	9,537,888	
5	Net Investment (Lines 2 + 3 + 4)		$0	10,944	16,630	136,212	943,369	1,072,021	1,436,638	4,310,661	6,818,226	7,901,417	8,660,876	8,863,995	9,537,888	
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
	c. Other (G)			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	20.00%		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)	0.010480		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 (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) AFUDC calculation based on 2005 Rate Case Settlement in Dkt. 050078-EI.
(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 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. __ (TGF-1)

Form 42-8E Appendix

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2009 through December 2009

Variance Report of Capital Investment Activities
(In Dollars)

Line		(1) Estimated/ Actual	(2) Original Projection	(3) Variance Amount	(4) Variance Percent
1	Description of Investment Projects				
	3 Pipeline Integrity Management - Bartow/Anclote Pipeline-Intermediate	($78,151)	$60,000	($138,151)	-230%
	4.1 Above Ground Tank Secondary Containment - Peaking	2,042,521	1,337,000	705,521	53%
	4.2 Above Ground Tank Secondary Containment - Base	166,856	-	166,856	100%
	4.3 Above Ground Tank Secondary Containment - Intermediate	-	-	-	
	5 SO2/NOX Emissions Allowances - Energy (A)	33,392,897	32,394,756	998,142	3%
	7.1 CAIR/CAMR Anclote- Intermediate	-	-	-	N/A
	7.2 CAIR CT's - Peaking	-	-	-	N/A
	7.3 CAMR Crystal River - Base	1,538	-	1,538	100%
	7.4 CAIR/CAMR Crystal River AFUDC - Base	215,772,754	$215,895,835	(123,081)	0%
	9 Sea Turtle - Coastal Street Lighting -Distribution	20,000	20,000	-	0%
	10.1 Underground Storage Tanks-Base	-	-	-	N/A
	10.2 Underground Storage Tanks-Intermediate	-	-	-	N/A
	11 Modular Cooling Towers - Base	-	-	-	N/A
	11.1 Thermal Discharge Permanent Cooling Tower - Base	9,159,188	$11,599,807	(2,440,619)	-21%
2	Total Investment Projects - Capital Expenditures	260,477,603	261,307,397	(829,794)	0%

Notes:
(A) Working Capital

Witness: T.G. Foster
Exibit__(TGF-2)

PROGRESS ENERGY FLORIDA, INC.
ENVIRONMENTAL COST RECOVERY
CAPITAL PROGRAM DETAIL

JANUARY 2009 - DECEMBER 2009

DOCKET NO. 090007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 25
COMPANY Progress Energy Florida, Inc.
WITNESS Thomas G. Foster (TGF-2)
DATE 11/02/09

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No.__(TGF-2)
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For Project: PIPELINE INTEGRITY MANAGEMENT - Alderman Road Fence (Project 3.1a)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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		$33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	
3 Less: Accumulated Depreciation		(4,453)	(4,540)	(4,627)	(4,714)	(4,801)	(4,888)	(4,975)	(5,062)	(5,149)	(5,236)	(5,323)	(5,410)	(5,497)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$29,500	29,413	29,326	29,239	29,152	29,065	28,978	28,891	28,804	28,717	28,630	28,543	28,456	
6 Average Net Investment			29,456	29,369	29,282	29,195	29,108	29,021	28,934	28,847	28,760	28,673	28,586	28,499	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		274	273	272	272	271	270	269	268	267	267	266	265	$3,234
b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		50	50	50	50	49	49	49	49	49	49	49	48	591
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	3.07%		87	87	87	87	87	87	87	87	87	87	87	87	.1,044
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	0.008201		23	23	23	23	23	23	23	23	23	23	23	23	276
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			434	433	432	432	430	429	428	427	426	426	425	423	5.145
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			434	433	432	432	430	429	428	427	426	426	425	423	5,145

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Leak Detection (Project 3.1b)
(In Dollars)

Line Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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		$2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	
3 Less: Accumulated Depreciation		(413,411)	(422,433)	(431,455)	(440,477)	(449,499)	(458,521)	(467,543)	(476,565)	(485,587)	(494,609)	(503,631)	(512,653)	(521,675)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$2,227,225	2,218,203	2,209,181	2,200,159	2,191,137	2,182,115	2,173,093	2,164,071	2,155,049	2,146,027	2,137,005	2,127,983	2,118,961	
6 Average Net Investment			2,222,714	2,213,692	2,204,670	2,195,648	2,186,626	2,177,604	2,168,582	2,159,560	2,150,538	2,141,516	2,132,494	2,123,472	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		20,671	20,587	20,503	20,420	20,336	20,252	20,168	20,084	20,000	19,916	19,832	19,748	$242,517
b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		3,779	3,763	3,748	3,733	3,717	3,702	3,687	3,671	3,656	3,641	3,625	3,610	44,332
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	4.10%		9,022	9,022	9,022	9,022	9,022	9,022	9,022	9,022	9,022	9,022	9,022	9,022	108,264
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	0.008201		1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	21,660
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			35,277	35,177	35,078	34,980	34,880	34,781	34,682	34,582	34,483	34,384	34,284	34,185	416,773
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			35,277	35,177	35,078	34,980	34,880	34,781	34,682	34,582	34,483	34,384	34,284	34,185	416,773

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For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Controls Upgrade (Project 3.1c)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1	Investments															
	a. Expenditures/Additions			($187,531)	$82,276	$0	$27,105	$0	$0	$0	$0	$0	$0	$0	$0	($78,151)
	b. Clearings to Plant			(187,531)	82,276	0	27,105	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		$983,298	795,767	878,043	878,043	905,147	905,147	905,147	905,147	905,147	905,147	905,147	905,147	905,147	
3	Less: Accumulated Depreciation		(1,680)	(4,399)	(7,399)	(10,399)	(13,492)	(16,585)	(19,678)	(22,771)	(25,864)	(28,957)	(32,050)	(35,143)	(38,236)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$981,618	791,368	870,643	867,643	891,655	888,562	885,469	882,376	879,283	876,190	873,097	870,004	866,911	
6	Average Net Investment			886,493	831,005	869,143	879,649	890,109	887,016	883,923	880,830	877,737	874,644	871,551	868,458	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		8,244	7,728	8,083	8,181	8,278	8,249	8,220	8,192	8,163	8,134	8,105	8,077	$97,654
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		1,507	1,413	1,478	1,495	1,513	1,508	1,503	1,497	1,492	1,487	1,482	1,476	17,851
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	4.10%		2,719	3,000	3,000	3,093	3,093	3,093	3,093	3,093	3,093	3,093	3,093	3,093	36,556
	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	0.008201		544	600	600	619	619	619	619	619	619	619	619	619	7,315
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			13,014	12,741	13,161	13,388	13,503	13,469	13,435	13,401	13,367	13,333	13,299	13,265	159,376
	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			13,014	12,741	13,161	13,388	13,503	13,469	13,435	13,401	13,367	13,333	13,299	13,265	159,376

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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2009 through December 2009
Pipline Intergrity Management (Project 3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - TURNER CTs (Project 4.1a)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1	Investments															
	a. Expenditures/Additions			$241,385	$45,946	$102,360	$34,750	$0	$190	$0	$0	$0	$0	$0	$0	$424,631
	b. Clearings to Plant			0	0	0	0	903,126	190	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	(18,099)	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$1,051,183	1,051,183	1,051,183	1,051,183	1,051,183	1,954,309	1,954,499	1,954,499	1,954,499	1,954,499	1,954,499	1,954,499	1,954,499	
3	Less: Accumulated Depreciation		(5,658)	(7,291)	(8,924)	(10,557)	(12,190)	(14,524)	(17,560)	(20,596)	(23,632)	(26,668)	(29,704)	(32,740)	(35,776)	
4	CWIP - Non-Interest Bearing		496,784	738,169	784,115	886,475	921,225	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$1,542,310	1,782,061	1,826,375	1,927,101	1,960,218	1,939,785	1,936,939	1,933,903	1,930,867	1,927,831	1,924,795	1,921,759	1,918,723	
6	Average Net Investment			1,662,186	1,804,218	1,876,738	1,943,660	1,950,002	1,938,362	1,935,421	1,932,385	1,929,349	1,926,313	1,923,277	1,920,241	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		15,458	16,779	17,454	18,076	18,135	18,027	17,999	17,971	17,943	17,915	17,886	17,858	$211,501
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		2,826	3,067	3,190	3,304	3,315	3,295	3,290	3,285	3,280	3,275	3,270	3,264	38,661
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.86%		1,633	1,633	1,633	1,633	2,335	3,036	3,036	3,036	3,036	3,036	3,036	3,036	30,119
	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	0.009270		812	812	812	812	1,510	1,510	1,510	1,510	1,510	1,510	1,510	1,510	15,328
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			20,729	22,291	23,089	23,825	25,295	25,868	25,835	25,802	25,769	25,736	25,702	25,668	295,609
	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			20,729	22,291	23,089	23,825	25,295	25,868	25,835	25,802	25,769	25,736	25,702	25,668	295,609

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BARTOW CTs (Project 4.1b)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1	Investments															
	a. Expenditures/Additions			$4,994	$4,980	$874	$3,281	$0	$3,586	$10,000	$310,000	$25,000	$80,000	$265,000	$150,000	$857,716
	b. Clearings to Plant			0	0	0	0	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		(30,596)	(31,020)	(31,444)	(31,868)	(32,292)	(32,716)	(33,140)	(33,564)	(33,988)	(34,412)	(34,836)	(35,260)	(35,684)	
4	CWIP - Non-Interest Bearing		17,325	22,319	27,299	28,173	31,454	31,454	35,040	45,040	355,040	380,040	460,040	725,040	875,040	
5	Net Investment (Lines 2 + 3 + 4)		$140,427	144,997	149,553	150,003	152,861	152,437	155,599	165,175	474,751	499,327	578,903	843,479	993,055	
6	Average Net Investment			142,712	147,275	149,778	151,432	152,649	154,018	160,387	319,963	487,039	539,115	711,191	918,267	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		1,327	1,370	1,393	1,408	1,420	1,432	1,492	2,976	4,529	5,014	6,614	8,540	$37,515
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		243	250	255	257	260	262	273	544	828	916	1,209	1,561	6,858
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.31%		424	424	424	424	424	424	424	424	424	424	424	424	5,088
	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	0.009130		117	117	117	117	117	117	117	117	117	117	117	117	1,404
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,111	2,161	2,189	2,206	2,221	2,235	2,306	4,061	5,898	6,471	8,364	10,642	50,865
	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			2,111	2,161	2,189	2,206	2,221	2,235	2,306	4,061	5,898	6,471	8,364	10,642	50,865

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 1 & 2 (Project 4.2)
(in Dollars)

Line Description	Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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	(7,215)	(7,326)	(7,437)	(7,548)	(7,659)	(7,770)	(7,881)	(7,992)	(8,103)	(8,214)	(8,325)	(8,436)	(8,547)	
4 CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)	$25,877	25,766	25,655	25,544	25,433	25,322	25,211	25,100	24,989	24,878	24,767	24,656	24,545	
6 Average Net Investment		25,821	25,710	25,599	25,488	25,377	25,266	25,155	25,044	24,933	24,822	24,711	24,600	
7 Return on Average Net Investment														
a. Equity Component Grossed Up For Taxes 11.16%		240	239	238	237	236	235	234	233	232	231	230	229	$2,814
b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		44	44	44	43	43	43	43	43	42	42	42	42	515
c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses														
a. Depreciation 4.03%		111	111	111	111	111	111	111	111	111	111	111	111	1,332
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 0.010480		29	29	29	29	29	29	29	29	29	29	29	29	348
e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)		424	423	422	420	419	418	417	416	414	413	412	411	5,009
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		424	423	422	420	419	418	417	416	414	413	412	411	5,009

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - INTERCESSION CITY CTs (Project 4.1c)
(in Dollars)

Line Description	Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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	$1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	
3 Less: Accumulated Depreciation	(119,795)	(124,489)	(129,183)	(133,877)	(138,571)	(143,265)	(147,959)	(152,653)	(157,347)	(162,041)	(166,735)	(171,429)	(176,123)	
4 CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)	$1,541,869	1,537,175	1,532,481	1,527,787	1,523,093	1,518,399	1,513,705	1,509,011	1,504,317	1,499,623	1,494,929	1,490,235	1,485,541	
6 Average Net Investment		1,539,522	1,534,828	1,530,134	1,525,440	1,520,746	1,516,052	1,511,358	1,506,664	1,501,970	1,497,276	1,492,582	1,487,888	
7 Return on Average Net Investment														
a. Equity Component Grossed Up For Taxes 11.16%		14,318	14,274	14,230	14,187	14,143	14,099	14,056	14,012	13,968	13,925	13,881	13,837	$168,930
b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		2,617	2,609	2,601	2,593	2,585	2,577	2,569	2,561	2,553	2,545	2,537	2,529	30,876
c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses														
a. Depreciation 3.39%		4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	4,694	56,328
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 0.007740		1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	12,864
e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)		22,701	22,649	22,597	22,546	22,494	22,442	22,391	22,339	22,287	22,236	22,184	22,132	268,998
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		22,701	22,649	22,597	22,546	22,494	22,442	22,391	22,339	22,287	22,236	22,184	22,132	268,998

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - AVON PARK CTs (Project 4.1d)
(in Dollars)

Line Description	Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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	(14,921)	(15,441)	(15,961)	(16,481)	(17,001)	(17,521)	(18,041)	(18,561)	(19,081)	(19,601)	(20,121)	(20,641)	(21,161)	
4 CWIP - Non-Interest Bearing	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5 Net Investment (Lines 2 + 3 + 4)	$164,017	163,497	162,977	162,457	161,937	161,417	160,897	160,377	159,857	159,337	158,817	158,297	157,777	
6 Average Net Investment		163,757	163,237	162,717	162,197	161,677	161,157	160,637	160,117	159,597	159,077	158,557	158,037	
7 Return on Average Net Investment														
a. Equity Component Grossed Up For Taxes 11.16%		1,523	1,518	1,513	1,508	1,504	1,499	1,494	1,489	1,484	1,479	1,475	1,470	$17,956
b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		278	278	277	276	275	274	273	272	271	270	270	269	3,283
c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses														
a. Depreciation 3.49%		520	520	520	520	520	520	520	520	520	520	520	520	6,240
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 0.008760		131	131	131	131	131	131	131	131	131	131	131	131	1,572
e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)		2,452	2,447	2,441	2,435	2,430	2,424	2,418	2,412	2,406	2,400	2,396	2,390	29,051
a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand		2,452	2,447	2,441	2,435	2,430	2,424	2,418	2,412	2,406	2,400	2,396	2,390	29,051

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BAYBORO CTs (Project 4.1e)
(in Dollars)

Line Description	Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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	(285)	0	0	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	$730,580	730,580	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	
3 Less: Accumulated Depreciation	(26,168)	(27,787)	(29,406)	(31,025)	(32,644)	(34,263)	(35,882)	(37,501)	(39,120)	(40,739)	(42,358)	(43,977)	(45,596)	
4 CWIP - Non-Interest Bearing	(285)	(285)	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)	$704,127	702,508	700,889	699,270	697,651	696,032	694,413	692,794	691,175	689,556	687,937	686,318	684,699	
6 Average Net Investment		703,318	701,699	700,080	698,461	696,842	695,223	693,604	691,985	690,366	688,747	687,128	685,509	
7 Return on Average Net Investment														
a. Equity Component Grossed Up For Taxes 11.16%		6,541	6,526	6,511	6,496	6,481	6,466	6,451	6,435	6,420	6,405	6,390	6,375	$77,497
b. Debt Component (Line 6 x 2.57% x 1/12) 2.04%		1,196	1,193	1,190	1,187	1,185	1,182	1,179	1,176	1,174	1,171	1,168	1,165	14,166
c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses														
a. Depreciation 2.66%		1,619	1,619	1,619	1,619	1,619	1,619	1,619	1,619	1,619	1,619	1,619	1,619	19,428
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 0.009130		556	556	556	556	556	556	556	556	556	556	556	556	6,672
e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)		9,912	9,894	9,876	9,858	9,841	9,823	9,805	9,786	9,769	9,751	9,733	9,715	117,763
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		9,912	9,894	9,876	9,858	9,841	9,823	9,805	9,786	9,769	9,751	9,733	9,715	117,763

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. __ (TGF-2)
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For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - SUWANNEE CTs (Project 4.1f)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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		$1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	
3	Less: Accumulated Depreciation		(51,168)	(53,934)	(56,700)	(59,466)	(62,232)	(64,998)	(67,764)	(70,530)	(73,296)	(76,062)	(78,828)	(81,594)	(84,360)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$986,031	983,265	980,499	977,733	974,967	972,201	969,435	966,669	963,903	961,137	958,371	955,605	952,839	
6	Average Net Investment			984,648	981,882	979,116	976,350	973,584	970,818	968,052	965,286	962,520	959,754	956,988	954,222	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		9,157	9,132	9,106	9,080	9,054	9,029	9,003	8,977	8,951	8,926	8,900	8,874	$108,189
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		1,674	1,669	1,664	1,660	1,655	1,650	1,646	1,641	1,636	1,632	1,627	1,622	19,776
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.20%		2,766	2,766	2,766	2,766	2,766	2,766	2,766	2,766	2,766	2,766	2,766	2,766	33,192
	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	0.007850		679	679	679	679	679	679	679	679	679	679	679	679	8,148
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			14,276	14,246	14,215	14,185	14,154	14,124	14,094	14,063	14,032	14,003	13,972	13,941	169,305
	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			14,276	14,246	14,215	14,185	14,154	14,124	14,094	14,063	14,032	14,003	13,972	13,941	169,305

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - DeBARY CTs (Project 4.1g)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1	Investments															
	a. Expenditures/Additions			$378,780	$10,227	$13,121	$13,535	$0	$618	$0	$0	$0	$0	$0	$0	$416,280
	b. Clearings to Plant			5,180	10,167	11,146	1,682	2,031,705	618	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		$313,275	318,455	328,622	339,768	341,450	2,373,155	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	
3	Less: Accumulated Depreciation		(304)	(922)	(1,560)	(2,220)	(2,883)	(5,519)	(10,128)	(14,737)	(19,346)	(23,955)	(28,564)	(33,173)	(37,782)	
4	CWIP - Non-Interest Bearing		1,644,217	2,017,817	2,017,877	2,019,852	2,031,705	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$1,957,188	2,335,350	2,344,939	2,357,400	2,370,272	2,367,636	2,363,645	2,359,036	2,354,427	2,349,818	2,345,209	2,340,600	2,335,991	
6	Average Net Investment			2,146,269	2,340,145	2,351,169	2,363,836	2,368,954	2,365,641	2,361,341	2,356,732	2,352,123	2,347,514	2,342,905	2,338,296	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		19,960	21,763	21,866	21,984	22,031	22,000	21,960	21,918	21,875	21,832	21,789	21,746	$260,724
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		3,649	3,978	3,997	4,019	4,027	4,022	4,014	4,006	3,999	3,991	3,983	3,975	47,660
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.33%		618	638	660	663	2,636	4,609	4,609	4,609	4,609	4,609	4,609	4,609	37,478
	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	0.009270		246	254	262	264	1,833	1,834	1,834	1,834	1,834	1,834	1,834	1,834	15,697
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			24,473	26,633	26,785	26,930	30,527	32,465	32,417	32,367	32,317	32,266	32,215	32,164	361,559
	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			24,473	26,633	26,785	26,930	30,527	32,465	32,417	32,367	32,317	32,266	32,215	32,164	[illegible]

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. __ (TGF-2)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2009 through December 2009
Pipline Intergrity Management (Project 3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - University of Florida (Project 4.1h)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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		(27,798)	(28,592)	(29,386)	(30,180)	(30,974)	(31,768)	(32,562)	(33,356)	(34,150)	(34,944)	(35,738)	(36,532)	(37,326)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$113,636	112,842	112,048	111,254	110,460	109,666	108,872	108,078	107,284	106,490	105,696	104,902	104,108	
6	Average Net Investment			113,239	112,445	111,651	110,857	110,063	109,269	108,475	107,681	106,887	106,093	105,299	104,505	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		1,053	1,046	1,038	1,031	1,024	1,016	1,009	1,001	994	987	979	972	$12,150
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		193	191	190	188	187	186	184	183	182	180	179	178	2,221
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	6.74%		794	794	794	794	794	794	794	794	794	794	794	794	9,528
	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	0.013790		163	163	163	163	163	163	163	163	163	163	163	163	1,956
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,203	2,194	2,185	2,176	2,168	2,159	2,150	2,141	2,133	2,124	2,115	2,107	25,855
	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			2,203	2,194	2,185	2,176	2,168	2,159	2,150	2,141	2,133	2,124	2,115	2,107	25,855

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Anclote (Project 4.3)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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		$290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	
3	Less: Accumulated Depreciation		($12,522)	(13,330)	(14,138)	(14,946)	(15,754)	(16,562)	(17,370)	(18,178)	(18,986)	(19,794)	(20,602)	(21,410)	(22,218)	
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)		$277,776	276,968	276,160	275,352	274,544	273,736	272,928	272,120	271,312	270,504	269,696	268,888	268,080	
6	Average Net Investment			277,372	276,564	275,756	274,948	274,140	273,332	272,524	271,716	270,908	270,100	269,292	268,484	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		2,580	2,572	2,565	2,557	2,550	2,542	2,534	2,527	2,519	2,512	2,504	2,497	$30,459
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		472	470	469	467	466	465	463	462	461	459	458	456	5,568
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.34%		808	808	808	808	808	808	808	808	808	808	808	808	9,696
	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	0.007100		172	172	172	172	172	172	172	172	172	172	172	172	2,064
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			4,032	4,022	4,014	4,004	3,996	3,987	3,977	3,969	3,960	3,951	3,942	3,933	47,787
	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			4,032	4,022	4,014	4,004	3,996	3,987	3,977	3,969	3,960	3,951	3,942	3,933	47,787

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Deatil Support - January 2009 through December 2009
Pipline Intergrity Management (Project 3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 4 & 5 (Project 4.2a)
(in Dollars)

Line / Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1 Investments															
a. Expenditures/Additions			$0	$166,822	$34	$0	$0	$0	$0	$0	$0	$0	$0	$0	$166,856
b. Clearings to Plant			0	166,822	34	0	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		$1,868,841	1,868,841	2,035,664	2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	
3 Less: Accumulated Depreciation		(2,204)	(6,611)	(11,412)	(16,213)	(21,014)	(25,815)	(30,616)	(35,417)	(40,218)	(45,019)	(49,820)	(54,621)	(59,422)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$1,866,638	1,862,231	2,024,252	2,019,485	2,014,684	2,009,883	2,005,082	2,000,281	1,995,480	1,990,679	1,985,878	1,981,077	1,976,276	
6 Average Net Investment			1,864,435	1,943,242	2,021,869	2,017,085	2,012,284	2,007,483	2,002,682	1,997,881	1,993,080	1,988,279	1,983,478	1,978,677	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		17,339	18,072	18,803	18,759	18,714	18,670	18,625	18,580	18,536	18,491	18,446	18,402	$221,437
b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		3,170	3,304	3,437	3,429	3,421	3,413	3,405	3,396	3,388	3,380	3,372	3,364	40,479
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	2.83%		4,407	4,801	4,801	4,801	4,801	4,801	4,801	4,801	4,801	4,801	4,801	4,801	57,218
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	0.010480		1,632	1,778	1,778	1,778	1,778	1,778	1,778	1,778	1,778	1,778	1,778	1,778	21,190
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			26,548	27,955	28,819	28,767	28,714	28,662	28,609	28,555	28,503	28,450	28,397	28,345	340,324
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			26,548	27,955	28,819	28,767	28,714	28,662	28,609	28,555	28,503	28,450	28,397	28,345	340,324

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Higgins (Project 4.1i)
(in Dollars)

Line / Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1 Investments															
a. Expenditures/Additions			$0	$100,608	$2,351	$115,103	$40,105	$85,722	$5	$0	$0	$0	$0	$0	$343,894
b. Clearings to Plant			0	0	0	0	0	343,888	5	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	343,888	343,893	343,893	343,893	343,893	343,893	343,893	
3 Less: Accumulated Depreciation		0	0	0	0	0	0	(798)	(2,394)	(3,990)	(5,586)	(7,182)	(8,778)	(10,374)	
4 CWIP - Non-Interest Bearing		0	0	100,608	102,959	218,062	258,167	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5 Net Investment (Lines 2 + 3 + 4)		$0	0	100,608	102,959	218,062	258,167	343,090	341,499	339,903	338,307	336,711	335,115	333,519	
6 Average Net Investment			0	50,304	101,783	160,510	238,114	300,628	342,294	340,701	339,105	337,509	335,913	334,317	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		0	468	947	1,493	2,214	2,796	3,183	3,169	3,154	3,139	3,124	3,109	$26,796
b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		0	86	173	273	405	511	582	579	576	574	571	568	4,898
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	5.57%		0	0	0	0	0	798	1,596	1,596	1,596	1,596	1,596	1,596	10,374
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	0.009130		0	0	0	0	0	262	262	262	262	262	262	262	1,834
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			0	554	1,120	1,766	2,619	4,367	5,623	5,606	5,588	5,571	5,553	5,535	43,902
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	554	1,120	1,766	2,619	4,367	5,623	5,606	5,588	5,571	5,553	5,535	43,902

For Project: CAIR CTs - AVON PARK (Project 7.2a)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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		$161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	
3	Less: Accumulated Depreciation		(2,417)	(2,595)	(2,773)	(2,951)	(3,129)	(3,307)	(3,485)	(3,663)	(3,841)	(4,019)	(4,197)	(4,375)	(4,553)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$159,337	159,159	158,981	158,803	158,625	158,447	158,269	158,091	157,913	157,735	157,557	157,379	157,201	
6	Average Net Investment			159,248	159,070	158,892	158,714	158,536	158,358	158,180	158,002	157,824	157,646	157,468	157,290	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		1,481	1,479	1,478	1,476	1,474	1,473	1,471	1,469	1,468	1,466	1,464	1,463	$17,662
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		271	270	270	270	270	269	269	269	268	268	268	267	3,229
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.32%		178	178	178	178	178	178	178	178	178	178	178	178	2,136
	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	0.008760		118	118	118	118	118	118	118	118	118	118	118	118	1,416
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,048	2,045	2,044	2,042	2,040	2,038	2,036	2,034	2,032	2,030	2,028	2,026	24,443
	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			2,048	2,045	2,044	2,042	2,040	2,038	2,036	2,034	2,032	2,030	2,028	2,026	24,443

For Project: CAIR CTs - BARTOW (Project 7.2b)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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		$275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	
3	Less: Accumulated Depreciation		(10,165)	(10,924)	(11,683)	(12,442)	(13,201)	(13,960)	(14,719)	(15,478)	(16,237)	(16,996)	(17,755)	(18,514)	(19,273)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$265,182	264,423	263,664	262,905	262,146	261,387	260,628	259,869	259,110	258,351	257,592	256,833	256,074	
6	Average Net Investment			264,803	264,044	263,285	262,526	261,767	261,008	260,249	259,490	258,731	257,972	257,213	256,454	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		2,463	2,456	2,449	2,441	2,434	2,427	2,420	2,413	2,406	2,399	2,392	2,385	$29,085
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		450	449	448	446	445	444	442	441	440	439	437	436	5,317
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.31%		759	759	759	759	759	759	759	759	759	759	759	759	9,108
	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	0.009130		209	209	209	209	209	209	209	209	209	209	209	209	2,508
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			3,881	3,873	3,865	3,855	3,847	3,839	3,830	3,822	3,814	3,806	3,797	3,789	46,018
	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			3,881	3,873	3,865	3,855	3,847	3,839	3,830	3,822	3,814	3,806	3,797	3,789	46,018

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Deatil Support - January 2009 through December 2009
Pipline Intergrity Management (Project 3 Recap)

For Project: CAIR CTs - BAYBORO (Project 7.2c)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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		$198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	
3 Less: *Accumulated Depreciation*		(5,847)	(6,283)	(6,719)	(7,155)	(7,591)	(8,027)	(8,463)	(8,899)	(9,335)	(9,771)	(10,207)	(10,643)	(11,079)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$193,141	192,705	192,269	191,833	191,397	190,961	190,525	190,089	189,653	189,217	188,781	188,345	187,909	
6 Average Net Investment			192,923	192,487	192,051	191,615	191,179	190,743	190,307	189,871	189,435	188,999	188,563	188,127	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		1,794	1,790	1,786	1,782	1,778	1,774	1,770	1,766	1,762	1,758	1,754	1,750	$21,264
b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		328	327	326	326	325	324	324	323	322	321	321	320	3,887
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. *Depreciation*	2.63%		436	436	436	436	436	436	436	436	436	436	436	436	5,232
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	0.009130		151	151	151	151	151	151	151	151	151	151	151	151	1,812
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			2,709	2,704	2,699	2,695	2,690	2,685	2,681	2,676	2,671	2,666	2,662	2,657	32,195
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			2,709	2,704	2,699	2,695	2,690	2,685	2,681	2,676	2,671	2,666	2,662	2,657	32,195

For Project: CAIR CTs - DeBARY (Project 7.2d)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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*		$87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	
3 Less: Accumulated Depreciation		(3,399)	(3,647)	(3,895)	(4,143)	(4,391)	(4,639)	(4,887)	(5,135)	(5,383)	(5,631)	(5,879)	(6,127)	(6,375)	
4 CWIP - Non-Interest Bearing		0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5 Net Investment (Lines 2 + 3 + 4)		$84,269	84,020	83,772	83,524	83,276	83,028	82,780	82,532	82,284	82,036	81,788	81,540	81,292	
6 Average Net Investment			84,144	83,896	83,648	83,400	83,152	82,904	82,656	82,408	82,160	81,912	81,664	81,416	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		783	780	778	776	773	771	769	766	764	762	759	757	$9,238
b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		143	143	142	142	141	141	141	140	140	139	139	138	1,689
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	3.39%		248	248	248	248	248	248	248	248	248	248	248	248	2,976
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	0.009270		68	68	68	68	68	68	68	68	68	68	68	68	816
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			1,242	1,239	1,236	1,234	1,230	1,228	1,226	1,222	1,220	1,217	1,214	1,211	14,719
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			1,242	1,239	1,236	1,234	1,230	1,228	1,226	1,222	1,220	1,217	1,214	1,211	14,719

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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2009 through December 2009
Pipline Intergrity Management (Project 3 Recap)

For Project: CAIR CTs - HIGGINS (Project 7.2e)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1	Investments															$0
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	
3	Less: Accumulated Depreciation		(3,241)	(3,529)	(3,817)	(4,105)	(4,393)	(4,681)	(4,969)	(5,257)	(5,545)	(5,833)	(6,121)	(6,409)	(6,697)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$342,249	341,961	341,673	341,385	341,097	340,809	340,521	340,233	339,945	339,657	339,369	339,081	338,793	
6	Average Net Investment			342,105	341,817	341,529	341,241	340,953	340,665	340,377	340,089	339,801	339,513	339,225	338,937	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		3,182	3,179	3,176	3,174	3,171	3,168	3,166	3,163	3,160	3,157	3,155	3,152	$38,003
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		582	581	581	580	580	579	579	578	578	577	577	576	6,948
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.00%		288	288	288	288	288	288	288	288	288	288	288	288	3,456
	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	0.009130		263	263	263	263	263	263	263	263	263	263	263	263	3,156
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			4,315	4,311	4,308	4,305	4,302	4,298	4,296	4,292	4,289	4,285	4,283	4,279	51,563
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			4,315	4,311	4,308	4,305	4,302	4,298	4,296	4,292	4,289	4,285	4,283	4,279	51,563

For Project: CAIR CTs - INTERCESSION CITY (Project 7.2f)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1	Investments															$0
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	
3	Less: Accumulated Depreciation		(10,267)	(11,033)	(11,799)	(12,565)	(13,331)	(14,097)	(14,863)	(15,629)	(16,395)	(17,161)	(17,927)	(18,693)	(19,459)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$339,317	338,551	337,785	337,019	336,253	335,487	334,721	333,955	333,189	332,423	331,657	330,891	330,125	
6	Average Net Investment			338,934	338,168	337,402	336,636	335,870	335,104	334,338	333,572	332,806	332,040	331,274	330,508	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		3,152	3,145	3,138	3,131	3,124	3,116	3,109	3,102	3,095	3,088	3,081	3,074	$37,355
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		576	575	574	572	571	570	568	567	566	564	563	562	6,828
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.63%		766	766	766	766	766	766	766	766	766	766	766	766	9,192
	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	0.007740		225	225	225	225	225	225	225	225	225	225	225	225	2,700
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			4,719	4,711	4,703	4,694	4,686	4,677	4,668	4,660	4,652	4,643	4,635	4,627	56,075
	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			4,719	4,711	4,703	4,694	4,686	4,677	4,668	4,660	4,652	4,643	4,635	4,627	56,075

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For Project: CAIR CTs - TURNER (Project 7.2g)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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		$134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	
3	Less: Accumulated Depreciation		(4,096)	(4,401)	(4,707)	(5,013)	(5,319)	(5,625)	(5,931)	(6,237)	(6,543)	(6,849)	(7,155)	(7,461)	(7,767)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$129,917	129,611	129,305	128,999	128,693	128,387	128,081	127,775	127,469	127,163	126,857	126,551	126,245	
6	Average Net Investment			129,764	129,458	129,152	128,846	128,540	128,234	127,928	127,622	127,316	127,010	126,704	126,398	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		1,207	1,204	1,201	1,198	1,195	1,193	1,190	1,187	1,184	1,181	1,178	1,176	$14,294
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		221	220	220	219	219	218	217	217	216	216	215	215	2,613
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.74%		306	306	306	306	306	306	306	306	306	306	306	306	3,672
	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	0.009270		104	104	104	104	104	104	104	104	104	104	104	104	1,248
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,838	1,834	1,831	1,827	1,824	1,821	1,817	1,814	1,810	1,807	1,803	1,801	21,827
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,838	1,834	1,831	1,827	1,824	1,821	1,817	1,814	1,810	1,807	1,803	1,801	21,827

For Project: CAIR CTs - SUWANNEE (Project 7.2h)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	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		$381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	
3	Less: Accumulated Depreciation		(7,734)	(8,408)	(9,082)	(9,756)	(10,430)	(11,104)	(11,778)	(12,452)	(13,126)	(13,800)	(14,474)	(15,148)	(15,822)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$373,826	373,152	372,478	371,804	371,130	370,456	369,782	369,108	368,434	367,760	367,086	366,412	365,738	
6	Average Net Investment			373,489	372,815	372,141	371,467	370,793	370,119	369,445	368,771	368,097	367,423	366,749	366,075	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	11.16%		3,473	3,467	3,461	3,455	3,448	3,442	3,436	3,430	3,423	3,417	3,411	3,404	$41,267
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.04%		635	634	633	631	630	629	628	627	626	625	623	622	7,543
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.12%		674	674	674	674	674	674	674	674	674	674	674	674	8,088
	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	0.007850		250	250	250	250	250	250	250	250	250	250	250	250	3,000
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			5,032	5,025	5,018	5,010	5,002	4,995	4,988	4,981	4,973	4,966	4,958	4,950	59,898
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			5,032	5,025	5,018	5,010	5,002	4,995	4,988	4,981	4,973	4,966	4,958	4,950	59,898

For Project: CAIR/CAMR Crystal River AFUDC - Access Road and Vehicle Barrier System (Project 7.4a)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1 Investments															
a. Expenditures/Additions			$0	$77,700	($799,917)	$49,876	$48	$0	$0	$0	$0	$0	$0	$0	($672,293)
b. Clearings to Plant			0	77,700	(799,917)	49,876	48	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		$16,162,675	16,162,675	16,240,375	15,440,458	15,490,334	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	
3 Less: Accumulated Depreciation		(334,407)	(380,067)	(425,946)	(469,565)	(513,325)	(557,085)	(600,845)	(644,605)	(688,365)	(732,125)	(775,885)	(819,645)	(863,405)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$15,828,268	15,782,608	15,814,429	14,970,894	14,977,009	14,933,297	14,889,537	14,845,777	14,802,017	14,758,257	14,714,497	14,670,737	14,626,977	
6 Average Net Investment			15,805,438	15,798,519	15,392,662	14,973,952	14,955,153	14,911,417	14,867,657	14,823,897	14,780,137	14,736,377	14,692,617	14,648,857	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		146,991	146,926	143,152	139,258	139,083	138,676	138,269	137,862	137,455	137,048	136,641	136,234	$1,677,595
b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		26,869	26,857	26,168	25,456	25,424	25,349	25,275	25,201	25,126	25,052	24,977	24,903	306,657
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	3.39%		45,660	45,879	43,619	43,760	43,760	43,760	43,760	43,760	43,760	43,760	43,760	43,760	528,998
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	0.010480		14,115	14,183	13,485	13,528	13,528	13,528	13,528	13,528	13,528	13,528	13,528	13,528	163,535
e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			233,635	233,845	226,424	222,002	221,795	221,313	220,832	220,351	219,869	219,388	218,906	218,425	2,676,785
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			233,635	233,845	226,424	222,002	221,795	221,313	220,832	220,351	219,869	219,388	218,906	218,425	2,676,785

For Project: CAIR/CAMR Crystal River AFUDC - UNIT 4 LNB/AH (Project 7.4b)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1 Investments															
a. Expenditures/Additions			$1,596,194	$4,331	$127,144	$14,146	$3,030,352	$50,405	$0	$0	$0	$0	$0	$0	$4,822,572
b. Clearings to Plant			1,596,194	4,331	127,144	14,146	3,030,352	50,405	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		$5,599,409	7,195,602	7,199,934	7,327,077	7,341,223	10,371,575	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	
3 Less: Accumulated Depreciation		(6,603)	(23,573)	(40,553)	(57,833)	(75,146)	(99,606)	(124,185)	(148,764)	(173,343)	(197,922)	(222,501)	(247,080)	(271,659)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5 Net Investment (Lines 2 + 3 + 4)		$5,592,806	7,172,030	7,159,381	7,269,245	7,266,078	10,271,970	10,297,796	10,273,217	10,248,638	10,224,059	10,199,480	10,174,901	10,150,322	
6 Average Net Investment			6,382,418	7,165,706	7,214,313	7,267,661	8,769,024	10,284,883	10,285,506	10,260,927	10,236,348	10,211,769	10,187,190	10,162,611	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	11.16%		59,356	66,641	67,093	67,589	81,552	95,649	95,655	95,427	95,198	94,969	94,741	94,512	$1,008,382
b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		10,850	12,182	12,264	12,355	14,907	17,484	17,485	17,444	17,402	17,360	17,318	17,276	184,327
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	2.83%		16,970	16,980	17,280	17,313	24,460	24,579	24,579	24,579	24,579	24,579	24,579	24,579	265,056
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	0.010480		6,284	6,288	6,399	6,411	9,058	9,102	9,102	9,102	9,102	9,102	9,102	9,102	98,154
e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			93,460	102,091	103,036	103,668	129,977	146,814	146,821	146,552	146,281	146,010	145,740	145,469	1,555,919
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			93,460	102,091	103,036	103,668	129,977	146,814	146,821	146,552	146,281	146,010	145,740	145,469	1,555,919

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Deatil Support - January 2009 through December 2009
Pipline Intergrity Management (Project 3 Recap)

For Project: CAIR/CAMR Crystal River AFUDC - Selective Catalytic Reduction CR5 (Project 7.4c)
(In Dollars)

Line Description	Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1 Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$91,273,742	648,614	465,714	44,167	20,833	20,833	20,833	$92,494,737
b. Clearings to Plant		0	0	0	0	0	91,273,742	648,614	465,714	44,167	20,833	20,833	20,833	
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	91,273,742	91,922,356	92,388,070	92,432,237	92,453,070	92,473,903	92,494,737	
3 Less: Accumulated Depreciation	0	0	0	0	0	0	(107,627)	(324,411)	(542,293)	(760,279)	(978,314)	(1,196,398)	(1,414,531)	
4 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	91,166,115	91,597,945	91,845,777	91,671,958	91,474,756	91,277,505	91,080,206	
6 Average Net Investment		0	0	0	0	0	45,583,058	91,382,030	91,721,861	91,758,867	91,573,357	91,376,131	91,178,856	
7 Return on Average Net Investment														
a. Equity Component Grossed Up For Taxes 11.16%		0	0	0	0	0	423,922	849,853	853,013	853,357	851,632	849,798	847,963	$5,529,538
b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		0	0	0	0	0	77,491	155,349	155,927	155,990	155,675	155,339	155,004	1,010,775
c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses														
a. Depreciation 2.83%		0	0	0	0	0	107,627	216,784	217,882	217,986	218,035	218,084	218,133	1,414,531
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 0.010480		0	0	0	0	0	79,712	80,279	80,686	80,724	80,742	80,761	80,779	563,683
e. Property Insurance		0	0	0	0	0	0	0	0	0	0	0	0	0
f. 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	688,752	1,302,265	1,307,508	1,308,057	1,306,084	1,303,982	1,301,879	8,518,527
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	688,752	1,302,265	1,307,508	1,308,057	1,306,084	1,303,982	1,301,879	8,518,527

For Project: CAIR/CAMR Crystal River AFUDC - FGD Common (Project 7.4d)
(in Dollars)

Line Description	Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1 Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$634,421,721	$634,421,721
b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	634,421,721	
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	634,421,721	
3 Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	(748,089)	
4 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	633,673,632	
6 Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	316,836,816	
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	0	2,946,582	$2,946,582
b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		0	0	0	0	0	0	0	0	0	0	0	538,623	538,623
c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses														
a. Depreciation 2.83%		0	0	0	0	0	0	0	0	0	0	0	748,089	748,089
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 0.010480		0	0	0	0	0	0	0	0	0	0	0	554,062	554,062
e. Property Insurance		0	0	0	0	0	0	0	0	0	0	0	0	0
f. 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	4,787,356	4,787,356
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	4,787,356	4,787,356

For Project: CAIR/CAMR Crystal River AFUDC - SCR Common Items (Project 7.4e)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	69,831,473	$0	$0	$0	$0	$0	$69,831,473
	b. Clearings to Plant		0	0	0	0	0	0	69,831,473	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	69,831,473	69,831,473	69,831,473	69,831,473	69,831,473	69,831,473	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	(82,343)	(247,029)	(411,715)	(576,401)	(741,087)	(905,773)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$0	0	0	0	0	0	0	69,749,130	69,584,444	69,419,758	69,255,072	69,090,386	68,925,700	
6	Average Net Investment		0	0	0	0	0	0	34,874,565	69,666,787	69,502,101	69,337,415	69,172,729	69,008,043	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 11.16%		0	0	0	0	0	0	324,333	647,901	646,370	644,838	643,306	641,775	$3,548,523
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		0	0	0	0	0	0	59,287	118,434	118,154	117,874	117,594	117,314	648,657
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation 2.83%		0	0	0	0	0	0	82,343	164,686	164,686	164,686	164,686	164,686	905,773
	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 0.010480		0	0	0	0	0	0	60,986	60,986	60,986	60,986	60,986	60,986	365,916
	e. Property Insurance		0	0	0	0	0	0	0	0	0	0	0	0	0
	f. 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	526,949	992,007	990,196	988,384	986,572	984,761	5,468,869
	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		0	0	0	0	0	0	526,949	992,007	990,196	988,384	986,572	984,761	5,468,869

For Project: CAIR/CAMR Crystal River AFUDC - Flue Gas Desulfurization CR5 (Project 7.4f)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	135,013,655	$135,013,655
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	135,013,655	
	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	$0	0	0	0	0	0	0	0	0	0	0	0	135,013,655	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	(159,204)	
4	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	134,854,452	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	67,427,226	
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	0	627,073	$627,073
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.04%		0	0	0	0	0	0	0	0	0	0	0	114,626	114,626
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation 2.83%		0	0	0	0	0	0	0	0	0	0	0	159,204	159,204
	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 0.010480		0	0	0	0	0	0	0	0	0	0	0	117,912	117,912
	e. Property Insurance		0	0	0	0	0	0	0	0	0	0	0	0	0
	f. 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	1,018,815	1,018,815
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	1,018,815	1,018,815

For Project: CAIR/CAMR Crystal River AFUDC - CR5 Sootblower & Intelligent Soot Blowing Controls(Project 7.4g)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-09	Actual Feb-09	Actual Mar-09	Actual Apr-09	Actual May-09	Actual Jun-09	Estimated Jul-09	Estimated Aug-09	Estimated Sep-09	Estimated Oct-09	Estimated Nov-09	Estimated Dec-09	End of Period Total
1 Investments															
a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$ 929,220	$929,220
b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	929,220	
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	929,220	
3 Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	(1,096)	
4 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	928,125	
6 Average Net Investment			0	0	0	0	0	0	0	0	0	0	0	464,062	
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	0	4,316	$4,316
b. Debt Component (Line 6 x 2.04% x 1/12)	2.04%		0	0	0	0	0	0	0	0	0	0	0	789	789
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	2.83%		0	0	0	0	0	0	0	0	0	0	0	1,096	1,096
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	0.010480		0	0	0	0	0	0	0	0	0	0	0	812	812
e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
f. 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	7,013	7,013
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			0	0	0	0	0	0	0	0	0	0	0	7,013	7,013

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. ___ (TGF-2)

Witness: T.G. Foster
Exibit__(TGF-4)

PROGRESS ENERGY FLORIDA, INC.
ENVIRONMENTAL COST RECOVERY
CAPITAL PROGRAM DETAIL

JANUARY 2010 - DECEMBER 2010
Calculation of the Projected Period Amount
January through December 2010
DOCKET NO. 090007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 27
COMPANY Progress Energy Florida, Inc.
WITNESS Thomas G. Foster (TGF-4)
DATE 11/02/09

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No.__(TGF-4)
Page 1 of 19

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 3.1 Recap
JANUARY 2010 - DECEMBER 2010

For Project: PIPELINE INTEGRITY MANAGEMENT - Alderman Road Fence (Project 3.1a)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	
3	Less: Accumulated Depreciation		($5,497)	(5,586)	(5,675)	(5,764)	(5,853)	(5,942)	(6,031)	(6,120)	(6,209)	(6,298)	(6,387)	(6,476)	(6,565)	
4	CWIP - Non-Interest Bearing		$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$28,456	28,367	28,278	28,189	28,100	28,011	27,922	27,833	27,744	27,655	27,566	27,477	27,388	
6	Average Net Investment			28,411	28,322	28,233	28,144	28,055	27,966	27,877	27,788	27,699	27,610	27,521	27,432	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.38%		245	244	243	243	242	241	240	240	239	238	237	237	$2,889
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.86%		68	67	67	67	67	66	66	66	66	66	65	65	796
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.13%		89	89	89	89	89	89	89	89	89	89	89	89	1,068
	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	0.008907		25	25	25	25	25	25	25	25	25	25	25	25	300
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			427	425	424	424	423	421	420	420	419	418	416	416	5,053
	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			427	425	424	424	423	421	420	420	419	418	416	416	5,053

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Leak Detection (Project 3.1b)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$2,640,836	2,640,836	2,640,836	2,640,836	2,640,836	2,640,836	2,640,836	2,640,836	2,640,836	2,640,836	2,640,836	2,640,836	2,640,836	
3	Less: Accumulated Depreciation		($521,875)	(533,030)	(544,385)	(555,740)	(567,095)	(578,450)	(589,805)	(601,160)	(612,515)	(623,870)	(635,225)	(646,580)	(657,935)	
4	CWIP - Non-Interest Bearing		$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$2,118,961	2,107,606	2,096,251	2,084,896	2,073,541	2,062,186	2,050,831	2,039,476	2,028,121	2,016,766	2,005,411	1,994,056	1,982,701	
6	Average Net Investment			2,113,284	2,101,929	2,090,574	2,079,219	2,067,864	2,056,509	2,045,154	2,033,799	2,022,444	2,011,089	1,999,734	1,988,379	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.38%		18,220	18,122	18,024	17,926	17,828	17,731	17,633	17,535	17,437	17,339	17,241	17,143	$212,179
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.86%		5,024	4,997	4,970	4,943	4,916	4,889	4,862	4,835	4,808	4,781	4,754	4,727	58,506
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	5.16%		11,355	11,355	11,355	11,355	11,355	11,355	11,355	11,355	11,355	11,355	11,355	11,355	136,260
	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	0.008907		1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	23,520
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			36,559	36,434	36,309	36,184	36,059	35,935	35,810	35,685	35,560	35,435	35,310	35,185	430,465
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			36,559	36,434	36,309	36,184	36,059	35,935	35,810	35,685	35,560	35,435	35,310	35,185	430,465

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 3.1 Recap
JANUARY 2010 - DECEMBER 2010

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Controls Upgrade (Project 3.1c)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$905,147	905,147	905,147	905,147	905,147	905,147	905,147	905,147	905,147	905,147	905,147	905,147	905,147	
3	Less: Accumulated Depreciation		($38,236)	(42,128)	(46,020)	(49,912)	(53,804)	(57,696)	(61,588)	(65,480)	(69,372)	(73,264)	(77,156)	(81,048)	(84,940)	
4	CWIP - Non-Interest Bearing		($0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$866,911	863,019	859,127	855,235	851,343	847,451	843,559	839,667	835,775	831,883	827,991	824,099	820,207	
6	Average Net Investment			864,965	861,073	857,181	853,289	849,397	845,505	841,613	837,721	833,829	829,937	826,045	822,153	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		7,457	7,424	7,390	7,357	7,323	7,290	7,256	7,223	7,189	7,155	7,122	7,088	$87,274
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		2,056	2,047	2,038	2,029	2,019	2,010	2,001	1,992	1,982	1,973	1,964	1,955	24,066
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	5.16%		3,892	3,892	3,892	3,892	3,892	3,892	3,892	3,892	3,892	3,892	3,892	3,892	46,704
	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	0.008907		672	672	672	672	672	672	672	672	672	672	672	672	8,064
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			14,077	14,035	13,992	13,950	13,906	13,864	13,821	13,779	13,735	13,692	13,650	13,607	166,108
	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			14,077	14,035	13,992	13,950	13,906	13,864	13,821	13,779	13,735	13,692	13,650	13,607	166,108

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
JANUARY 2010 - DECEMBER 2010

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - TURNER CTs (Project 4.1a)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$1,954,499	1,954,499	1,954,499	1,954,499	1,954,499	1,954,499	1,954,499	1,954,499	1,954,499	1,954,499	1,954,499	1,954,499	1,954,499	
3	Less: Accumulated Depreciation		(35,776)	(46,879)	(57,982)	(69,085)	(80,188)	(91,291)	(102,394)	(113,497)	(124,600)	(135,703)	(146,806)	(157,909)	(169,012)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$1,918,723	1,907,620	1,896,517	1,885,414	1,874,311	1,863,208	1,852,105	1,841,002	1,829,899	1,818,796	1,807,693	1,796,590	1,785,487	
6	Average Net Investment			1,913,171	1,902,068	1,890,965	1,879,862	1,868,759	1,857,656	1,846,553	1,835,450	1,824,347	1,813,244	1,802,141	1,791,038	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		16,495	16,399	16,303	16,208	16,112	16,016	15,920	15,825	15,729	15,633	15,537	15,442	$191,619
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.85%		4,549	4,522	4,496	4,469	4,443	4,417	4,390	4,364	4,337	4,311	4,285	4,258	52,841
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	6.82%		11,103	11,103	11,103	11,103	11,103	11,103	11,103	11,103	11,103	11,103	11,103	11,103	133,236
	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	0.009278		1,510	1,510	1,510	1,510	1,510	1,510	1,510	1,510	1,510	1,510	1,510	1,510	18,120
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			33,657	33,534	33,412	33,290	33,168	33,046	32,923	32,802	32,679	32,557	32,435	32,313	385,816
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			33,657	33,534	33,412	33,290	33,168	33,046	32,923	32,802	32,679	32,557	32,435	32,313	385,816

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BARTOW CTs (Project 4.1b)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$155,000	$260,000	$223,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$638,000
	b. Clearings to Plant			0	0	1,513,040	0	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	1,666,738	1,666,738	1,666,738	1,666,738	1,666,738	1,666,738	1,666,738	1,666,738	1,666,738	1,666,738	
3	Less: Accumulated Depreciation		(35,684)	(36,194)	(36,704)	(39,488)	(44,996)	(50,524)	(56,052)	(61,580)	(67,108)	(72,636)	(78,164)	(83,692)	(89,220)	
4	CWIP - Non-Interest Bearing		875,040	1,030,040	1,290,040	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$993,055	1,147,545	1,407,035	1,627,271	1,621,743	1,616,215	1,610,687	1,605,159	1,599,631	1,594,103	1,588,575	1,583,047	1,577,519	
6	Average Net Investment			1,070,300	1,277,290	1,517,153	1,624,507	1,618,979	1,613,451	1,607,923	1,602,395	1,596,867	1,591,339	1,585,811	1,580,283	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		9,228	11,012	13,080	14,006	13,958	13,911	13,863	13,815	13,768	13,720	13,672	13,625	$157,658
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.85%		2,545	3,037	3,607	3,862	3,849	3,836	3,823	3,810	3,797	3,783	3,770	3,757	43,476
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.98%		510	510	2,784	5,528	5,528	5,528	5,528	5,528	5,528	5,528	5,528	5,528	53,536
	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	0.009130		117	117	1,268	1,268	1,268	1,268	1,268	1,268	1,268	1,268	1,268	1,268	12,914
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			12,400	14,676	20,719	24,664	24,603	24,543	24,482	24,421	24,361	24,299	24,238	24,178	267,584
	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			12,400	14,676	20,719	24,664	24,603	24,543	24,482	24,421	24,361	24,299	24,238	24,178	267,584

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
JANUARY 2010 - DECEMBER 2010

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 1 & 2 (Project 4.2)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		(8,547)	(8,706)	(8,865)	(9,024)	(9,183)	(9,342)	(9,501)	(9,660)	(9,819)	(9,978)	(10,137)	(10,296)	(10,455)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$24,545	24,386	24,227	24,068	23,909	23,750	23,591	23,432	23,273	23,114	22,955	22,796	22,637	
6	Average Net Investment			24,465	24,306	24,147	23,988	23,829	23,670	23,511	23,352	23,193	23,034	22,875	22,716	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		211	210	208	207	205	204	203	201	200	199	197	196	$2,441
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.85%		58	58	57	57	57	56	56	56	55	55	54	54	673
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	5.77%		159	159	159	159	159	159	159	159	159	159	159	159	1,908
	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	0.010489		29	29	29	29	29	29	29	29	29	29	29	29	348
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			457	456	453	452	450	448	447	445	443	442	439	438	5,370
	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			457	456	453	452	450	448	447	445	443	442	439	438	5,370

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - INTERCESSION CITY CTs (Project 4.1c)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	
3	Less: Accumulated Depreciation		(176,123)	(190,247)	(204,371)	(218,495)	(232,619)	(246,743)	(260,867)	(274,991)	(289,115)	(303,239)	(317,363)	(331,487)	(345,611)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$1,485,541	1,471,417	1,457,293	1,443,169	1,429,045	1,414,921	1,400,797	1,386,673	1,372,549	1,358,425	1,344,301	1,330,177	1,316,053	
6	Average Net Investment			1,478,479	1,464,355	1,450,231	1,436,107	1,421,983	1,407,859	1,393,735	1,379,611	1,365,487	1,351,363	1,337,239	1,323,115	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		12,747	12,625	12,503	12,382	12,260	12,138	12,016	11,895	11,773	11,651	11,529	11,407	$144,926
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.85%		3,515	3,482	3,448	3,414	3,381	3,347	3,314	3,280	3,246	3,213	3,179	3,146	39,965
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	10.20%		14,124	14,124	14,124	14,124	14,124	14,124	14,124	14,124	14,124	14,124	14,124	14,124	169,488
	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	0.007740		1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	1,072	12,864
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			31,458	31,303	31,147	30,992	30,837	30,681	30,526	30,371	30,215	30,060	29,904	29,749	367,243
	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			31,458	31,303	31,147	30,992	30,837	30,681	30,526	30,371	30,215	30,060	29,904	29,749	367,243

cpd

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
JANUARY 2010 - DECEMBER 2010

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - AVON PARK CTs (Project 4.1d)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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*		(21,161)	(22,096)	(23,031)	(23,966)	(24,901)	(25,836)	(26,771)	(27,706)	(28,641)	(29,576)	(30,511)	(31,446)	(32,381)	
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)		$157,777	156,842	155,907	154,972	154,037	153,102	152,167	151,232	150,297	149,362	148,427	147,492	146,557	
6	Average Net Investment			157,309	156,374	155,439	154,504	153,569	152,634	151,699	150,764	149,829	148,894	147,959	147,024	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		1,356	1,348	1,340	1,332	1,324	1,316	1,308	1,300	1,292	1,284	1,276	1,268	$15,744
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.85%		374	372	370	367	365	363	361	358	356	354	352	350	4,342
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	6.27%		935	935	935	935	935	935	935	935	935	935	935	935	11,220
	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	0.008780		131	131	131	131	131	131	131	131	131	131	131	131	1,572
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,796	2,786	2,776	2,765	2,755	2,745	2,735	2,724	2,714	2,704	2,694	2,684	32,878
	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			2,796	2,786	2,776	2,765	2,755	2,745	2,735	2,724	2,714	2,704	2,694	2,684	32,878

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BAYBORO CTs (Project 4.1e)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	
3	Less: Accumulated Depreciation		(45,596)	(47,903)	(50,210)	(52,517)	(54,824)	(57,131)	(59,438)	(61,745)	(64,052)	(66,359)	(68,666)	(70,973)	(73,280)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$684,699	682,393	680,086	677,779	675,472	673,165	670,858	668,551	666,244	663,937	661,630	659,323	657,016	
6	Average Net Investment			683,546	681,239	678,932	676,625	674,318	672,011	669,704	667,397	665,090	662,783	660,476	658,169	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		5,893	5,873	5,854	5,834	5,814	5,794	5,774	5,754	5,734	5,714	5,694	5,675	$69,407
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.85%		1,626	1,620	1,614	1,609	1,603	1,598	1,592	1,587	1,581	1,576	1,570	1,565	19,140
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.79%		2,307	2,307	2,307	2,307	2,307	2,307	2,307	2,307	2,307	2,307	2,307	2,307	27,684
	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	0.009120		556	556	556	556	556	556	556	556	556	556	556	556	6,672
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			10,381	10,356	10,331	10,306	10,280	10,255	10,229	10,204	10,178	10,153	10,127	10,103	122,903
	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			10,381	10,356	10,331	10,306	10,280	10,255	10,229	10,204	10,178	10,153	10,127	10,103	122,903

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. ___ (TGF-4)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
JANUARY 2010 - DECEMBER 2010

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - SUWANNEE CTs (Project 4.1f)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	
3	Less: Accumulated Depreciation		(84,360)	(87,999)	(91,638)	(95,277)	(98,916)	(102,555)	(106,194)	(109,833)	(113,472)	(117,111)	(120,750)	(124,389)	(128,028)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$952,839	949,200	945,561	941,922	938,283	934,644	931,005	927,366	923,727	920,088	916,449	912,810	909,171	
6	Average Net Investment			951,020	947,381	943,742	940,103	936,464	932,825	929,186	925,547	921,908	918,269	914,630	910,991	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		8,199	8,168	8,137	8,105	8,074	8,043	8,011	7,980	7,948	7,917	7,886	7,854	$96,322
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.85%		2,251	2,252	2,244	2,235	2,226	2,218	2,209	2,200	2,192	2,183	2,175	2,166	26,551
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	4.21%		3,639	3,639	3,639	3,639	3,639	3,639	3,639	3,639	3,639	3,639	3,639	3,639	43,668
	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	0.007850		679	679	679	679	679	679	679	679	679	679	679	679	8,148
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			14,778	14,738	14,699	14,658	14,618	14,579	14,538	14,498	14,458	14,418	14,379	14,338	174,699
	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			14,778	14,738	14,699	14,658	14,618	14,579	14,538	14,498	14,458	14,418	14,379	14,338	174,699

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - DeBARY CTs (Project 4.1g)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	2,373,773	
3	Less: Accumulated Depreciation		(37,782)	(46,703)	(55,624)	(64,545)	(73,466)	(82,387)	(91,308)	(100,229)	(109,150)	(118,071)	(126,992)	(135,913)	(144,834)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$2,335,991	2,327,070	2,318,149	2,309,228	2,300,307	2,291,386	2,282,465	2,273,544	2,264,623	2,255,702	2,246,781	2,237,860	2,228,939	
6	Average Net Investment			2,331,531	2,322,610	2,313,689	2,304,768	2,295,847	2,286,926	2,278,005	2,269,084	2,260,163	2,251,242	2,242,321	2,233,400	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		20,102	20,025	19,948	19,871	19,794	19,717	19,640	19,563	19,486	19,409	19,333	19,256	$236,144
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.85%		5,543	5,522	5,501	5,480	5,458	5,437	5,416	5,395	5,374	5,352	5,331	5,310	65,119
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	4.51%		8,921	8,921	8,921	8,921	8,921	8,921	8,921	8,921	8,921	8,921	8,921	8,921	107,052
	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	0.009270		1,834	1,834	1,834	1,834	1,834	1,834	1,834	1,834	1,834	1,834	1,834	1,834	22,008
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			36,400	36,302	36,204	36,106	36,007	35,909	35,811	35,713	35,615	35,516	35,419	35,321	430,323
	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			36,400	36,302	36,204	36,106	36,007	35,909	35,811	35,713	35,615	35,516	35,419	35,321	430,323

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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
JANUARY 2010 - DECEMBER 2010

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - University of Florida (Project 4.1h)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		(37,326)	(37,642)	(37,958)	(38,274)	(38,590)	(38,906)	(39,222)	(39,538)	(39,854)	(40,170)	(40,486)	(40,802)	(41,118)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$104,108	103,792	103,476	103,160	102,844	102,528	102,212	101,896	101,580	101,264	100,948	100,632	100,316	
6	Average Net Investment			103,950	103,634	103,318	103,002	102,686	102,370	102,054	101,738	101,422	101,106	100,790	100,474	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		896	893	891	888	885	883	880	877	874	872	869	866	$10,574
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.86%		247	246	246	245	244	243	243	242	241	240	240	239	2,916
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.68%		316	316	316	316	316	316	316	316	316	316	316	316	3,792
	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	0.013790		163	163	163	163	163	163	163	163	163	163	163	163	1,956
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,622	1,618	1,616	1,612	1,608	1,605	1,602	1,598	1,594	1,591	1,588	1,584	19,238
	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			1,622	1,618	1,616	1,612	1,608	1,605	1,602	1,598	1,594	1,591	1,588	1,584	19,238

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Anclote (Project 4.3)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	
3	Less: Accumulated Depreciation		(22,218)	(23,253)	(24,288)	(25,323)	(26,358)	(27,393)	(28,428)	(29,463)	(30,498)	(31,533)	(32,568)	(33,603)	(34,638)	
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)		$268,080	267,045	266,010	264,975	263,940	262,905	261,870	260,835	259,800	258,765	257,730	256,695	255,660	
6	Average Net Investment			267,562	266,527	265,492	264,457	263,422	262,387	261,352	260,317	259,282	258,247	257,212	256,177	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		2,307	2,298	2,289	2,280	2,271	2,262	2,253	2,244	2,235	2,227	2,218	2,209	$27,093
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.86%		636	634	631	629	626	624	621	619	616	614	612	608	7,471
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	4.28%		1,035	1,035	1,035	1,035	1,035	1,035	1,035	1,035	1,035	1,035	1,035	1,035	12,420
	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	0.007100		172	172	172	172	172	172	172	172	172	172	172	172	2,064
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			4,150	4,139	4,127	4,116	4,104	4,093	4,081	4,070	4,058	4,048	4,037	4,025	49,048
	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			4,150	4,139	4,127	4,116	4,104	4,093	4,081	4,070	4,058	4,048	4,037	4,025	49,048

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. __ (TGF-4)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
JANUARY 2010 - DECEMBER 2010

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Crystal River 4 & 5 (Project 4.2a)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	2,035,698	
3	Less: Accumulated Depreciation		(59,422)	(63,833)	(68,244)	(72,655)	(77,066)	(81,477)	(85,888)	(90,299)	(94,710)	(99,121)	(103,532)	(107,943)	(112,354)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$1,976,276	1,971,865	1,967,454	1,963,043	1,958,632	1,954,221	1,949,810	1,945,399	1,940,988	1,936,577	1,932,166	1,927,755	1,923,344	
6	Average Net Investment			1,974,071	1,969,660	1,965,249	1,960,838	1,956,427	1,952,016	1,947,605	1,943,194	1,938,783	1,934,372	1,929,961	1,925,550	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		17,020	16,982	16,944	16,906	16,868	16,830	16,792	16,754	16,716	16,678	16,639	16,601	$201,730
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.85%		4,693	4,683	4,672	4,662	4,651	4,641	4,630	4,620	4,609	4,599	4,588	4,578	55,628
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.60%		4,411	4,411	4,411	4,411	4,411	4,411	4,411	4,411	4,411	4,411	4,411	4,411	52,932
	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	0.010480		1,778	1,778	1,778	1,778	1,778	1,778	1,778	1,778	1,778	1,778	1,778	1,778	21,336
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			27,902	27,854	27,805	27,757	27,708	27,660	27,611	27,563	27,514	27,466	27,416	27,368	331,624
	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			27,902	27,854	27,805	27,757	27,708	27,660	27,611	27,563	27,514	27,466	27,416	27,368	331,624

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Higgins (Project 4.1f)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$343,893	343,893	343,893	343,893	343,893	343,893	343,893	343,893	343,893	343,893	343,893	343,893	343,893	
3	Less: Accumulated Depreciation		(10,374)	(10,956)	(11,538)	(12,120)	(12,702)	(13,284)	(13,866)	(14,448)	(15,030)	(15,612)	(16,194)	(16,776)	(17,358)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$333,519	332,937	332,355	331,773	331,191	330,609	330,027	329,445	328,863	328,281	327,699	327,117	326,535	
6	Average Net Investment			333,228	332,646	332,064	331,482	330,900	330,318	329,736	329,154	328,572	327,990	327,408	326,826	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		2,873	2,868	2,863	2,858	2,853	2,848	2,843	2,838	2,833	2,828	2,823	2,818	$34,146
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.85%		792	791	789	788	787	785	784	783	781	780	778	777	9,415
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.03%		582	582	582	582	582	582	582	582	582	582	582	582	6,984
	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	0.009130		262	262	262	262	262	262	262	262	262	262	262	262	3,144
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			4,509	4,503	4,496	4,490	4,484	4,477	4,471	4,465	4,458	4,452	4,446	4,439	53,669
	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			4,509	4,503	4,496	4,490	4,484	4,477	4,471	4,465	4,458	4,452	4,446	4,439	53,669

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.2 Recap
JANUARY 2010 - DECEMBER 2010

For Project: CAIR CTs - AVON PARK (Project 7.2a)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	
3	Less: Accumulated Depreciation		(4,553)	(5,150)	(5,747)	(6,344)	(6,941)	(7,538)	(8,135)	(8,732)	(9,329)	(9,926)	(10,523)	(11,120)	(11,717)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$157,201	156,604	156,007	155,410	154,813	154,216	153,619	153,022	152,425	151,828	151,231	150,634	150,037	
6	Average Net Investment			156,903	156,306	155,709	155,112	154,515	153,918	153,321	152,724	152,127	151,530	150,933	150,336	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.38%		1,353	1,348	1,342	1,337	1,332	1,327	1,322	1,317	1,312	1,306	1,301	1,296	$15,893
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.85%		373	372	370	369	367	366	365	363	362	360	359	357	4,383
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	4.43%		597	597	597	597	597	597	597	597	597	597	597	597	7,164
	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	0.008760		118	118	118	118	118	118	118	118	118	118	118	118	1,416
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,441	2,435	2,427	2,421	2,414	2,408	2,402	2,395	2,389	2,381	2,375	2,368	28,856
	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			2,441	2,435	2,427	2,421	2,414	2,408	2,402	2,395	2,389	2,381	2,375	2,368	28,856

For Project: CAIR CTs - BARTOW (Project 7.2b)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	
3	Less: Accumulated Depreciation		(19,273)	(19,798)	(20,323)	(20,848)	(21,373)	(21,898)	(22,423)	(22,948)	(23,473)	(23,998)	(24,523)	(25,048)	(25,573)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$256,074	255,549	255,024	254,499	253,974	253,449	252,924	252,399	251,874	251,349	250,824	250,299	249,774	
6	Average Net Investment			255,812	255,287	254,762	254,237	253,712	253,187	252,662	252,137	251,612	251,087	250,562	250,037	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.38%		2,206	2,201	2,196	2,192	2,187	2,183	2,178	2,174	2,169	2,165	2,160	2,156	$26,167
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.85%		608	607	606	604	603	602	601	599	598	597	596	594	7,215
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.29%		525	525	525	525	525	525	525	525	525	525	525	525	6,300
	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	0.009130		209	209	209	209	209	209	209	209	209	209	209	209	2,508
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			3,548	3,542	3,536	3,530	3,524	3,519	3,513	3,507	3,501	3,496	3,490	3,484	42,190
	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			3,548	3,542	3,536	3,530	3,524	3,519	3,513	3,507	3,501	3,496	3,490	3,484	42,190

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.2 Recap
JANUARY 2010 - DECEMBER 2010

For Project: CAIR CTs - BAYBORO (Project 7.2c)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	
3	Less: Accumulated Depreciation		(11,079)	(11,772)	(12,465)	(13,158)	(13,851)	(14,544)	(15,237)	(15,930)	(16,623)	(17,316)	(18,009)	(18,702)	(19,395)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$187,909	187,216	186,523	185,830	185,137	184,444	183,751	183,058	182,365	181,672	180,979	180,286	179,593	
6	Average Net Investment			187,563	186,870	186,177	185,484	184,791	184,098	183,405	182,712	182,019	181,326	180,633	179,940	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		1,617	1,611	1,605	1,599	1,593	1,587	1,581	1,575	1,569	1,563	1,557	1,551	$19,008
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.85%		446	444	443	441	439	438	436	434	433	431	429	428	5,242
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	4.18%		693	693	693	693	693	693	693	693	693	693	693	693	8,316
	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	0.009138		151	151	151	151	151	151	151	151	151	151	151	151	1,812
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,907	2,899	2,892	2,884	2,876	2,869	2,861	2,853	2,846	2,838	2,830	2,823	34,378
	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			2,907	2,899	2,892	2,884	2,876	2,869	2,861	2,853	2,846	2,838	2,830	2,823	34,378

For Project: CAIR CTs - DeBARY (Project 7.2d)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	
3	Less: Accumulated Depreciation		(6,375)	(6,657)	(6,939)	(7,221)	(7,503)	(7,785)	(8,067)	(8,349)	(8,631)	(8,913)	(9,195)	(9,477)	(9,759)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$81,292	81,010	80,728	80,446	80,164	79,882	79,600	79,318	79,036	78,754	78,472	78,190	77,908	
6	Average Net Investment			81,151	80,869	80,587	80,305	80,023	79,741	79,459	79,177	78,895	78,613	78,331	78,049	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		700	697	695	692	690	688	685	683	680	678	675	673	$8,236
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.85%		193	192	192	191	190	190	189	188	188	187	186	186	2,272
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.86%		282	282	282	282	282	282	282	282	282	282	282	282	3,384
	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	0.009270		68	68	68	68	68	68	68	68	68	68	68	68	816
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,243	1,239	1,237	1,233	1,230	1,228	1,224	1,221	1,218	1,215	1,211	1,209	14,708
	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			1,243	1,239	1,237	1,233	1,230	1,228	1,224	1,221	1,218	1,215	1,211	1,209	14,708

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.2 Recap
JANUARY 2010 - DECEMBER 2010

For Project: CAIR CTs - HIGGINS (Project 7.2e)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	
3	Less: Accumulated Depreciation		(6,697)	(6,539)	(6,381)	(6,223)	(6,065)	(5,907)	(5,749)	(5,591)	(5,433)	(5,275)	(5,117)	(4,959)	(4,801)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$338,793	338,951	339,109	339,267	339,425	339,583	339,741	339,899	340,057	340,215	340,373	340,531	340,689	
6	Average Net Investment			338,872	339,030	339,188	339,346	339,504	339,662	339,820	339,978	340,136	340,294	340,452	340,610	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		2,922	2,923	2,924	2,926	2,927	2,928	2,930	2,931	2,933	2,934	2,935	2,937	$35,150
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.85%		806	806	806	807	807	808	808	808	809	809	809	810	9,693
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	-0.55%		(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			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	0.009130		263	263	263	263	263	263	263	263	263	263	263	263	3,156
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			3,833	3,834	3,835	3,838	3,839	3,841	3,843	3,844	3,847	3,848	3,849	3,852	46,103
	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			3,833	3,834	3,835	3,838	3,839	3,841	3,843	3,844	3,847	3,848	3,849	3,852	46,103

For Project: CAIR CTs - INTERCESSION CITY (Project 7.2f)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	
3	Less: Accumulated Depreciation		(19,459)	(22,305)	(25,151)	(27,997)	(30,843)	(33,689)	(36,535)	(39,381)	(42,227)	(45,073)	(47,919)	(50,765)	(53,611)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$330,126	327,279	324,433	321,587	318,741	315,895	313,049	310,203	307,357	304,511	301,665	298,819	295,973	
6	Average Net Investment			328,702	325,856	323,010	320,164	317,318	314,472	311,626	308,780	305,934	303,088	300,242	297,396	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		2,834	2,809	2,785	2,760	2,736	2,711	2,687	2,662	2,638	2,613	2,589	2,564	$32,388
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.85%		781	775	768	761	754	748	741	734	727	721	714	707	8,931
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	9.77%		2,846	2,846	2,846	2,846	2,846	2,846	2,846	2,846	2,846	2,846	2,846	2,846	34,152
	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	0.007740		225	225	225	225	225	225	225	225	225	225	225	225	2,700
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			6,686	6,655	6,624	6,592	6,561	6,530	6,499	6,467	6,436	6,405	6,374	6,342	78,171
	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			6,686	6,655	6,624	6,592	6,561	6,530	6,499	6,467	6,436	6,405	6,374	6,342	78,171

CPD

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.2 Recap
JANUARY 2010 - DECEMBER 2010

For Project: CAIR CTs - TURNER (Project 7.2g)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	
3	Less: Accumulated Depreciation		(7,767)	(7,854)	(7,941)	(8,028)	(8,115)	(8,202)	(8,289)	(8,376)	(8,463)	(8,550)	(8,637)	(8,724)	(8,811)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$126,245	126,158	126,071	125,984	125,897	125,810	125,723	125,636	125,549	125,462	125,375	125,288	125,201	
6	Average Net Investment			126,201	126,114	126,027	125,940	125,853	125,766	125,679	125,592	125,505	125,418	125,331	125,244	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		1,088	1,087	1,087	1,086	1,085	1,084	1,084	1,083	1,082	1,081	1,081	1,080	$13,008
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.85%		300	300	300	299	299	299	299	299	298	298	298	298	3,587
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	0.78%		87	87	87	87	87	87	87	87	87	87	87	87	1,044
	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	0.009270		104	104	104	104	104	104	104	104	104	104	104	104	1,248
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,579	1,578	1,578	1,576	1,575	1,574	1,574	1,573	1,571	1,570	1,570	1,569	18,887
	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			1,579	1,578	1,578	1,576	1,575	1,574	1,574	1,573	1,571	1,570	1,570	1,569	18,887

For Project: CAIR CTs - SUWANNEE (Project 7.2h)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	
3	Less: Accumulated Depreciation		(15,822)	(16,525)	(17,228)	(17,931)	(18,634)	(19,337)	(20,040)	(20,743)	(21,446)	(22,149)	(22,852)	(23,555)	(24,258)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$365,738	365,035	364,332	363,629	362,926	362,223	361,520	360,817	360,114	359,411	358,708	358,005	357,302	
6	Average Net Investment			365,386	364,683	363,980	363,277	362,574	361,871	361,168	360,465	359,762	359,059	358,356	357,653	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		3,150	3,144	3,138	3,132	3,126	3,120	3,114	3,108	3,102	3,096	3,090	3,084	$37,404
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.85%		869	867	865	864	862	860	859	857	855	854	852	850	10,314
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.21%		703	703	703	703	703	703	703	703	703	703	703	703	8,436
	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	0.007850		250	250	250	250	250	250	250	250	250	250	250	250	3,000
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			4,972	4,964	4,956	4,949	4,941	4,933	4,926	4,918	4,910	4,903	4,895	4,887	59,154
	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			4,972	4,964	4,956	4,949	4,941	4,933	4,926	4,918	4,910	4,903	4,895	4,887	59,154

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. __(TGF-4)

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2010 - DECEMBER 2010

For Project: CAIR/CAMR Crystal River AFUDC - Access Road and Vehicle Barrier System (Project 7.4a)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	15,490,382	
3	Less: Accumulated Depreciation		(863,405)	(893,224)	(923,043)	(952,862)	(982,681)	(1,012,500)	(1,042,319)	(1,072,138)	(1,101,957)	(1,131,776)	(1,161,595)	(1,191,414)	(1,221,233)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$14,626,977	14,597,158	14,567,339	14,537,520	14,507,701	14,477,882	14,448,063	14,418,244	14,388,425	14,358,606	14,328,787	14,298,968	14,269,149	
6	Average Net Investment			14,612,068	14,582,249	14,552,430	14,522,611	14,492,792	14,462,973	14,433,154	14,403,335	14,373,516	14,343,697	14,313,878	14,284,059	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		125,980	125,723	125,466	125,209	124,952	124,695	124,438	124,181	123,924	123,667	123,409	123,152	$1,494,796
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		34,740	34,669	34,598	34,528	34,457	34,386	34,315	34,244	34,173	34,102	34,031	33,960	412,203
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.31%		29,819	29,819	29,819	29,819	29,819	29,819	29,819	29,819	29,819	29,819	29,819	29,819	357,828
	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	0.010480		13,528	13,528	13,528	13,528	13,528	13,528	13,528	13,528	13,528	13,528	13,528	13,528	162,336
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			204,067	203,739	203,411	203,084	202,756	202,428	202,100	201,772	201,444	201,116	200,787	200,459	2,427,163
	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			204,067	203,739	203,411	203,084	202,756	202,428	202,100	201,772	201,444	201,116	200,787	200,459	2,427,163

For Project: CAIR/CAMR Crystal River AFUDC - Low Nox Burner CR4 (Project 7.4b)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	10,421,981	
3	Less: Accumulated Depreciation		(271,659)	(316,560)	(361,461)	(406,362)	(451,263)	(496,164)	(541,065)	(585,966)	(630,867)	(675,768)	(720,669)	(765,570)	(810,471)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$10,150,322	10,105,421	10,060,520	10,015,619	9,970,718	9,925,817	9,880,916	9,836,015	9,791,114	9,746,213	9,701,312	9,656,411	9,611,510	
6	Average Net Investment			10,127,871	10,082,970	10,038,069	9,993,168	9,948,268	9,903,367	9,858,466	9,813,565	9,768,664	9,723,763	9,678,862	9,633,961	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		87,319	86,932	86,545	86,158	85,771	85,384	84,996	84,609	84,222	83,835	83,448	83,061	$1,022,280
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		24,079	23,972	23,866	23,759	23,652	23,545	23,439	23,332	23,225	23,118	23,011	22,905	281,903
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	5.17%		44,901	44,901	44,901	44,901	44,901	44,901	44,901	44,901	44,901	44,901	44,901	44,901	538,812
	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	0.010480		9,102	9,102	9,102	9,102	9,102	9,102	9,102	9,102	9,102	9,102	9,102	9,102	109,224
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			165,401	164,907	164,414	163,920	163,426	162,932	162,438	161,944	161,450	160,956	160,462	159,969	1,952,219
	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			165,401	164,907	164,414	163,920	163,426	162,932	162,438	161,944	161,450	160,956	160,462	159,969	1,952,219

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. __ (TGF-4)
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CPD

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2010 - DECEMBER 2010

For Project: CAIR/CAMR Crystal River AFUDC - Selective Catalytic Reduction CR5 (Project 7.4c)
(in Dollars)

Line Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	End of Period Total
1 Investments															
a. Expenditures/Additions			20,000	20,000	20,000	20,000	20,000	20,000	20,000	$0	$0	$0	$0	$0	$140,000
b. Clearings to Plant			20,000	20,000	20,000	20,000	20,000	20,000	20,000	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		$92,494,737	92,514,737	92,534,737	92,554,737	92,574,737	92,594,737	92,614,737	92,634,737	92,634,737	92,634,737	92,634,737	92,634,737	92,634,737	
3 Less: Accumulated Depreciation		(1,414,831)	(1,813,115)	(2,211,785)	(2,610,542)	(3,009,385)	(3,408,314)	(3,807,329)	(4,206,430)	(4,605,531)	(5,004,632)	(5,403,733)	(5,802,834)	(6,201,935)	
4 CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$91,069,206	90,701,622	90,322,952	89,944,195	89,565,352	89,186,423	88,807,408	88,428,307	88,029,206	87,630,105	87,231,004	86,831,903	86,432,802	
6 Average Net Investment			90,890,914	90,512,287	90,133,573	89,754,773	89,375,887	88,996,915	88,617,857	88,228,756	87,829,655	87,430,554	87,031,453	86,632,352	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	10.35%		783,631	780,367	777,102	773,836	770,569	767,302	764,034	760,679	757,239	753,797	750,358	746,915	$9,185,828
b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		216,093	215,193	214,293	213,392	212,491	211,590	210,689	209,764	208,815	207,866	206,917	205,968	2,533,071
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	5.17%		398,584	398,670	398,757	398,843	398,929	399,015	399,101	399,101	399,101	399,101	399,101	399,101	4,787,404
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	0.010480		80,796	80,814	80,831	80,849	80,866	80,884	80,901	80,901	80,901	80,901	80,901	80,901	970,446
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			1,479,104	1,475,044	1,470,983	1,466,920	1,462,855	1,458,791	1,454,725	1,450,445	1,446,055	1,441,665	1,437,275	1,432,885	17,478,747
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			1,479,104	1,475,044	1,470,983	1,466,920	1,462,855	1,458,791	1,454,725	1,450,445	1,446,055	1,441,665	1,437,275	1,432,885	17,478,747

For Project: CAIR/CAMR Crystal River AFUDC - FGD Common (Project 7.4d)
(in Dollars)

Line Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	End of Period Total
1 Investments															
a. Expenditures/Additions			1,540,000	2,041,798	2,589,985	1,100,000	1,545,160	1,500,000	500,000	254,844	$0	$0	$0	$0	$11,071,785
b. Clearings to Plant			1,540,000	2,041,798	2,589,985	1,100,000	1,545,160	1,500,000	500,000	254,844	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		$634,421,721	635,961,721	638,003,517	640,593,502	641,693,502	643,238,662	644,738,662	645,238,662	645,493,506	645,493,506	645,493,506	645,493,506	645,493,506	
3 Less: Accumulated Depreciation		(748,089)	(3,488,024)	(6,236,756)	(8,996,646)	(11,761,276)	(14,532,563)	(17,310,312)	(20,090,215)	(22,871,216)	(25,652,217)	(28,433,218)	(31,214,219)	(33,995,220)	
4 CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$633,673,632	632,473,697	631,766,761	631,596,856	629,932,226	628,706,099	627,428,350	625,148,447	622,622,290	619,841,289	617,060,288	614,279,287	611,498,286	
6 Average Net Investment			633,073,665	632,120,229	631,681,809	630,764,541	629,319,163	628,067,225	626,288,399	623,885,369	621,231,790	618,450,789	615,669,788	612,888,787	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	10.35%		5,456,150	5,449,930	5,446,150	5,438,242	5,425,780	5,414,988	5,399,650	5,378,932	5,356,053	5,332,077	5,308,100	5,284,123	$64,692,173
b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		1,505,133	1,502,868	1,501,824	1,499,643	1,496,206	1,493,230	1,489,001	1,483,287	1,476,979	1,470,367	1,463,755	1,457,143	17,839,434
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	5.17%		2,739,936	2,748,732	2,759,890	2,764,630	2,771,287	2,777,749	2,779,903	2,781,001	2,781,001	2,781,001	2,781,001	2,781,001	33,247,131
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	0.010480		555,407	557,190	559,452	560,412	561,762	563,072	563,508	563,731	563,731	563,731	563,731	563,731	6,739,458
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			10,256,625	10,258,718	10,267,316	10,262,927	10,255,035	10,249,037	10,232,062	10,206,951	10,177,764	10,147,176	10,116,587	10,085,998	122,518,196
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			10,256,625	10,258,718	10,267,316	10,262,927	10,255,035	10,249,037	10,232,062	10,206,951	10,177,764	10,147,176	10,116,587	10,085,998	122,518,196

CPD.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2010 - DECEMBER 2010

For Project: CAIR/CAMR Crystal River AFUDC - SCR Common Items (Project 7.4e)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$69,831,473	69,831,473	69,831,473	69,831,473	69,831,473	69,831,473	69,831,473	69,831,473	69,831,473	69,831,473	69,831,473	69,831,473.14	69,831,473	
3	Less: Accumulated Depreciation		(906,773)	(1,206,830)	(1,507,487)	(1,808,344)	(2,109,201)	(2,410,058)	(2,710,915)	(3,011,772)	(3,312,629)	(3,613,486)	(3,914,343)	(4,215,200)	(4,516,057)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$68,925,700	68,624,643	68,323,986	68,023,129	67,722,272	67,421,415	67,120,558	66,819,701	66,518,844	66,217,987	65,917,130	65,616,273	65,315,416	
6	Average Net Investment			68,775,272	68,474,415	68,173,558	67,872,701	67,571,844	67,270,987	66,970,130	66,669,273	66,368,416	66,067,559	65,766,702	65,465,845	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.38%		592,957	590,364	587,770	585,176	582,582	579,988	577,394	574,800	572,206	569,612	567,019	564,425	$6,944,293
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.88%		163,513	162,798	162,083	161,367	160,652	159,937	159,221	158,506	157,791	157,076	156,360	155,645	1,914,949
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	5.17%		300,857	300,857	300,857	300,857	300,857	300,857	300,857	300,857	300,857	300,857	300,857	300,857	3,610,284
	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	0.010480		60,986	60,986	60,986	60,986	60,986	60,986	60,986	60,986	60,986	60,986	60,986	60,986	731,832
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,118,313	1,115,005	1,111,696	1,108,388	1,105,077	1,101,768	1,098,458	1,095,149	1,091,840	1,088,531	1,085,222	1,081,913	13,201,358
	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			1,118,313	1,115,005	1,111,696	1,108,388	1,105,077	1,101,768	1,098,458	1,095,149	1,091,840	1,088,531	1,085,222	1,081,913	13,201,358

For Project: CAIR/CAMR Crystal River AFUDC - Flue Gas Desulfurization CR5 (Project 7.4f)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	1,226,404	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,226,404
	b. Clearings to Plant			0	1,226,404	0	0	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		$135,013,655	135,013,655	136,240,059	136,240,059	136,240,059	136,240,059	136,240,059	136,240,059	136,240,059	136,240,059	136,240,059	136,240,059	136,240,059	
3	Less: Accumulated Depreciation		(159,204)	(740,888)	(1,327,856)	(1,914,824)	(2,501,792)	(3,088,760)	(3,675,728)	(4,262,696)	(4,849,664)	(5,436,632)	(6,023,600)	(6,610,568)	(7,197,536)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$134,854,452	134,272,768	134,912,204	134,325,236	133,738,268	133,151,300	132,564,332	131,977,364	131,390,396	130,803,428	130,216,460	129,629,492	129,042,524	
6	Average Net Investment			134,563,610	134,592,486	134,618,720	134,031,752	133,444,784	132,857,816	132,270,848	131,683,880	131,096,912	130,509,944	129,922,976	129,336,008	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.38%		1,160,183	1,160,412	1,160,638	1,155,577	1,150,516	1,145,456	1,140,395	1,135,335	1,130,274	1,125,213	1,120,153	1,115,092	$13,699,224
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.88%		319,925	319,994	320,056	318,660	317,265	315,869	314,474	313,078	311,683	310,287	308,892	307,496	3,777,679
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	5.17%		581,684	586,968	586,968	586,968	586,968	586,968	586,968	586,968	586,968	586,968	586,968	586,968	7,038,332
	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	0.010480		117,912	118,983	118,983	118,983	118,983	118,983	118,983	118,983	118,983	118,983	118,983	118,983	1,426,725
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,179,684	2,186,357	2,186,645	2,180,188	2,173,732	2,167,276	2,160,820	2,154,364	2,147,908	2,141,451	2,134,996	2,128,539	25,941,960
	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			2,179,684	2,186,357	2,186,645	2,180,188	2,173,732	2,167,276	2,160,820	2,154,364	2,147,908	2,141,451	2,134,996	2,128,539	25,941,960

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2010 - DECEMBER 2010
For Project: CAIR/CAMR Crystal River AFUDC - CR5 Sootblower & Intelligent Soot Blowing controls (Project 7.4g)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$929,220	929,220	929,220	929,220	929,220	929,220	929,220	929,220	929,220	929,220	929,220	929,220	929,220	
3	Less: Accumulated Depreciation		(1,096)	(5,099)	(9,102)	(13,105)	(17,108)	(21,111)	(25,114)	(29,117)	(33,120)	(37,123)	(41,126)	(45,129)	(49,132)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$928,125	924,122	920,119	916,116	912,113	908,110	904,107	900,104	896,101	892,098	888,095	884,092	880,089	
6	Average Net Investment			926,123	922,120	918,117	914,114	910,111	906,108	902,105	898,102	894,099	890,096	886,093	882,090	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.38%		7,985	7,950	7,916	7,881	7,847	7,812	7,778	7,743	7,709	7,674	7,640	7,605	$93,540
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		2,202	2,192	2,183	2,173	2,164	2,154	2,145	2,135	2,126	2,116	2,107	2,097	25,794
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	5.17%		4,003	4,003	4,003	4,003	4,003	4,003	4,003	4,003	4,003	4,003	4,003	4,003	48,036
	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	0.010480		812	812	812	812	812	812	812	812	812	812	812	812	9,744
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			15,002	14,957	14,914	14,869	14,826	14,781	14,738	14,693	14,650	14,605	14,562	14,517	177,114
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			15,002	14,957	14,914	14,869	14,826	14,781	14,738	14,693	14,650	14,605	14,562	14,517	177,114

For Project: CAIR/CAMR Crystal River AFUDC - CR4 Sootblower & Intelligent Soot Blowing controls (Project 7.4h)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$ 949,211	$0	$0	$0	$0	$0	$0	$0	$949,211
	b. Clearings to Plant			0	0	0	0	949,211	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	949,211	949,211	949,211	949,211	949,211	949,211	949,211	949,211	
3	Less: Accumulated Depreciation		-	0	0	0	0	(2,045)	(6,135)	(10,225)	(14,315)	(18,405)	(22,495)	(26,585)	(30,675)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$0	0	0	0	0	947,166	943,076	938,986	934,896	930,806	926,716	922,626	918,536	
6	Average Net Investment			0	0	0	0	473,583	945,121	941,031	936,941	932,851	928,761	924,671	920,581	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.38%		0	0	0	0	4,063	8,149	8,113	8,078	8,043	8,007	7,972	7,937	$60,362
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		0	0	0	0	1,126	2,247	2,237	2,228	2,218	2,208	2,198	2,189	16,651
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	5.17%		0	0	0	0	2,045	4,090	4,090	4,090	4,090	4,090	4,090	4,090	30,675
	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	0.010480		0	0	0	0	829	829	829	829	829	829	829	829	6,632
	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	8,063	15,315	15,269	15,225	15,180	15,134	15,089	15,045	114,340
	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	8,063	15,315	15,269	15,225	15,180	15,134	15,089	15,045	114,340

CPD

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2010 - DECEMBER 2010

For Project: CAIR/CAMR Crystal River AFUDC - CR4 SCR (Project 7.4l)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$108,219,363	1,435,613	1,632,028	195,609	183,116	174,307	174,129	174,076	$112,188,441
	b. Clearings to Plant			0	0	0	0	108,219,363	1,435,613	1,632,028	195,609	183,116	174,307	174,129	174,076	
	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	108,219,363	109,654,976	111,287,004	111,482,613	111,665,929	111,840,236	112,014,364	112,188,441	
3	Less: Accumulated Depreciation		-	0	0	0	0	(233,123)	(705,553)	(1,165,015)	(1,666,320)	(2,146,414)	(2,626,259)	(3,110,854)	(3,594,199)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$0	0	0	0	0	107,986,241	108,949,423	110,101,990	109,817,494	109,519,515	109,211,977	108,903,511	108,594,242	
6	Average Net Investment			0	0	0	0	53,993,120	108,467,832	109,525,707	109,959,742	109,668,504	109,365,746	109,057,744	108,748,877	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.38%		0	0	0	0	465,511	935,173	944,294	948,038	945,525	942,915	940,260	937,597	$7,059,311
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		0	0	0	0	126,369	257,882	260,397	261,428	260,737	260,017	259,235	258,550	1,946,866
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	5.17%		0	0	0	0	233,123	472,430	479,462	480,305	481,094	481,845	482,595	483,345	3,594,199
	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	0.010480		0	0	0	0	94,512	95,765	97,191	97,362	97,522	97,674	97,826	97,978	775,830
	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	921,515	1,761,250	1,781,344	1,787,132	1,784,878	1,782,451	1,779,966	1,777,470	13,376,006
	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	921,515	1,761,250	1,781,344	1,787,132	1,784,878	1,782,451	1,779,966	1,777,470	13,376,006

For Project: CAIR/CAMR Crystal River AFUDC - CR4 FGD (Project 7.4l)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$138,386,946	478,327	1,779,294	239,128	223,627	212,870	212,652	212,588	$141,745,432
	b. Clearings to Plant			0	0	0	0	138,386,946	478,327	1,779,294	239,128	223,627	212,870	212,652	212,588	
	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	138,386,946	138,865,273	140,644,566	140,883,695	141,107,322	141,320,191	141,532,844	141,745,432	
3	Less: Accumulated Depreciation		-	0	0	0	0	(298,109)	(896,387)	(1,502,331)	(2,109,305)	(2,717,242)	(3,326,096)	(3,935,867)	(4,546,554)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$0	0	0	0	0	138,088,838	137,968,886	139,142,236	138,774,390	138,390,080	137,994,096	137,596,977	137,198,878	
6	Average Net Investment			0	0	0	0	69,044,419	138,028,862	138,555,561	138,958,313	138,582,235	138,192,088	137,795,537	137,397,928	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.38%		0	0	0	0	595,278	1,190,039	1,194,580	1,198,052	1,194,810	1,191,446	1,188,027	1,184,599	$8,936,831
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		0	0	0	0	164,153	328,164	329,416	330,375	329,479	328,552	327,609	326,664	2,464,410
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	5.17%		0	0	0	0	298,109	598,278	605,944	606,974	607,937	608,854	609,771	610,687	4,546,554
	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	0.010480		0	0	0	0	120,858	121,278	122,830	123,035	123,234	123,420	123,605	123,791	962,052
	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	1,178,398	2,237,757	2,252,770	2,258,437	2,255,460	2,252,272	2,249,012	2,245,741	16,929,847
	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	1,178,398	2,237,757	2,252,770	2,258,437	2,255,460	2,252,272	2,249,012	2,245,741	16,929,847

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. ___ (TGF-4)

CPD

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2010 - DECEMBER 2010

For Project: CAIR/CAMR Crystal River AFUDC - Gypsum Handling (Project 7.4k)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-10	Projected Feb-10	Projected Mar-10	Projected Apr-10	Projected May-10	Projected Jun-10	Projected Jul-10	Projected Aug-10	Projected Sep-10	Projected Oct-10	Projected Nov-10	Projected Dec-10	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		$20,873,018	20,873,018	20,873,018	20,873,018	20,873,018	20,873,018	20,873,018	20,873,018	20,873,018	20,873,018	20,873,018	20,873,018	20,873,018	
3	Less: Accumulated Depreciation		(44,964)	(134,892)	(224,820)	(314,748)	(404,676)	(494,604)	(584,532)	(674,460)	(764,388)	(854,316)	(944,244)	(1,034,172)	(1,124,100)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$20,828,054	20,738,126	20,648,198	20,558,270	20,468,342	20,378,414	20,288,486	20,198,558	20,108,630	20,018,702	19,928,774	19,838,846	19,748,918	
6	Average Net Investment			20,783,090	20,693,162	20,603,234	20,513,306	20,423,378	20,333,450	20,243,522	20,153,594	20,063,666	19,973,738	19,883,810	19,793,882	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	10.35%		179,185	178,410	177,634	176,859	176,084	175,308	174,533	173,758	172,982	172,207	171,432	170,656	$2,099,045
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		49,412	49,198	48,984	48,770	48,557	48,343	48,129	47,915	47,701	47,488	47,274	47,060	576,831
	c. Other			114,545	0	0	0	0	0	0	0	0	0	0	0	114,545
8	Investment Expenses															
	a. Depreciation	5.17%		89,928	89,928	89,928	89,928	89,928	89,928	89,928	89,928	89,928	89,928	89,928	89,928	1,079,136
	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	0.010480		18,229	18,229	18,229	18,229	18,229	18,229	18,229	18,229	18,229	18,229	18,229	18,229	218,748
	e. Other			83,193	0	0	0	0	0	0	0	0	0	0	0	83,193
9	Total System Recoverable Expenses (Lines 7 + 8)			514,492	335,765	334,775	333,786	332,798	331,808	330,819	329,830	328,840	327,852	326,863	325,873	4,153,501
	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			514,492	335,765	334,775	333,786	332,798	331,808	330,819	329,830	328,840	327,852	326,863	325,873	4,153,501

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. __ (TGF-4)
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Witness: T.G. Foster
Exhibit__(TGF -3)

PROGRESS ENERGY FLORIDA, INC.
ENVIRONMENTAL COST RECOVERY
COMMISSION FORMS 42-1P THROUGH 42-7P

JANUARY 2010 - DECEMBER 2010
Calculation of the Projected Period Amount
January through December 2010
DOCKET NO. 090007-EI

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to be Recovered
For the Projected Period
JANUARY 2010 - DECEMBER 2010
(in Dollars)

Form 42-1P

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)	$31,802,843	$725,904	$9,858,302	$4,532,180	$46,919,229
b	Projected Capital Projects (Form 42-3P, Lines 7 through 9)	204,080,320	0	7,083	2,582,417	206,669,820
c	Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b)	$235,883,163	$725,904	$9,865,385	$7,114,597	$253,589,049
2	True-up for Estimated Over/(Under) Recovery for the current period January 2009 - December 2009 (Form 42-2E, Line 5 + 6 + 10)	18,198,931	579,224	3,425,915	1,871,512	$24,075,581
3	Final True-up for the period January 2008 - December 2008 (Form 42-1A, Line 3)	(1,372,802)	(187,999)	(2,347,539)	(412,265)	($4,320,606)
4	Total Jurisdictional Amount to Be Recovered/(Refunded) in the Projection period January 2009 - December 2009 (Line 1 - Line 2 - Line 3)	$219,057,035	$334,679	$8,787,009	$5,655,350	$233,834,074
5	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier of 1.00072)	$219,214,756	$334,920	$8,793,336	$5,659,422	$234,002,435

Form 42-2P

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010

O&M Activities
(in Dollars)

Line	Description	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	End of Period Total
1	Description of O&M Activities													
	1 Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$ 88,625	$ 88,625	$ 88,625	$ 88,625	$ 88,625	$ 88,625	$ 88,625	$ 88,625	$ 88,625	$ 88,625	$ 88,625	$ 88,625	$1,063,496
	1a Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	84,326	84,326	84,326	84,326	84,326	84,326	84,326	84,326	84,326	84,325	84,326	84,326	1,011,915
	2 Distribution System Environmental Investigation, Remediation, and Pollution Prevention	1,282,200	1,372,000	1,214,200	1,092,800	1,039,600	831,800	756,800	555,000	313,200	313,200	108,000	-	8,880,800
	3 Pipeline Integrity Management, Review/Update Plan and Risk Assessments - Intm	145,429	120,429	120,429	120,429	120,429	120,429	120,429	64,000	64,000	74,000	74,000	74,000	1,218,000
	4 Above Ground Tank Secondary Containment - Pkg	0	0	0	0	0	0	0	0	0	0	0	0	0
	5 SO2 and NOX Emissions Allowances - Energy	997,263	670,619	599,866	615,537	1,264,469	1,160,949	1,063,837	1,138,392	1,002,939	664,810	504,759	524,189	10,207,830
	6 Phase II Cooling Water Intake 316(b) - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
	6a Phase II Cooling Water Intake 316(b) - Intm	0	0	0	0	0	0	0	0	0	0	0	0	0
	7.2 CAIR - Peaking	0	0	16,825	0	0	16,825	0	0	16,825	0	0	16,825	67,300
	7.4 CAIR Crystal River AFUDC - Base	562,016	562,016	562,016	562,016	562,016	562,016	562,016	562,016	562,016	562,016	562,016	562,016	6,744,196
	7.4 CAIR Crystal River AFUDC - Energy	696,037	632,327	955,526	894,414	706,438	1,502,514	1,465,862	1,986,179	1,923,610	1,919,454	1,571,213	2,041,688	16,295,261
	7.4 CAIR Crystal River - A&G	1,298	1,298	1,298	1,947	1,298	1,298	1,298	1,298	1,298	1,947	1,298	1,298	16,871
	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	150	150	150	150	150	150	150	150	150	150	150	150	1,800
	11 Modular Cooling Towers - Base	0	0	0	0	0	834,188	834,188	834,188	1,038,867	204,679	204,679	204,679	4,155,466
	12 Greenhouse Gas Inventory and Reporting - Energy	0	0	0	0	0	0	3,750	3,750	3,750	3,750	3,750	3,750	22,500
	13 Macrury Total Maximum Daily Loads Monitoring - Energy	0	0	9,019	0	0	9,019	0	0	9,019	0	0	9,020	36,077
2	Total of O&M Activities	3,867,343	3,531,790	3,652,279	3,460,244	3,867,350	5,212,138	4,983,281	5,317,924	5,108,825	3,916,957	3,202,818	3,610,566	$49,721,312
3	Recoverable Costs Allocated to Energy	1,693,300	1,302,946	1,564,411	1,509,951	1,970,906	2,672,482	2,533,449	3,128,321	2,939,318	2,588,014	2,079,722	2,578,647	26,561,468
4	Recoverable Costs Allocated to Demand - Transm	88,625	88,625	88,625	88,625	88,625	88,625	88,625	88,625	88,625	88,625	88,625	88,625	1,063,496
	Recoverable Costs Allocated to Demand - Distrib	1,366,676	1,456,476	1,298,676	1,177,276	1,124,076	916,276	843,276	639,476	397,676	397,676	192,476	84,476	9,894,515
	Recoverable Costs Allocated to Demand - Prod-Base	562,016	562,016	562,016	562,016	562,016	1,396,204	1,396,204	1,396,204	1,600,883	766,695	766,695	766,695	10,899,662
	Recoverable Costs Allocated to Demand - Prod-Intm	145,429	120,429	120,429	120,429	120,429	120,429	120,429	64,000	64,000	74,000	74,000	74,000	1,218,000
	Recoverable Costs Allocated to Demand - Prod-Peaking	0	0	16,825	0	0	16,825	0	0	16,825	0	0	16,825	67,300
	Recoverable Costs Allocated to Demand - A&G	1,298	1,298	1,298	1,947	1,298	1,298	1,298	1,298	1,298	1,947	1,298	1,298	16,871
5	Retail Energy Jurisdictional Factor	0.96780	0.96220	0.96630	0.96650	0.96780	0.96960	0.96030	0.95790	0.95750	0.95620	0.95590	0.95990	
6	Retail Transmission Demand Jurisdictional Factor	0.68256	0.68256	0.68256	0.68256	0.68256	0.68256	0.68256	0.68255	0.68256	0.68256	0.68256	0.68256	
	Retail Distribution Demand Jurisdictional Factor	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	
	Retail Production Demand Jurisdictional Factor - Base	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	
	Retail Production Demand Jurisdictional Factor - Intm	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	
	Retail Production Demand Jurisdictional Factor - Peaking	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	
	Retail Production Demand Jurisdictional Factor - A&G	0.87583	0.87583	0.87583	0.87583	0.87583	0.87583	0.87583	0.87583	0.87583	0.87583	0.87583	0.87583	
7	Jurisdictional Energy Recoverable Costs (A)	1,638,775	1,253,695	1,511,690	1,459,368	1,907,443	2,591,238	2,432,871	2,996,619	2,814,397	2,474,659	1,988,006	2,475,243	25,544,004
8	Jurisdictional Demand Recoverable Costs - Transm (B)	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	60,492	725,904
	Jurisdictional Demand Recoverable Costs - Distrib (B)	1,361,674	1,451,146	1,293,923	1,172,967	1,119,962	912,923	840,190	637,136	396,221	396,221	191,772	84,167	9,858,302
	Jurisdictional Demand Recoverable Costs - Prod-Base (B)	515,195	515,195	515,195	515,195	515,195	1,279,887	1,279,887	1,279,887	1,467,513	702,821	702,821	702,821	9,991,612
	Jurisdictional Demand Recoverable Costs - Prod-Intm (B)	86,315	71,477	71,477	71,477	71,477	71,477	71,477	37,985	37,985	43,920	43,920	43,920	722,907
	Jurisdictional Demand Recoverable Costs - Prod-Peaking (B)	0	0	15,431	0	0	15,431	0	0	15,431	0	0	15,431	61,724
	Jurisdictional Demand Recoverable Costs - A&G (B)	1,137	1,137	1,137	1,705	1,137	1,137	1,137	1,137	1,137	1,705	1,137	1,137	14,776
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$3,663,588	$3,353,142	$3,469,345	$3,281,204	$3,675,706	$4,932,585	$4,686,054	$5,013,256	$4,793,176	$3,679,818	$2,988,148	$3,383,211	$48,919,229

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

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Progress Energy Florida
Witness: T.G. Foster
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
Capital Investment Projects-Recoverable Costs
(in Dollars)

Line	Description	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	End of Period Total
1	Description of Investment Projects (A)													
	3.1 Pipeline Integrity Management - Bartow/Anclote Pipeline-Intermediate	$51,083	$50,894	$50,725	$50,556	$50,388	$50,220	$50,051	$49,884	$49,714	$48,545	$49,376	$49,208	$601,626
	4.1 Above Ground Tank Secondary Containment - Peaking	148,001	149,816	155,400	158,683	158,360	157,840	157,317	156,796	156,272	155,750	155,229	154,709	1,864,373
	4.2 Above Ground Tank Secondary Containment - Base	28,359	28,310	28,258	28,209	28,158	28,108	28,058	28,008	27,957	27,906	27,855	27,806	336,994
	4.3 Above Ground Tank Secondary Containment - Intermediate	4,150	4,139	4,127	4,116	4,104	4,093	4,081	4,070	4,058	4,046	4,037	4,025	49,048
	5 SO2/NOX Emissions Allowances - Energy	361,809	352,636	345,850	338,965	328,626	315,287	303,053	290,941	279,164	269,993	263,560	257,901	3,707,585
	7.1 CAIR Anclote- Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0
	7.2 CAIR CT's - Peaking	27,209	27,146	27,085	27,023	26,960	26,902	26,842	26,778	26,718	26,656	26,594	26,534	322,447
	7.3 CAIR Crystal River - Base	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	38,160
	7.4 CAIR Crystal River AFUDC - Base	15,934,688	15,754,492	15,754,154	15,734,080	17,818,501	19,703,143	19,705,543	19,675,942	19,625,489	19,573,209	19,520,821	19,468,409	218,268,451
	7.4 CAIR Crystal River AFUDC - Energy	8,150	8,290	8,290	8,290	8,290	8,290	8,290	8,290	8,290	8,290	8,290	8,290	99,341
	9 Sea Turtle - Coastal Street Lighting -Distribution	462	480	510	536	553	583	609	625	654	678	695	724	7,109
	10.1 Underground Storage Tanks-Base	2,281	2,276	2,271	2,267	2,262	2,257	2,252	2,248	2,243	2,238	2,234	2,229	27,058
	10.2 Underground Storage Tanks-Intermediate	1,012	1,010	1,007	1,006	1,004	1,001	999	997	995	992	991	988	12,002
	11 Modular Cooling Towers - Base	13,893	13,772	13,650	13,527	13,408	13,283	13,162	13,040	12,918	12,796	12,674	12,552	158,673
	11.1 Crystal River Thermal Discharge Compliance Project - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
2	Total Investment Projects - Recoverable Costs	16,584,257	16,396,441	16,394,307	16,370,640	18,443,792	20,314,187	20,303,437	20,260,799	20,197,632	20,135,283	20,075,536	20,016,555	225,492,867
3	Recoverable Costs Allocated to Energy	369,959	360,926	353,940	347,255	336,916	323,577	311,343	299,231	287,454	278,283	271,850	266,191	3,806,926
	Recoverable Costs Allocated to Demand - Distribution	462	480	510	536	553	583	609	625	654	678	695	724	7,109
4	Recoverable Costs Allocated to Demand - Production - Base	15,982,401	15,802,030	15,801,513	15,781,263	17,865,507	19,749,971	19,752,195	19,722,418	19,671,767	19,619,331	19,566,764	19,514,176	216,829,336
	Recoverable Costs Allocated to Demand - Production - Intermediate	56,225	56,043	55,859	55,680	55,496	55,314	55,131	54,951	54,767	54,585	54,404	54,221	662,676
	Recoverable Costs Allocated to Demand - Production - Peaking	175,210	176,962	182,485	185,906	185,320	184,742	184,159	183,574	182,990	182,406	181,823	181,243	2,186,820
5	Retail Energy Jurisdictional Factor	0.96780	0.96220	0.96630	0.96650	0.96780	0.96960	0.96030	0.95790	0.95750	0.95620	0.95590	0.95990	
	Retail Distribution Demand Jurisdictional Factor	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	
6	Retail Demand Jurisdictional Factor - Production - Base	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	
	Retail Demand Jurisdictional Factor - Production - Intermediate	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	
	Retail Demand Jurisdictional Factor - Production - Peaking	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	
7	Jurisdictional Energy Recoverable Costs (B)	358,046	347,283	342,012	335,622	326,067	313,740	298,983	286,633	275,237	266,094	259,862	255,517	3,665,098
	Jurisdictional Demand Recoverable Costs - Distribution (B)	460	478	508	534	551	581	607	623	652	676	692	721	7,083
8	Jurisdictional Demand Recoverable Costs - Production - Base (C)	14,650,907	14,485,563	14,485,089	14,466,526	16,377,132	18,104,601	18,106,640	18,079,343	18,032,912	17,984,845	17,936,657	17,888,450	200,598,664
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	33,371	33,263	33,153	33,047	32,938	32,830	32,721	32,615	32,505	32,397	32,290	32,181	393,311
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	160,698	162,302	167,368	170,506	169,968	169,438	168,903	168,367	167,831	167,295	166,761	166,229	2,005,664
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$15,203,480	$15,028,689	$15,028,131	$15,008,235	$16,906,656	$18,621,190	$18,607,854	$18,567,581	$18,509,137	$18,451,307	$18,398,282	$18,343,098	$206,669,820

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

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. ___ (TGF-3)

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
Return on Capital Investments, Depreciation and Taxes
For Project: PIPELINE INTEGRITY MANAGEMENT - Bartow/Anclote Pipeline (Project 3.1)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	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		$3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	
3	Less: Accumulated Depreciation		(565,408)	(580,744)	(596,080)	(611,416)	(626,752)	(642,088)	(657,424)	(672,760)	(688,096)	(703,432)	(718,768)	(734,104)	(749,440)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$3,014,328	2,998,992	2,983,656	2,968,320	2,952,984	2,937,648	2,922,312	2,906,976	2,891,640	2,876,304	2,860,968	2,845,632	2,830,296	
6	Average Net Investment			3,006,660	2,991,324	2,975,988	2,960,652	2,945,316	2,929,980	2,914,644	2,899,308	2,883,972	2,868,636	2,853,300	2,837,964	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	10.35%		25,922	25,790	25,657	25,526	25,393	25,262	25,129	24,996	24,865	24,732	24,600	24,468	302,342
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.65%		7,148	7,111	7,075	7,039	7,002	6,965	6,929	6,893	6,856	6,820	6,783	6,747	83,368
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			15,336	15,336	15,336	15,336	15,336	15,336	15,336	15,336	15,336	15,336	15,336	15,336	184,032
	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)			2,657	2,657	2,657	2,657	2,657	2,657	2,657	2,657	2,657	2,657	2,657	2,657	31,884
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			51,063	50,894	50,725	50,558	50,388	50,220	50,051	49,884	49,714	49,545	49,378	49,208	601,628
	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			51,063	50,894	50,725	50,558	50,388	50,220	50,051	49,884	49,714	49,545	49,378	49,208	601,628
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)			0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352
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)			30,307	30,207	30,106	30,007	29,906	29,807	29,706	29,607	29,506	29,406	29,306	29,206	357,077
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$30,307	$30,207	$30,106	$30,007	$29,906	$29,807	$29,706	$29,607	$29,506	$29,406	$29,306	$29,206	$357,077

Notes:
(A) N/A
(B) Line 6 x 10.35% x 1/12. Based on ROE of 12.54%, weighted cost of equity component of capital structure of 6.35%, and statutory income tax rate of 38.575% (expansion factor of 1.6338). Based on proposal in PEF's rate case Dkt. 090079-EI.
(C) Depreciation calculated in Pipeline Integrity Management section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on proposal in PEF's rate case Dkt. 090079-EI.
(D) Lines 2 x 89% @ .009130 x 1/12 + 11%@ .007100 x 1/12. Ratio from Property Tax Administration Department, based on plant allocation reported and 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Progress Energy Florida
Witness: T.G. Foster
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
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 - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$156,000	$260,000	$223,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$638,000
	b. Clearings to Plant			0	0	1,513,040	0	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		$8,575,395	$8,575,395	$8,575,395	$10,088,435	$10,088,435	$10,088,435	$10,088,435	$10,088,435	$10,088,435	$10,088,435	$10,088,435	$10,088,435	$10,088,435	
3	Less: Accumulated Depreciation		(484,182)	(526,619)	(569,056)	(613,747)	(661,202)	(708,657)	(756,112)	(803,567)	(851,022)	(898,477)	(945,932)	(993,387)	(1,040,842)	
4	CWIP - Non-Interest Bearing		876,039	1,030,040	1,290,040	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$8,966,252	$9,078,816	$9,296,379	$9,474,688	$9,427,233	$9,379,778	$9,332,323	$9,284,868	$9,237,413	$9,189,958	$9,142,503	$9,095,048	$9,047,593	
6	Average Net Investment			$9,022,534	$9,187,597	$9,385,533	$9,450,960	$9,403,505	$9,356,050	$9,308,595	$9,261,140	$9,213,685	$9,166,230	$9,118,775	$9,071,320	0
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	10.35%		77,789	79,211	80,919	81,484	81,074	80,666	80,256	79,847	79,437	79,028	78,619	78,211	956,540
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		21,451	21,844	22,315	22,469	22,356	22,244	22,132	22,019	21,905	21,792	21,680	21,568	263,775
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			42,437	42,437	44,691	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	47,455	556,660
	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)			6,324	6,324	7,475	7,475	7,475	7,475	7,475	7,475	7,475	7,475	7,475	7,475	87,398
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			148,001	149,816	155,400	158,883	158,360	157,840	157,317	156,796	156,272	155,750	155,229	154,709	1,864,373
	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			148,001	149,816	155,400	158,883	158,360	157,840	157,317	156,796	156,272	155,750	155,229	154,709	1,864,373
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)			0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	
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)			135,741	137,405	142,527	145,721	145,241	144,765	144,285	143,807	143,326	142,848	142,370	141,893	1,709,928
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$135,741	$137,405	$142,527	$145,721	$145,241	$144,765	$144,285	$143,807	$143,326	$142,848	$142,370	$141,893	$1,709,928

Notes:
(A) N/A
(B) Line 6 x 10.35% x 1/12. Based on ROE of 12.54%, weighted cost of equity component of capital structure of 6.35%, and statutory income tax rate of 38.575% (expansion factor of 1.6338). Based on proposal in PEF's rate case Dkt. 090079-EI.
(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on proposal in PEF's rate case Dkt. 090079-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. __ (TGF-3)

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
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 - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	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		$2,068,790	$2,068,790	$2,068,790	$2,068,790	$2,068,790	$2,068,790	$2,068,790	$2,068,790	$2,068,790	$2,068,790	$2,068,790	$2,068,790	$2,068,790	
3	Less: Accumulated Depreciation		(67,969)	(72,539)	(77,109)	(81,679)	(86,249)	(90,819)	(95,389)	(99,959)	(104,529)	(109,099)	(113,669)	(118,239)	(122,809)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+ 3 + 4)		2,000,821	1,996,251	1,991,681	1,987,111	1,982,541	1,977,971	1,973,401	1,968,831	1,964,261	1,959,691	1,955,121	1,950,551	1,945,981	
6	Average Net Investment			$1,998,536	$1,993,966	$1,989,396	$1,984,826	$1,980,256	$1,975,686	$1,971,116	$1,966,546	$1,961,976	$1,957,406	$1,952,836	$1,948,266	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	10.35%		$17,231	$17,192	$17,152	$17,113	$17,073	$17,034	$16,995	$16,955	$16,916	$16,877	$16,836	$16,797	$204,171
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		$4,751	$4,741	$4,729	$4,719	$4,708	$4,697	$4,688	$4,678	$4,664	$4,654	$4,642	$4,632	$56,299
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			$4,570	$4,570	$4,570	$4,570	$4,570	$4,570	$4,570	$4,570	$4,570	$4,570	$4,570	$4,570	$54,840
	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)			1,807	1,807	1,807	1,807	1,807	1,807	1,807	1,807	1,807	1,807	1,807	1,807	21,684
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			28,359	28,310	28,258	28,209	28,158	28,108	28,058	28,008	27,957	27,908	27,855	27,806	336,994
	a. Recoverable Costs Allocated to Energy			-	-	-	-	-	-	-	-	-	-	-	-	-
	b. Recoverable Costs Allocated to Demand			28,359	28,310	28,258	28,209	28,158	28,108	28,058	28,008	27,957	27,908	27,855	27,806	336,994
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)			0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	
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)			25,996	25,951	25,904	25,859	25,812	25,766	25,720	25,675	25,628	25,583	25,534	25,489	308,919
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$25,996	$25,951	$25,904	$25,859	$25,812	$25,766	$25,720	$25,675	$25,628	$25,583	$25,534	$25,489	$308,919

Notes:
(A) N/A
(B) Line 6 x 10.35% x 1/12. Based on ROE of 12.54%, weighted cost of equity component of capital structure of 6.36%, and statutory income tax rate of 38.575% (expansion factor of 1.6338). Based on proposal in PEF's rate case Dkt. 090079-EI.
(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on proposal in PEF's rate case Dkt. 090079-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. ___ (TGF-3)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
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 - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	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		$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	$290,297	
3	*Less: Accumulated Depreciation*		(22,218)	(23,253)	(24,288)	(25,323)	(26,358)	(27,393)	(28,428)	(29,463)	(30,498)	(31,533)	(32,568)	(33,603)	(34,638)	
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)		$268,080	267,045	266,010	264,975	263,940	262,905	261,870	260,835	259,800	258,765	257,730	256,695	255,660	
6	Average Net Investment			267,562	266,527	265,492	264,457	263,422	262,387	261,352	260,317	259,282	258,247	257,212	256,177	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	10.35%		2,307	2,298	2,289	2,280	2,271	2,262	2,253	2,244	2,235	2,227	2,218	2,209	27,093
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		636	634	631	629	626	624	621	619	616	614	612	609	7,471
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			1,035	1,035	1,035	1,035	1,035	1,035	1,035	1,035	1,035	1,035	1,035	1,035	12,420
	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)			172	172	172	172	172	172	172	172	172	172	172	172	2,064
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			4,150	4,139	4,127	4,116	4,104	4,093	4,081	4,070	4,058	4,048	4,037	4,026	49,048
	a. Recoverable Costs Allocated to Energy			-	-	-	-	-	-	-	-	-	-	-	-	-
	b. Recoverable Costs Allocated to Demand			4,150	4,139	4,127	4,116	4,104	4,093	4,081	4,070	4,058	4,048	4,037	4,026	49,048
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)			0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	
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)*			2,463	2,457	2,449	2,443	2,436	2,429	2,422	2,416	2,409	2,403	2,396	2,389	29,111
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$2,463	$2,457	$2,449	$2,443	$2,436	$2,429	$2,422	$2,416	$2,409	$2,403	$2,396	$2,389	$29,111

Notes:
(A) N/A
(B) Line 6 x 10.35% x 1/12. Based on ROE of 12.64%, weighted cost of equity component of capital structure of 6.36%, and statutory income tax rate of 38.575% (expansion factor of 1.6338). Based on proposal in PEF's rate case Dkt. 090079-EI.
(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on proposal in PEF's rate case Dkt. 090079-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as 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

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. __ (TGF-3)

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
Schedule of Amortization and Return
Deferred Gain on Sales of Emissions Allowances (Project 5)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	Period Total
1	Working Capital Dr (Cr)															
	a. 1581001 SO_2 Emission Allowance Inventory		$6,902,143	$6,745,933	$6,636,274	$6,533,551	$6,426,299	$6,218,410	$6,078,016	$5,936,225	$5,770,051	$5,618,183	$5,504,402	$5,418,997	$5,333,889	$5,333,889
	b. 25401FL Auctioned SO_2 Allowance		(1,921,713)	(1,909,321)	(1,896,928)	(1,884,535)	(1,872,142)	(1,832,889)	(1,815,124)	(1,797,359)	(1,779,594)	(1,761,829)	(1,744,064)	(1,726,299)	(1,708,534)	(1,708,534)
	c. 1581002 NOX Emission Allowance Inventory		28,412,468	27,559,022	26,985,669	26,476,134	25,955,455	24,859,622	23,821,302	22,881,491	21,891,508	21,022,672	20,453,877	20,015,758	19,559,912	19,559,912
2	Total Working Capital		$33,392,897	32,395,634	31,725,015	31,125,149	30,509,612	29,245,143	28,084,194	27,020,358	25,881,966	24,879,026	24,214,216	23,709,457	23,185,267	23,185,267
3	Average Net Investment			32,894,266	32,060,325	31,425,082	30,817,381	29,877,378	28,664,669	27,552,276	26,451,162	25,380,496	24,546,621	23,961,836	23,447,362	
4	Return on Average Net Working Capital Balance															
	a. Equity Component Grossed Up For Taxes (A)	10.35%		283,603	276,413	270,937	265,697	257,593	247,137	237,547	228,053	218,822	211,633	206,691	202,155	$2,906,181
	b. Debt Component (Line 3 x 2.04% x 1/12)	2.85%		78,206	76,223	74,713	73,268	71,033	68,150	65,506	62,888	60,342	58,360	56,969	55,746	801,404
5	Total Return Component (B)			361,809	352,636	345,650	338,965	328,626	315,287	303,053	290,941	279,164	269,993	263,560	257,901	3,707,585
6	Expense Dr (Cr)															
	a. 5090001 SO_2 allowance expense			$159,210	$109,858	$102,724	$107,252	$207,889	$140,394	$141,791	$196,174	$151,869	$113,780	$84,405	$86,108	1,568,253
	b. 4074004 Amortization Expense			(12,393)	(12,393)	(12,393)	(12,393)	(38,254)	(17,765)	(17,765)	(17,765)	(17,765)	(17,765)	(17,765)	(17,765)	($213,160)
	c. 5090003 Nox allowance expense			853,446	573,354	509,525	820,678	1,095,834	1,038,320	939,611	969,063	868,836	568,795	438,119	455,846	$8,852,556
7	Net Expense (C)			997,263	670,819	599,856	915,537	1,264,469	1,160,949	1,063,637	1,136,392	1,002,939	664,810	504,759	524,189	10,207,630
8	Total System Recoverable Expenses (Lines 5 + 7)			1,359,072	1,023,255	945,516	954,502	1,593,095	1,476,236	1,366,690	1,429,333	1,282,103	934,803	768,319	782,090	13,915,215
	a. Recoverable costs allocated to Energy			1,359,072	1,023,255	945,516	954,502	1,593,095	1,476,236	1,366,690	1,429,333	1,282,103	934,803	768,319	782,090	13,915,215
	b. Recoverable costs allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor			0.96780	0.96220	0.96630	0.96650	0.96780	0.96960	0.96030	0.95790	0.95750	0.95620	0.95590	0.95990	
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)			1,315,310	984,576	913,652	922,526	1,541,797	1,431,358	1,312,624	1,369,158	1,227,614	893,859	734,436	750,729	13,397,640
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)			$ 1,315,310	$ 984,576	$ 913,652	$ 922,526	$ 1,541,797	$ 1,431,358	$ 1,312,624	$ 1,369,158	$ 1,227,614	$ 893,859	$ 734,436	$ 750,729	$ 13,397,640

Notes:
(A) Line 6 x 10.35% x 1/12. Based on ROE of 12.54%, weighted cost of equity component of capital structure of 6.36%, and statutory income tax rate of 38.575% (expansion factor of 1.6338). Based on proposal in PEF's rate case Dkt. 090079-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 Projected Period Amount
JANUARY 2010 - DECEMBER 2010
Return on Capital Investments, Depreciation and Taxes
For Project: CAIR - Intermediate (Project 7.1 - Anclote Low Nox Burners and SOFA)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	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)	10.35%		0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 2.57% x 1/12)	2.65%		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Other			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			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	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 (Intm)			0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	
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 10.35% x 1/12. Based on ROE of 12.54%, weighted cost of equity component of capital structure of 6.36%, and statutory income tax rate of 38.575% (expansion factor of 1.6336). Based on proposal in PEF's rate case Dkt. 090079-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on proposal in PEF's rate case Dkt. 090079-EI.
(D) Line 2 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. ___ (TGF-3)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
Return on Capital Investments, Depreciation and Taxes
For Project: CAIR - Peaking (Project 7.2 - CT Emission Monitoring Systems)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	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		$1,934,400	$1,934,400	$1,934,400	$1,934,400	$1,934,400	$1,934,400	$1,934,400	$1,934,400	$1,934,400	$1,934,400	$1,934,400	$1,934,400	$1,934,400	
3	Less: Accumulated Depreciation		(91,024)	(96,599)	(102,174)	(107,749)	(113,324)	(118,899)	(124,474)	(130,049)	(135,624)	(141,199)	(146,774)	(152,349)	(157,924)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$1,843,377	1,837,802	1,832,227	1,826,652	1,821,077	1,815,502	1,809,927	1,804,352	1,798,777	1,793,202	1,787,627	1,782,052	1,776,477	
6	Average Net Investment			1,840,590	1,835,015	1,829,440	1,823,865	1,818,290	1,812,715	1,807,140	1,801,565	1,795,990	1,790,415	1,784,840	1,779,265	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	10.35%		15,870	15,820	15,772	15,724	15,676	15,628	15,581	15,533	15,485	15,436	15,388	15,341	187,254
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		4,376	4,363	4,350	4,336	4,321	4,311	4,298	4,282	4,270	4,257	4,243	4,230	51,637
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			5,575	5,575	5,575	5,575	5,575	5,575	5,575	5,575	5,575	5,575	5,575	5,575	66,900
	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)			1,388	1,388	1,388	1,388	1,388	1,388	1,388	1,388	1,388	1,388	1,388	1,388	16,656
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			27,209	27,146	27,085	27,023	26,960	26,902	26,842	26,778	26,718	26,656	26,594	26,534	322,447
	a. Recoverable Costs Allocated to Energy			-	-	-	-	-	-	-	-	-	-	-	-	-
	b. Recoverable Costs Allocated to Demand			27,209	27,146	27,085	27,023	26,960	26,902	26,842	26,778	26,718	26,656	26,594	26,534	322,447
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Peaking)			0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	0.91716	
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)			24,955	24,897	24,841	24,784	24,727	24,673	24,618	24,560	24,505	24,448	24,391	24,336	295,735
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$24,955	$24,897	$24,841	$24,784	$24,727	$24,673	$24,618	$24,560	$24,505	$24,448	$24,391	$24,336	$295,735

Notes:
(A) N/A
(B) Line 6 x 10.35% x 1/12. Based on ROE of 12.54%, weighted cost of equity component of capital structure of 6.35%, and statutory income tax rate of 38.575% (expansion factor of 1.6338). Based on proposal in PEF's rate case Dkt. 090079-EI.
(C) Depreciation calculated in CAIR CTs section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on proposal in PEF's rate case Dkt. 090079-EI.
(D) Property tax calculated in CAIR CTs section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
Return on Capital Investments, Depreciation and Taxes
For Project: CAIR - Crystal River - Base (Project 7.3 - Continuous Mercury Monitoring Systems)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	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	
4	CWIP - Non-Interest Bearing		289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	
5	Net Investment (Lines 2 + 3 + 4)		$289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	
6	Average Net Investment			289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	10.35%		2,493	2,493	2,493	2,493	2,493	2,493	2,493	2,493	2,493	2,493	2,493	2,493	$29,916
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		687	687	687	687	687	687	687	687	687	687	687	687	8,244
	c. Other			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			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)			3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	38,160
	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			3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	3,180	38,160
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)			0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	
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)			2,915	2,915	2,915	2,915	2,915	2,915	2,915	2,915	2,915	2,915	2,915	2,915	34,981
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$2,915	$2,915	$2,915	$2,915	$2,915	$2,915	$2,915	$2,915	$2,915	$2,915	$2,915	$2,915	$34,981

Notes:
(A) N/A
(B) Line 6 x 10.35% x 1/12. Based on ROE of 12.54%, weighted cost of equity component of capital structure of 6.36%, and statutory income tax rate of 38.575% (expansion factor of 1.6338). Based on proposal in PEF's rate case Dkt. 090079-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on proposal in PEF's rate case Dkt. 090079-EI.
(D) Line 2 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. ___ (TGF-3)

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
Return on Capital Investments, Depreciation and Taxes
For Project: CAIR - Base - AFUDC (Project 7.4 - Crystal River FGD and SCR)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	End of Period Total
1	Investments															
	a. Expenditures/Additions			11,791,501	13,154,705	11,180,371	5,202,135	3,175,787	$3,433,939	$3,931,322	$889,781	$406,743	$387,177	$386,781	$386,665	$58,126,906
	b. Clearings to Plant			1,560,000	3,288,200	2,609,985	1,120,000	249,120,680	3,433,939	3,931,322	889,781	406,743	387,177	386,781	386,665	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)	7.667%		1,517,093	1,552,104	1,614,428	1,703,016	893,364	0	0	0	0	0	0	0	7,280,005
2	Plant-In-Service/Depreciation Base		$979,476,167	981,036,167	984,324,367	986,934,372	988,054,372	1,237,175,052	1,240,608,991	1,244,540,313	1,245,230,094	1,245,636,836	1,246,024,013	1,246,410,794	1,246,797,459	
3	Less: Accumulated Depreciation		($4,408,719)	(8,598,430)	(12,802,308)	(17,017,431)	(21,237,380)	(25,997,348)	(31,305,386)	(36,630,362)	(41,958,309)	(47,288,008)	(52,619,375)	(57,952,409)	(63,287,109)	
4	CWIP - AFUDC-Interest Bearing		201,914,382	213,862,958	225,081,585	235,266,379	245,051,530	0	0	0	0	0	0	0	0	65,406,911
5	Net Investment (Lines 2 + 3 + 4)		$1,176,981,830	1,186,100,712	1,196,603,644	1,205,183,319	1,211,868,521	1,211,177,704	1,209,303,605	1,207,909,951	1,203,271,785	1,198,348,829	1,193,404,638	1,188,458,386	1,183,510,350	
6	Average Net Investment			1,181,541,271	1,191,352,178	1,200,893,481	1,208,525,920	1,211,523,113	1,210,240,655	1,208,606,778	1,205,590,868	1,200,810,307	1,195,876,734	1,190,931,512	1,185,984,368	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	10.35%		8,395,370	8,380,068	8,369,221	8,348,938	9,386,973	10,434,292	10,420,205	10,394,203	10,352,988	10,310,460	10,267,616	10,225,162	115,287,704
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		2,315,007	2,310,882	2,307,887	2,302,292	2,589,092	2,877,347	2,873,463	2,866,291	2,854,927	2,843,197	2,831,439	2,819,677	31,791,591
	c. Other (C)			114,545	0	0	0	0	0	0	0	0	0	0	0	114,545
8	Investment Expenses															
	a. Depreciation (D)			4,189,711	4,203,878	4,215,123	4,219,949	4,759,968	5,308,038	5,324,976	5,327,947	5,329,699	5,331,367	5,333,034	5,334,700	58,878,390
	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 (E)			856,772	859,644	861,923	862,901	1,080,467	1,083,466	1,086,899	1,087,501	1,087,857	1,088,195	1,088,532	1,088,870	12,133,027
	e. Other (F)			83,193	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			15,934,688	15,754,492	15,754,154	15,734,080	17,818,501	19,703,143	19,705,543	19,675,942	19,625,469	19,573,209	19,520,821	19,468,409	218,268,451
	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			15,934,688	15,754,492	15,754,154	15,734,080	17,818,501	19,703,143	19,705,543	19,675,942	19,625,469	19,573,209	19,520,821	19,468,409	218,268,451
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)			0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	
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			14,607,169	14,441,985	14,441,675	14,423,274	16,334,042	18,061,674	18,063,874	18,036,739	17,990,471	17,942,565	17,894,541	17,846,496	200,084,506
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$14,607,169	$14,441,985	$14,441,675	$14,423,274	$16,334,042	$18,061,674	$18,063,874	$18,036,739	$17,990,471	$17,942,565	$17,894,541	$17,846,496	$200,084,506

Notes:
(A) AFUDC calculation based on proposal in PEF's rate case Dkt. 090079-EI.
(B) Return on equity and debt calculated only on assets placed in service which appear in CAIR Crystal River AFUDC section of Capital Program Detail file. Calculated on that schedule as Line 6 x rate x 1/12. Rate based on ROE of 12.54%, weighted cost of equity component of capital structure of 6.36%, and statutory income tax rate of 38.575% (expansion factor of 1.6338). Based on proposal in PEF's rate case Dkt. 090079-EI.
(C) T/U amount for the equity and debt components of the average net investment that were inadvertantly excluded in the 2009 Est/Actual filing.
(D) Depreciation calculated only on assets placed in-service which appear in CAIR Crystal River AFUDC section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Rate based on proposal in PEF's rate case Dkt. 090079-EI.
(E) Property taxes calculated only on assets placed in-service which appear in CAIR Crystal River AFUDC section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.
(F) T/U amount for depreciation and property tax expenses that were inadvertantly excluded in the 2009 Est/Actual filing.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
JANUARY 2010 - DECEMBER 2010

Schedule of Amortization and Return
For Project: CAIR - Energy - AFUDC (Project 7.4 - Reagents and By-products)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan - 10	Actual Feb - 10	Actual Mar - 10	Actual Apr - 10	Actual May - 10	Actual Jun - 10	Estimated Jul - 10	Estimated Aug - 10	Estimated Sep - 10	Estimated Oct - 10	Estimated Nov - 10	Estimated Dec - 10	End of Period Total
1	Working Capital Dr (Cr)															
	a. 1544001 Ammonia Inventory		$158,148	$164,105	$164,105	$164,105	$164,105	$164,105	$164,105	$164,105	$164,105	$164,105	$164,105	$164,105	$164,105	$164,105
	b. 1544004 Limestone Inventory		570,000	589,600	589,600	589,600	589,600	589,600	589,600	589,600	589,600	589,600	589,600	589,600	589,600	589,600
2	Total Working Capital		$728,148	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705
3	Average Net Investment			740,926	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705	753,705	
4	Return on Average Net Working Capital Balance															
	a. Equity Component Grossed Up For Taxes (A)	10.35%		6,388	6,498	6,498	6,498	6,498	6,498	6,498	6,498	6,498	6,498	6,498	6,498	$77,868
	b. Debt Component (Line 3 x 2.04% x 1/12)	2.85%		1,762	1,792	1,792	1,792	1,792	1,792	1,792	1,792	1,792	1,792	1,792	1,792	21,473
5	Total Return Component (B)			8,150	8,290	8,290	8,290	8,290	8,290	8,290	8,290	8,290	8,290	8,290	8,290	99,341
6	Expense Dr (Cr)															
	a. 5020011 Ammonia expense			253,398	218,073	257,348	236,362	202,109	530,288	514,636	567,914	535,720	535,485	436,209	565,378	4,852,920
	c. 5020012 Limestone Expense			58,148	50,765	124,613	114,176	74,193	195,891	190,429	311,904	304,004	302,984	238,228	327,001	2,292,336
	d. 5020003 Gypsum Disposal/Sale			380,324	359,321	569,398	539,709	425,968	772,168	756,830	1,102,194	1,079,720	1,076,818	892,608	1,145,142	9,100,000
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
7	Net Expense (C)			691,870	628,160	951,359	890,247	702,271	1,498,347	1,461,895	1,982,012	1,919,443	1,915,287	1,567,046	2,037,521	16,245,257
8	Total System Recoverable Expenses (Lines 5 + 7)			700,019	636,450	959,649	898,537	710,561	1,506,637	1,469,986	1,990,302	1,927,733	1,923,577	1,575,336	2,045,811	16,344,598
	a. Recoverable costs allocated to Energy			700,019	636,450	959,649	898,537	710,561	1,506,637	1,469,986	1,990,302	1,927,733	1,923,577	1,575,336	2,045,811	16,344,598
	b. Recoverable costs allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor			0.96780	0.96220	0.96630	0.96650	0.96780	0.96960	0.96030	0.95790	0.95750	0.95620	0.95590	0.95990	
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)			677,479	612,392	927,309	868,436	687,681	1,460,835	1,411,627	1,906,510	1,845,804	1,839,324	1,505,864	1,963,774	15,707,035
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)			$ 677,479	$ 612,392	$ 927,309	$ 868,436	$ 687,681	$ 1,460,835	$ 1,411,627	$ 1,906,510	$ 1,845,804	$ 1,839,324	$ 1,505,864	$ 1,963,774	$ 15,707,035

Notes:
(A) Line 3 x 10.35% x 1/12. Based on ROE of 12.54%, weighted cost of equity component of capital structure of 6.36%, and statutory income tax rate of 38.575% (expansion factor of 1.6338). Based on proposal in PEF's rate case Dkt. 090079-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. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. __ (TGF-3)
Page 14 of 39

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
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 - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	End of Period Total
1	Investments														
	a. Expenditures/Additions		1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	1,667	$20,000
	b. Clearings to Plant		0	0	5,000	0	0	5,000	0	0	5,000	0	0	5,000	
	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	$30,146	30,146	30,146	35,146	35,146	35,146	40,146	40,146	40,146	45,146	45,146	45,146	50,146	
3	Less: Accumulated Depreciation	(852)	(960)	(1,068)	(1,185)	(1,311)	(1,437)	(1,572)	(1,716)	(1,860)	(2,013)	(2,174)	(2,335)	(2,505)	
4	CWIP - Non-Interest Bearing	-	1,667	3,333	(0)	1,667	3,333	(0)	1,667	3,333	(0)	1,667	3,333	(0)	
5	Net Investment (Lines 2 + 3 + 4)	$29,294	30,853	32,411	33,961	35,502	37,042	38,574	40,097	41,619	43,133	44,639	46,144	47,641	
6	Average Net Investment		30,073	31,632	33,186	34,731	36,272	37,808	39,335	40,858	42,376	43,886	45,391	46,893	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 10.35%		259	273	286	299	313	326	339	352	365	378	391	404	$3,985
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.85%		71	75	79	83	86	90	94	97	101	104	108	111	1,099
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation (C) 4.29%		108	108	117	126	126	135	144	144	153	161	161	170	1,653
	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) 0.009423		24	24	28	28	28	32	32	32	35	35	35	39	372
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		462	480	510	536	553	583	609	625	654	678	695	724	7,109
	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		462	480	510	536	553	583	609	625	654	678	695	724	7,109
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)		0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	0.99634	
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)		460	478	508	534	551	581	607	623	652	676	692	721	7,083
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$460	$478	$508	$534	$551	$581	$607	$623	$652	$676	$692	$721	$7,083

Notes:
(A) N/A
(B) Line 6 x 10.35% x 1/12. Based on ROE of 12.54%, weighted cost of equity component of capital structure of 6.38%, and statutory income tax rate of 38.575% (expansion factor of 1.6338). Based on proposal in PEF's rate case Dkt. 090079-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on proposal in PEF's rate case Dkt. 090079-EI.
(D) Line 2 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
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 - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	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	(14,032)	(14,463)	(14,894)	(15,325)	(15,756)	(16,187)	(16,618)	(17,049)	(17,480)	(17,911)	(18,342)	(18,773)	(19,204)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	$154,909	154,478	154,047	153,616	153,185	152,754	152,323	151,892	151,461	151,030	150,599	150,168	149,737	
6	Average Net Investment		154,694	154,263	153,832	153,401	152,970	152,539	152,108	151,677	151,246	150,815	150,384	149,953	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B) 10.35%		1,334	1,330	1,326	1,323	1,319	1,315	1,311	1,308	1,304	1,300	1,297	1,293	$15,760
	b. Debt Component (Line 6 x 2.04% x 1/12) 2.85%		368	367	366	365	364	363	362	361	360	359	358	357	4,350
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation (C) 3.06%		431	431	431	431	431	431	431	431	431	431	431	431	5,172
	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) 0.010480		148	148	148	148	148	148	148	148	148	148	148	148	1,776
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,281	2,276	2,271	2,267	2,262	2,257	2,252	2,248	2,243	2,238	2,234	2,229	27,058
	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		2,281	2,276	2,271	2,267	2,262	2,257	2,252	2,248	2,243	2,238	2,234	2,229	27,058
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)		0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	
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)		2,091	2,086	2,082	2,078	2,074	2,069	2,064	2,061	2,056	2,052	2,048	2,043	24,804
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$2,091	$2,086	$2,082	$2,078	$2,074	$2,069	$2,064	$2,061	$2,056	$2,052	$2,048	$2,043	$24,804

Notes:
(A) N/A
(B) Line 6 x 10.35% x 1/12. Based on ROE of 12.54%, weighted cost of equity component of capital structure of 6.36%, and statutory income tax rate of 38.575% (expansion factor of 1.6338). Based on proposal in PEF's rate case Dkt. 090079-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on proposal in PEF's rate case Dkt. 090079-EI.
(D) Line 2 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Progress Energy Florida
Witness: T.G. Foster
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
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 - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	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		$76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	
	3 Less: Accumulated Depreciation		(7,169)	(7,367)	(7,565)	(7,763)	(7,961)	(8,159)	(8,357)	(8,555)	(8,753)	(8,951)	(9,149)	(9,347)	(9,545)	
	4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
	5 Net Investment (Lines 2 + 3 + 4)		$68,837	68,639	68,441	68,243	68,045	67,847	67,649	67,451	67,253	67,055	66,857	66,659	66,461	
	6 Average Net Investment			68,738	68,540	68,342	68,144	67,946	67,748	67,550	67,352	67,154	66,956	66,758	66,560	
	7 Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	10.35%		593	591	589	588	586	584	582	581	579	577	576	574	$7,000
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		163	163	162	162	162	161	161	160	160	159	159	158	1,930
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
	8 Investment Expenses															
	a. Depreciation (C)	3.12%		198	198	198	198	198	198	198	198	198	198	198	198	2,376
	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)	0.009130		58	58	58	58	58	58	58	58	58	58	58	58	696
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
	9 Total System Recoverable Expenses (Lines 7 + 8)			1,012	1,010	1,007	1,006	1,004	1,001	999	997	995	992	991	988	12,002
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,012	1,010	1,007	1,006	1,004	1,001	999	997	995	992	991	988	12,002
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)			0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	0.59352	
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)			601	599	598	597	596	594	593	592	591	589	588	586	7,123
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$601	$599	$598	$597	$596	$594	$593	$592	$591	$589	$588	$586	$7,123

Notes:
(A) N/A
(B) Line 6 x 10.35% x 1/12. Based on ROE of 12.54%, weighted cost of equity component of capital structure of 6.36%, and statutory income tax rate of 38.575% (expansion factor of 1.6338). Based on proposal in PEF's rate case Dkt. 090079-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on proposal in PEF's rate case Dkt. 090079-EI.
(D) Line 2 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
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 - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	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		$665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	
3	Less: Accumulated Depreciation		(457,179)	(468,265)	(479,351)	(490,437)	(501,523)	(512,609)	(523,695)	(534,781)	(545,867)	(556,953)	(568,039)	(579,125)	(590,211)	
4	CWIP - Non-Interest Bearing		-	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$207,962	196,876	185,790	174,704	163,618	152,532	141,446	130,360	119,274	108,188	97,102	86,016	74,930	
6	Average Net Investment			202,419	191,333	180,247	169,161	158,075	146,989	135,903	124,817	113,731	102,645	91,559	80,473	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	10.35%		1,745	1,650	1,554	1,458	1,363	1,267	1,172	1,076	981	885	789	694	$14,634
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		481	455	429	402	376	349	323	297	270	244	218	191	4,035
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C) 20.00%			11,086	11,086	11,086	11,086	11,086	11,086	11,086	11,086	11,086	11,086	11,086	11,086	133,032
	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) 0.010480			581	581	581	581	581	581	581	581	581	581	581	581	6,972
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			13,893	13,772	13,650	13,527	13,406	13,283	13,162	13,040	12,918	12,796	12,674	12,552	158,673
	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			13,893	13,772	13,650	13,527	13,406	13,283	13,162	13,040	12,918	12,796	12,674	12,552	158,673
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)			0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	
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)			12,736	12,625	12,513	12,400	12,289	12,176	12,065	11,954	11,842	11,730	11,618	11,506	145,454
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$12,736	$12,625	$12,513	$12,400	$12,289	$12,176	$12,065	$11,954	$11,842	$11,730	$11,618	$11,506	$145,454

Notes:
(A) N/A
(B) Line 6 x 10.35% x 1/12. Based on ROE of 12.54%, weighted cost of equity component of capital structure of 6.36%, and statutory income tax rate of 38.575% (expansion factor of 1.6338). Based on proposal in PEF's rate case Dkt. 090079-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 5 year life of project, as stated in Dkt. 050162-EI.
(D) Line 2 x rate x 1/12. Based on 2008 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2010 - DECEMBER 2010
Return on Capital Investments, Depreciation and Taxes
For Project: Crystal River Thermal Discharge Compliance Project- AFUDC - Base (Project 11.1)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan - 10	Projected Feb - 10	Projected Mar - 10	Projected Apr - 10	Projected May - 10	Projected Jun - 10	Projected Jul - 10	Projected Aug - 10	Projected Sep - 10	Projected Oct - 10	Projected Nov - 10	Projected Dec - 10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$1,868,161	$2,602,065	$1,862,773	$2,273,032	$2,568,046	$3,100,537	$4,668,022	$3,304,359	$5,473,948	$3,443,422	$1,740,138	$1,703,100	$34,607,603
	b. Clearings to Plant			0	0	0	0	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)	7.667%		$ 81,938	$ 98,367	$ 114,692	$ 130,358	$ 146,625	$ 169,744	$ 198,487	$ 226,158	$ 260,893	$ 294,355	$ 314,817	$ 329,256	$2,369,796
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		$9,537,888	11,406,069	14,008,134	15,870,907	18,143,939	20,731,984	23,832,521	28,500,543	31,804,902	37,278,850	40,722,272	42,462,410	44,165,511	
5	Net Investment (Lines 2 + 3 + 4)		$0	11,406,069	14,008,134	15,870,907	18,143,939	20,731,984	23,832,521	28,500,543	31,804,902	37,278,850	40,722,272	42,462,410	44,165,511	
6	Average Net Investment			5,703,034	12,707,101	14,939,520	17,007,423	19,437,961	22,282,252	26,166,532	30,152,723	34,541,876	39,000,561	41,592,341	43,313,961	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes (B)	10.35%		0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 2.04% x 1/12)	2.85%		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Other			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)			0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	0.91669	
12	Retail Energy-Related Recoverable Costs (C)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (D)			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) AFUDC calculation based on proposal in PEF's rate case Dkt. 090079-EI.
(B) Line 6 x 10.35% x 1/12. Based on ROE of 12.54%, weighted cost of equity component of capital structure of 6.36%, and statutory income tax rate of 38.575% (expansion factor of 1.6338). Based on proposal in PEF's rate case Dkt. 090079-EI.
(C) Line 9a x Line 10
(D) Line 9b x Line 11

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Progress Energy Florida
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2010 - DECEMBER 2010
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 41 substations during 2008. PEF is currently on target to meet the schedule for substation remediations agreed to with the FDEP for 2009.

Project Fiscal Expenditures:
January 1, 2009 to December 31, 2009: Project expenditures are estimated to be $2,728,163 lower than originally projected. This variance is primarily due to scheduling conflicts that resulted in multiple sites being rescheduled from the first half of 2009 to the fourth quarter of 2009 and into 2010, multiple sites containing less contamination than originally projected, and recent scope changes to the remediation taking place at the West Lake Wales substation site.

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 2010 through December 2010 are expected to be $2,075,411.

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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 has completed all TRIP inspections and has finalized its remaining targets. PEF is expecting to complete remediations on 875 distribution padmount transformer sites in 2009. All remediations have been conducted in accordance with the FDEP approved Environmental Remediation Strategy.

Project Fiscal Expenditures:
January 1, 2009 to December 31, 2009: Project expenditures are estimated to be $70,481 higher than originally projected.

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 2010 through December 2010 are expected to be approximately $8.9 million. Progress Energy is expecting to complete remediations on approximately 750 sites.

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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 2009 Regulatory Compliance Partners completed a regulatory gap analysis of the PIM program using the PHMSA Protocols, the Integrity Management Program Plan Revision 6 was completed and BAP personnel have participated in the design process and construction coordination for FDOT Projects at US 19 and Haines Bayshore Road, and 9th Street and Gandy Boulevard.

Project Fiscal Expenditures:
January 1, 2009 to December 31, 2009: O&M project expenditures are estimated to be in line with the originally projected expenses.

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 2009, and into the future.

Project Projections:
Estimated project O&M expenditures for the period January 2010 through December 2010 are expected to be $1,218,000.

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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:
The following tanks were completed and placed into service during 2009: DeBary 1, Turner 7, Turner 8 and Higgins 1. Work on Bartow 6 will commence in September 2009. Turner P-1 and P-2 piping work is anticipated to begin in September 2009 and is expected to be completed by year-end.

Project Fiscal Expenditures:
January 1, 2009 to December 31, 2009: There are no projected O&M project expenditures for this project in 2009.

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 2010 through December 2010 are expected to be approximately $638,000. The costs are associated with the tank upgrade work at Bartow.

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Project Title: SO_2 and NOX Emissions
Project No. 5

Project Description:
In accordance with Title IV of the Clean Air Act, CFR 40 Part 73 and Part 76, and Florida Statute Regulation 62-214, PEF manages the company's SO2 and NOX emissions allowance inventory for the purpose of offsetting sulfur dioxide and nitrogen oxides emissions in compliance with the Federal Acid Rain Program.

Project Accomplishments:
For purposes of compliance with an affected unit's sulfur dioxide and nitrogen oxides 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 of SO2 and NOX emissions allowances as well as auctions and transfers of SO2 emissions allowances.

Project Fiscal Expenditures:
January 1, 2009 to December 31, 2009: Project expenditures are estimated to be $19,338,701 lower than originally projected. This variance is primarily driven by actual emissions being lower than forecasted emissions due to lower power demand and fuel switching from coal-fired and oil-fired generation to gas-fired generation when economically and operationally feasible. Also, the weighted average cost – the per allowance cost at which emissions are expensed – is lower than the original projection.

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:
For the period January 2010 through December 2010 Estimated SO2 expenditures are expected to be $1,568,253 and NOX project expenditures for the period and $8,852,556, respectively. PEF also expects approximately $213,180 in amortization expense from SO2 auction proceeds in 2010.

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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 and approved by the FDEP.

Project Fiscal Expenditures:
January 2009 - December 2009: Due to the vacatur, the estimated project O&M expenditures for the period January 2009 through December 2009 are projected to be $0.

Project Progress Summary:
The original baseline biological studies have been completed. Work has been suspended pending completion of additional rulemaking.

Project Projections:
Due to the vacatur, the estimated project O&M expenditures for the period January 2010 through December 2010 are projected to be $0.

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Project Title: **Integrated Clean Air Compliance Plan (CAIR)**
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.

Project Accomplishments:
Progress Energy achieved several significant project milestones in 2009. In June 2009, we placed the Crystal River Unit 5 low NOx burners ("LNB") and selective catalytic ("SCR") system into service and in July 2009 we placed the urea to ammonia hydrolyser into service. Additionally, in December 2009, we expect to place the Unit 5 Flue Gas Desulfurization ("FGD" or "scrubber") system and chimney into service.

Project Fiscal Expenditures:
January 2009 - December 2009: PEF's expenditures for the Crystal River Projects in 2009 will be approximately $215.8 million, which is in line with the original projection expenditures of $215.9 million.

Project Progress Summary:
PEF will continue to regularly track project expenditures against the detailed project scopes to ensure that PEF receives what it contracted for and that any scope changes are properly evaluated and documented. We also will continue to conduct regularly scheduled meetings with the primary contractors and senior management to maintain supervision of the project, to ensure that management remains fully informed, and to ensure that management expectations are communicated to the outside vendors and the project team.

Project Projections:
Estimated project expenditures for the period January 2010 through December 2010 are expected to be approximately $58.1 million relating to the SCR and FGD systems at both Crystal River Units 4 and 5.

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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 reissued Industrial Wastewater Permit. Discussions are continuing with FDEP relative to an acceptable strategic plan.

Project Fiscal Expenditures:
January 2009 - December 2009: O&M costs are expected to be $77,669 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:
Progress Energy continues to work with the Florida Department of Environmental Protection to comply with the terms of the renewed industrial wastewater permit for the Crystal River Energy Complex (January 9, 2007) and the modified Conditions of Certification (November 29, 2007; and June 5, 2009). Given this level of uncertainly regarding this program, PEF is not projecting any costs specific to the Arsenic program in 2010.

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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 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, monitoring them for effectiveness, and making modifications to the retrofitted lights where applicable. Project studies are ongoing with University of Florida and are expected to continue through 2010.

Project Fiscal Expenditures:
January 1, 2009 to December 31, 2009: Project revenue requirements are estimated to be slightly lower than the original 2009 projection of $7202.

Project Progress Summary:
PEF is on schedule with the activities identified for this program.

Project Projections:
Estimated project expenditures for the period January 2010 through December 2010 are expected to be $1,800 in O&M costs and $20,000 in capital expenditures to ensure ongoing compliance with sea turtle ordinances.

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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 2009.

Project Projections:
No project capital expenditures are anticipated for the period January 2010 through December 2010.

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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 Crystal 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 $3.3 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 $3.3 million for the period January 2010 thru December 2010.

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Project Title: **Crystal River Thermal Discharge Compliance Project**
Project No. 11.1

Project Description:
This project will evaluate and implement the best long term solution to maintain compliance with the thermal discharge limit in FDEP industrial wastewater permit for Crystal River 1 & 2 that is currently being addressed in the short term by the Modular Cooling Towers approved in Docket # 060162- EI for ECRC recovery.

Project Accomplishments:
The Study phase of the project is complete. The recommendation is to replace the modular cooling towers in coordination with the cooling solution for the CR3 EPU discharge canal cooling solution. The new cooling tower associated with the CR3 EPU will be sized to mitigate both the increased temperatures from the EPU as well as serve to replace the modular cooling towers.

Project Fiscal Expenditures:
January 1, 2009 to December 31, 2009: PEF is projecting capital expenditures to be $2,440,619 lower for this project in 2009 than originally forecast. This variance is mainly attributable to the refinement of project costs reflecting design changes due to anticipated scope reductions and associated procurement requirements.

Project Progress Summary:
The design contract for the CR3 EPU cooling tower has been awarded and a cooling tower supplier has been selected.

Project Projections:
Estimated project expenditures are expected to be approximately $34.6 million for the period January 2010 thru December 2010.

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Project Title: **Greenhouse Gas Inventory and Reporting**
Project No. 12

Project Description:
The Greenhouse Gas (GHG) Inventory and Reporting Program was created in response to Chapter 2008-277, Florida Laws, which established the Florida Climate Protection Act, to be codified at section 403.44, Florida Statutes. Among other things, this legislation authorizes FDEP to establish a cap and trade program to GHG emissions from electric utilities. Utilities subject to the program, including PEF, will be required to use The Climate Registry for purposes of GHG emission registration and reporting.

Project Accomplishments:
During 2009, Progress Energy joined The Climate Registry and has submitted the 2008 GHG inventory.

Project Fiscal Expenditures:
January 1, 2009 to December 31, 2009: O&M project expenditures are estimated to be $42,680 less than originally projected. This variance is the result of preparing the inventory report with internal resources rather than external consultants during the first two quarters of the year. A third party consultant will be hired for verification of the report, as required by the Climate Registry, and those are the expenses now projected for 2009.

Project Progress Summary:
The 2008 GHG inventory is currently verification ready and a kick-off meeting for verification was held in July 2009.

Project Projections:
Estimated project expenditures are expected to be approximately $22,500 for the period January 2010 thru December 2010.

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Project Title: **Mercury Total Daily Maximum Loads Monitoring**
Project No. 13

Project Description:
Section 303(d) of the federal Clean Water Act requires each state to identify state waters not meeting water quality standards and establish a TMDL for the pollutant or pollutants causing the failure to meet standards. Under a 1999 federal consent decree, TMDLs for over 100 Florida water bodies listed as impaired for mercury must be established by September 12, 2012. DEP has initiated a research program to provide the necessary information for setting the appropriate TMDLs for mercury. Among other things, the study will assess the relative contributions of mercury-emitting sources, such as coal-fired power plants, to mercury levels in surface waters.

Project Accomplishments:
Atmospheric & Environmental Research, Inc (AER) has completed the literature review on mercury deposition in Florida, this document has been sent to the Division of Air Resource Management and the TMDL team for review. In addition, the Mercury Task Force has met with both the Division of Air Resource Management in the TMDL team to discuss the review. AER has initiated the Florida mercury deposition modeling for the Division of Air Resource Management, it is anticipating this work will be done by the end of 2009.

Project Fiscal Expenditures:
January 1, 2009 to December 31, 2009: PEF expects that total O&M project expenditures for the year will be approximately $92,164.

Project Progress Summary:
The Florida Electric Coordinating Group (FCG) Mercury task force continues to meet with the state as the changes in the program evolve. In 2009 PEF contracted with private contractor to develop a conceptual model, and continue to that work into 2010.

Project Projections:
Estimated project expenditures are expected to be approximately $36,077 for the period January 2010 thru December 2010.

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Calculation of the Energy & Demand Allocation % by Rate Class
JANUARY 2010 - DECEMBER 2010

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)/(8760hrs x (1))	(4) NCP Class Max Load Factor	(5) Delivery Efficiency Factor	(6) Sales at Source (Generation) (mWh) (2)/(5)	(7) Avg 12 CP at Source (MW) (3)/(5)	7(a) Sales at Source (Distrib Svc Only) (mWh)	(8) Class Max MW at Source Level (Distrib Svc) (7a)/(8760hrs/(4))	(9) mWh Sales at Source Energy Allocator (%)	(10) 12CP Demand Transmission Allocator (%)	(11) 12CP & 1/13 AD Demand Allocator (%)	(12) NCP Distribution Allocator (%)
Residential													
RS-1, RST-1, RSL-1, RSL-2, RSS-1													
Secondary	0.494	18,303,702	4,229.68	0.361	0.9364356	19,546,141	4,516.79	19,546,141	6,180.9	50.554%	62.735%	61.798%	63.795%
General Service Non-Demand													
GS-1, GST-1													
Secondary	0.695	1,120,052	183.97	0.423	0.9364356	1,196,080	196.46	1,196,080	322.8	3.094%	2.729%	2.757%	3.332%
Primary	0.695	7,294	1.20	0.423	0.9682000	7,534	1.24	7,534	2.0	0.019%	0.017%	0.017%	0.021%
Transmission	0.695	3,574	0.59	0.423	0.9782000	3,654	0.60	0	0.0	0.009%	0.008%	0.008%	0.000%
										3.122%	2.754%	2.783%	3.353%
General Service													
GS-2 Secondary	1.000	86,214	9.84	1.000	0.9364356	92,066	10.51	92,066	10.5	0.238%	0.146%	0.153%	0.106%
General Service Demand													
GSD-1, GSDT-1													
Secondary	0.785	11,831,271	1,720.51	0.612	0.9364356	12,634,367	1,837.30	12,634,367	2,356.7	32.677%	25.519%	26.069%	24.324%
Primary	0.785	2,253,073	327.64	0.612	0.9682000	2,327,074	338.40	2,327,074	434.1	6.019%	4.700%	4.802%	4.480%
Transmission	0.785	0	0.00	0.612	0.9782000	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
SS-1 Primary	1.546	0	0.00	0.207	0.9682000	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Transm Del/ Transm Mtr	1.546	16,205	1.20	0.207	0.9782000	16,566	1.22	0	0.0	0.043%	0.017%	0.019%	0.000%
Transm Del/ Primary Mtr	1.546	4,338	0.32	0.207	0.9682000	4,480	0.33	0	0.0	0.012%	0.005%	0.005%	0.000%
										38.750%	30.240%	30.895%	28.804%
Curtailable													
CS-1, CST-1, CS-2, CST-2, SS-3													
Secondary	0.935	0	0.00	0.592	0.9364356	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Primary	0.935	168,726	20.60	0.592	0.9682000	174,268	21.28	174,268	33.6	0.451%	0.296%	0.307%	0.347%
SS-3 Primary	0.451	9,545	2.42	0.047	0.9682000	9,859	2.50	9,859	23.9	0.025%	0.035%	0.034%	0.247%
										0.476%	0.330%	0.341%	0.594%
Interruptible													
IS-1, IST-1, IS-2, IST-2													
Secondary	0.983	98,446	11.43	0.768	0.9364356	105,128	12.21	105,128	15.6	0.272%	0.170%	0.177%	0.161%
Sec Del/Primary Mtr	0.983	4,366	0.51	0.768	0.9682000	4,509	0.52	4,509	0.7	0.012%	0.007%	0.008%	0.007%
Primary Del / Primary Mtr	0.983	1,396,962	162.23	0.768	0.9682000	1,442,844	167.56	1,442,844	214.5	3.732%	2.327%	2.435%	2.214%
Primary Del / Transm Mtr	0.983	16,975	1.97	0.768	0.9782000	17,353	2.02	17,353	2.6	0.045%	0.028%	0.029%	0.027%
Transm Del/ Transm Mtr	0.983	257,555	29.91	0.768	0.9782000	263,295	30.58	0	0.0	0.681%	0.425%	0.444%	0.000%
Transm Del/ Primary Mtr	0.983	275,801	32.03	0.768	0.9682000	284,860	33.08	0	0.0	0.737%	0.459%	0.481%	0.000%
SS-2 Primary	0.929	0	0.00	0.447	0.9682000	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Transm Del/ Transm Mtr	0.929	81,348	10.00	0.447	0.9782000	83,161	10.22	0	0.0	0.215%	0.142%	0.146%	0.000%
Transm Del/ Primary Mtr	0.929	67,633	8.31	0.447	0.9682000	69,854	8.58	0	0.0	0.181%	0.119%	0.124%	0.000%
										5.874%	3.677%	3.846%	2.408%
Lighting													
LS-1 (Secondary)	5.151	356,890	7.91	0.479	0.9364356	381,115	8.45	381,115	90.8	0.986%	0.117%	0.184%	0.937%
		36,359,970	6,762.26			38,664,208	7,199.84	37,938,339	9,688.6	100.000%	100.000%	100.000%	100.000%

Notes:
(1) Average 12CP load factor based on load research study filed July 31, 2009
(2) Projected kWh sales for the period January 2009 to December 2009
(3) Calculated: Column 2 / (8,760 hours x Column 1)
(4) NCP load factor based on load research study filed July 31, 2009
(5) Based on system average line loss analysis for 2008
(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
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % by Rate Class
JANUARY 2010 - DECEMBER 2010

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)/(8760hrs x (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 x (4))	(9) mWh Sales at Source Energy Allocator (%)	(10) 12CP Demand Transmission Allocator (%)	(11) 12CP & 50% AD Demand Allocator (%)	(12) NCP Distribution Allocator (%)
Residential													
RS-1, RST-1, RSL-1, RSL-2, RSS-1													
Secondary	0.494	18,303,702	4,229.68	0.381	0.9364356	19,546,141	4,516.79	19,546,141	6,180.9	50.554%	62.735%	56.644%	63.795%
General Service Non-Demand													
GS-1, GST-1													
Secondary	0.695	1,120,052	183.97	0.423	0.9364356	1,196,080	196.46	1,196,080	322.8	3.094%	2.729%	2.911%	3.332%
Primary	0.695	7,294	1.20	0.423	0.9682000	7,534	1.24	7,534	2.0	0.019%	0.017%	0.018%	0.021%
Transmission	0.695	3,574	0.59	0.423	0.9782000	3,654	0.60	0	0.0	0.009%	0.008%	0.009%	0.000%
										3.122%	2.754%	2.938%	3.353%
General Service													
GS-2 Secondary	1.000	86,214	9.84	1.000	0.9364356	92,066	10.51	92,066	10.5	0.238%	0.146%	0.192%	0.108%
General Service Demand													
GSD-1, GSDT-1													
Secondary	0.785	11,831,271	1,720.51	0.612	0.9364356	12,634,367	1,837.30	12,634,367	2,356.7	32.677%	25.519%	29.098%	24.324%
Primary	0.785	2,253,073	327.64	0.612	0.9682000	2,327,074	338.40	2,327,074	434.1	6.019%	4.700%	5.359%	4.480%
Transmission	0.785	0	0.00	0.612	0.9782000	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
SS-1 Primary	1.546	0	0.00	0.207	0.9682000	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Transm Del/ Transm Mtr	1.546	16,205	1.20	0.207	0.9782000	16,566	1.22	0	0.0	0.043%	0.017%	0.030%	0.000%
Transm Del/ Primary Mtr	1.546	4,338	0.32	0.207	0.9682000	4,480	0.33	0	0.0	0.012%	0.005%	0.008%	0.000%
										38.750%	30.240%	34.495%	28.804%
Curtailable													
CS-1, CST-1, CS-2, CST-2, SS-3													
Secondary	0.935	0	0.00	0.592	0.9364356	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Primary	0.935	168,726	20.60	0.592	0.9682000	174,268	21.28	174,268	33.6	0.451%	0.296%	0.373%	0.347%
SS-3 Primary	0.451	9,545	2.42	0.047	0.9682000	9,859	2.50	9,859	23.9	0.025%	0.035%	0.030%	0.247%
										0.476%	0.330%	0.403%	0.594%
Interruptible													
IS-1, IST-1, IS-2, IST-2													
Secondary	0.983	98,446	11.43	0.768	0.9364356	105,128	12.21	105,128	15.6	0.272%	0.170%	0.221%	0.161%
Sec Del/Primary Mtr	0.983	4,366	0.51	0.768	0.9682000	4,509	0.52	4,509	0.7	0.012%	0.007%	0.009%	0.007%
Primary Del / Primary Mtr	0.983	1,396,962	162.23	0.768	0.9682000	1,442,844	167.56	1,442,844	214.5	3.732%	2.327%	3.029%	2.214%
Primary Del / Transm Mtr	0.983	16,975	1.97	0.768	0.9782000	17,353	2.02	17,353	2.6	0.045%	0.028%	0.036%	0.027%
Transm Del/ Transm Mtr	0.983	257,555	29.91	0.768	0.9782000	263,295	30.58	0	0.0	0.681%	0.425%	0.553%	0.000%
Transm Del/ Primary Mtr	0.983	275,801	32.03	0.768	0.9682000	284,860	33.08	0	0.0	0.737%	0.459%	0.598%	0.000%
SS-2 Primary	0.929	0	0.00	0.447	0.9682000	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Transm Del/ Transm Mtr	0.929	81,348	10.00	0.447	0.9782000	83,161	10.22	0	0.0	0.215%	0.142%	0.179%	0.000%
Transm Del/ Primary Mtr	0.929	67,633	8.31	0.447	0.9682000	69,854	8.58	0	0.0	0.181%	0.119%	0.150%	0.000%
										5.874%	3.677%	4.776%	2.408%
Lighting													
LS-1 (Secondary)	5.151	356,890	7.91	0.479	0.9364356	381,115	8.45	381,115	90.8	0.986%	0.117%	0.552%	0.937%
		36,359,970	6,762.26			38,664,208	7,199.84	37,938,339	9,688.6	100.000%	100.000%	100.000%	100.000%

Notes:

(1) Average 12CP load factor based on load research study filed July 31, 2009
(2) Projected kWh sales for the period January 2009 to December 2009
(3) Calculated: Column 2 / (8,760 hours x Column 1)
(4) NCP load factor based on load research study filed July 31, 2009
(5) Based on system average line loss analysis for 2008
(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 50% + Column 10 x 50%
(12) Column 8/ Total Column 8

Form 42-6P

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % by Rate Class
JANUARY 2010 - DECEMBER 2010

Rate Class	(1) Average 12CP Load Factor at Meter (%)	(2) Sales at Meter (mWh)	(3) Avg 12 CP at Meter (MW) (2)/(8760hrs x (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 x (4))	(9) mWh Sales at Source Energy Allocator (%)	(10) 12CP Demand Transmission Allocator (%)	(11) 12CP & 25% AD Demand Allocator (%)	(12) NCP Distribution Allocator (%)
Residential													
RS-1, RST-1, RSL-1, RSL-2, RSS-1													
Secondary	0.494	18,303,702	4,229.68	0.361	0.9364356	19,546,141	4,516.79	19,546,141	6,180.9	50.554%	62.735%	59.689%	63.795%
General Service Non-Demand													
GS-1, GST-1													
Secondary	0.695	1,120,052	183.97	0.423	0.9364356	1,196,080	196.46	1,196,080	322.8	3.094%	2.729%	2.820%	3.332%
Primary	0.695	7,294	1.20	0.423	0.9682000	7,534	1.24	7,534	2.0	0.019%	0.017%	0.018%	0.021%
Transmission	0.695	3,574	0.59	0.423	0.9782000	3,654	0.60	0	0.0	0.009%	0.008%	0.009%	0.000%
										3.122%	2.754%	2.846%	3.353%
General Service													
GS-2 Secondary	1.000	86,214	9.84	1.000	0.9364356	92,066	10.51	92,066	10.5	0.238%	0.146%	0.169%	0.108%
General Service Demand													
GSD-1, GSDT-1													
Secondary	0.785	11,831,271	1,720.51	0.612	0.9364356	12,634,367	1,837.30	12,634,367	2,356.7	32.677%	25.519%	27.308%	24.324%
Primary	0.785	2,253,073	327.64	0.612	0.9682000	2,327,074	338.40	2,327,074	434.1	6.019%	4.700%	5.030%	4.480%
Transmission	0.785	0	0.00	0.612	0.9782000	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
SS-1 Primary	1.546	0	0.00	0.207	0.9682000	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Transm Del/ Transm Mtr	1.546	16,205	1.20	0.207	0.9782000	16,566	1.22	0	0.0	0.043%	0.017%	0.023%	0.000%
Transm Del/ Primary Mtr	1.546	4,338	0.32	0.207	0.9682000	4,480	0.33	0	0.0	0.012%	0.005%	0.006%	0.000%
										38.750%	30.240%	32.368%	28.804%
Curtailable													
CS-1, CST-1, CS-2, CST-2, SS-3													
Secondary	0.935	0	0.00	0.592	0.9364356	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Primary	0.935	168,726	20.60	0.592	0.9682000	174,268	21.28	174,268	33.6	0.451%	0.296%	0.334%	0.347%
SS-3 Primary	0.451	9,545	2.42	0.047	0.9682000	9,859	2.50	9,859	23.9	0.025%	0.035%	0.032%	0.247%
										0.476%	0.330%	0.367%	0.594%
Interruptible													
IS-1, IST-1, IS-2, IST-2													
Secondary	0.983	98,446	11.43	0.768	0.9364356	105,128	12.21	105,128	15.6	0.272%	0.170%	0.195%	0.181%
Sec Del/Primary Mtr	0.983	4,366	0.51	0.768	0.9682000	4,509	0.52	4,509	0.7	0.012%	0.007%	0.008%	0.007%
Primary Del / Primary Mtr	0.983	1,396,962	162.23	0.768	0.9682000	1,442,844	167.56	1,442,844	214.5	3.732%	2.327%	2.678%	2.214%
Primary Del / Transm Mtr	0.983	16,975	1.97	0.768	0.9782000	17,353	2.02	17,353	2.6	0.045%	0.028%	0.032%	0.027%
Transm Del/ Transm Mtr	0.983	257,565	29.91	0.768	0.9782000	263,295	30.58	0	0.0	0.681%	0.425%	0.489%	0.000%
Transm Del/ Primary Mtr	0.983	275,601	32.03	0.768	0.9682000	284,660	33.08	0	0.0	0.737%	0.459%	0.529%	0.000%
SS-2 Primary	0.929	0	0.00	0.447	0.9682000	0	0.00	0	0.0	0.000%	0.000%	0.000%	0.000%
Transm Del/ Transm Mtr	0.929	81,348	10.00	0.447	0.9782000	83,161	10.22	0	0.0	0.215%	0.142%	0.160%	0.000%
Transm Del/ Primary Mtr	0.929	67,633	8.31	0.447	0.9682000	69,854	8.58	0	0.0	0.181%	0.119%	0.135%	0.000%
										5.874%	3.677%	4.226%	2.408%
Lighting													
LS-1 (Secondary)	5.151	356,890	7.91	0.479	0.9364356	381,115	8.45	381,115	90.8	0.986%	0.117%	0.334%	0.937%
		36,359,970	6,762.26			38,664,208	7,199.84	37,938,339	9,888.6	100.000%	100.000%	100.000%	100.000%

Notes:

(1) Average 12CP load factor based on load research study filed July 31, 2009
(2) Projected kWh sales for the period January 2009 to December 2009
(3) Calculated: Column 2 / (8,760 hours x Column 1)
(4) NCP load factor based on load research study filed July 31, 2009
(5) Based on system average line loss analysis for 2008
(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 25% + Column 10 x 25%
(12) Column 8/ Total Column 8

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. __ (TGF-3)
Page 36 of 39

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of Environmental Cost Recovery Clause Rate Factors by Rate Class
JANUARY 2010 - DECEMBER 2010

Rate Class	(1) mWh Sales at Source Energy Allocator (%)	(2) 12CP Transmission Allocator (%)	(3) 12CP & 50% AD Demand Allocator (%)	(4) NCP Distribution Allocator (%)	(5) Energy-Related Costs ($)	(6) Transmission Demand Costs ($)	(7) Distribution Demand Costs ($)	(8) Production Demand Costs ($)	(9) Total Environmental Costs ($)	(10) Projected Effective Sales at Meter Level (mWh)	(11) Environmental Cost Recovery Factors (cents/kWh)
Residential											
RS-1, RST-1, RSL-1, RSL-2, RSS-1											
Secondary	50.554%	62.735%	56.644%	63.795%	$110,820,902	$210,111	$5,609,708	$3,205,729	$119,846,450	18,303,702	0.655
General Service Non-Demand											
GS-1, GST-1											
Secondary										1,120,052	0.647
Primary										7,221	0.641
Transmission										3,503	0.634
TOTAL GS	3.122%	2.754%	2.938%	3.353%	$6,844,853	$9,224	$294,804	$166,291	$7,315,172	1,130,776	
General Service											
GS-2 Secondary	0.238%	0.146%	0.192%	0.108%	$521,988	$489	$9,539	$10,869	$542,884	86,214	0.630
General Service Demand											
GSD-1, GSDT-1, SS-1											
Secondary										11,831,271	0.636
Primary										2,234,837	0.630
Transmission										15,881	0.623
TOTAL GSD	38.750%	30.240%	34.495%	28.604%	$84,946,323	$101,281	$2,532,844	$1,952,236	$89,532,684	14,081,989	
Curtailable											
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3											
Secondary										-	0.635
Primary										176,488	0.629
Transmission										-	0.622
TOTAL CS	0.476%	0.330%	0.403%	0.594%	$1,043,942	$1,106	$52,231	$22,819	$1,120,097	176,488	
Interruptible											
IS-1, IST-1, IS-2, IST-2, SS-2											
Secondary										98,446	0.615
Primary										1,727,314	0.609
Transmission										348,760	0.603
TOTAL IS	5.874%	3.677%	4.776%	2.408%	$12,875,936	$12,316	$211,777	$270,266	$13,370,295	2,174,521	
Sub-Total Curtailable/Interruptible											
IS-1, IST-1, IS-2, IST-2, SS-2											
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3											
Secondary										98,446	0.616
Primary										1,903,803	0.610
Transmission										348,760	0.604
TOTAL IS	6.350%	4.008%	5.179%	3.002%	$13,919,877	$13,422	$264,008	$293,085	$14,490,392	2,351,009	
Lighting											
LS-1 Secondary	0.986%	0.117%	0.552%	0.937%	$2,160,813	$393	$82,434	$31,212	$2,274,852	356,890	0.637
	100.000%	100.000%	100.000%	100.000%	$219,214,756	$334,920	$8,793,336	$5,659,422	$234,002,435	36,310,579	0.644

Notes:
(1) From Form 42-6P 50%, Column 9
(2) From Form 42-6P 50%, Column 10
(3) From Form 42-6P 50%, Column 11
(4) From Form 42-6P 50%, 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 2009 to December 2009
(11) Column 7/ Column 8 x 100

Form 42-7P

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of Environmental Cost Recovery Clause Rate Factors by Rate Class
JANUARY 2010 - DECEMBER 2010

Rate Class	(1) mWh Sales at Source Energy Allocator (%)	(2) 12CP Transmission Allocator (%)	(3) 12CP & 25% AD Demand Allocator (%)	(4) NCP Distribution Allocator (%)	(5) Energy-Related Costs ($)	(6) Transmission Demand Costs ($)	(7) Distribution Demand Costs ($)	(8) Production Demand Costs ($)	(9) Total Environmental Costs ($)	(10) Projected Effective Sales at Meter Level (mWh)	(11) Environmental Cost Recovery Factors (cents/kWh)
Residential											
RS-1, RST-1, RSL-1, RSL-2, RSS-1											
Secondary	50.554%	62.736%	59.689%	63.795%	$110,620,902	$210,111	$5,809,708	$3,378,073	$120,018,794	18,303,702	0.656
General Service Non-Demand											
GS-1, GST-1											
Secondary										1,120,052	0.646
Primary										7,221	0.640
Transmission										3,503	0.633
TOTAL GS	3.122%	2.754%	2.846%	3.353%	$6,844,853	$9,224	$294,804	$161,081	$7,309,962	1,130,776	
General Service											
GS-2 Secondary	0.238%	0.146%	0.169%	0.108%	$521,988	$489	$9,539	$9,565	$541,580	86,214	0.628
General Service Demand											
GSD-1, GSDT-1, SS-1											
Secondary										11,831,271	0.636
Primary										2,234,837	0.629
Transmission										15,881	0.622
TOTAL GSD	38.750%	30.240%	32.368%	28.804%	$84,946,323	$101,281	$2,532,844	$1,831,833	$89,412,281	14,081,989	
Curtailable											
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3											
Secondary										-	0.633
Primary										176,488	0.627
Transmission										-	0.620
TOTAL CS	0.476%	0.330%	0.367%	0.594%	$1,043,942	$1,106	$52,231	$20,753	$1,118,031	176,488	
Interruptible											
IS-1, IST-1, IS-2, IST-2, SS-2											
Secondary										98,446	0.613
Primary										1,727,314	0.607
Transmission										348,760	0.601
TOTAL IS	5.874%	3.677%	4.226%	2.408%	$12,875,936	$12,316	$211,777	$239,192	$13,339,221	2,174,521	
Sub-Total Curtailable/Interruptible											
IS-1, IST-1, IS-2, IST-2, SS-2											
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3											
Secondary										98,446	0.615
Primary										1,903,803	0.609
Transmission										348,760	0.603
TOTAL IS	6.350%	4.006%	4.593%	3.002%	$13,919,877	$13,422	$264,008	$259,944	$14,457,252	2,351,009	
Lighting											
LS-1 Secondary	0.986%	0.117%	0.334%	0.937%	$2,160,813	$393	$82,434	$18,926	$2,262,565	356,890	0.634
	100.000%	100.000%	100.000%	100.000%	$219,214,756	$334,920	$8,793,336	$5,659,422	$234,002,435	36,310,579	0.644

Notes:

(1) From Form 42-6P 25%, Column 9
(2) From Form 42-6P 25%, Column 10
(3) From Form 42-6P 25%, Column 11
(4) From Form 42-6P 25%, 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 2009 to December 2009
(11) Column 7/ Column 8 x 100

Docket No. 090007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. ___ (TGF-3)

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of Environmental Cost Recovery Clause Rate Factors by Rate Class
JANUARY 2010 - DECEMBER 2010

Form 42-7P

Rate Class	(1) mWh Sales at Source Energy Allocator (%)	(2) 12CP Transmission Allocator (%)	(3) 12CP & 1/13th AD Demand Allocator (%)	(4) NCP Distribution Allocator (%)	(5) Energy-Related Costs ($)	(6) Transmission Demand Costs ($)	(7) Distribution Demand Costs ($)	(8) Production Demand Costs ($)	(9) Total Environmental Costs ($)	(10) Projected Effective Sales at Meter Level (mWh)	(11) Environmental Cost Recovery Factors (cents/kWh)
Residential											
RS-1, RST-1, RSL-1, RSL-2, RSS-1											
Secondary	50.554%	62.735%	61.798%	63.795%	$110,620,902	$210,111	$5,609,708	$3,497,389	$120,138,109	16,303,702	0.666
General Service Non-Demand											
GS-1, GST-1											
Secondary										1,120,052	0.646
Primary										7,221	0.640
Transmission										3,503	0.633
TOTAL GS	3.122%	2.754%	2.783%	3.353%	$6,844,853	$9,224	$294,804	$157,474	$7,306,355	1,130,776	
General Service											
GS-2 Secondary	0.236%	0.146%	0.153%	0.106%	$521,988	$489	$9,539	$8,662	$540,678	86,214	0.627
General Service Demand											
GSD-1, GSDT-1, SS-1											
Secondary										11,831,271	0.634
Primary										2,234,837	0.628
Transmission										15,881	0.621
TOTAL GSD	38.750%	30.240%	30.895%	28.804%	$84,946,323	$101,281	$2,532,844	$1,748,477	$89,328,925	14,081,989	
Curtailable											
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3											
Secondary										-	0.633
Primary										176,488	0.627
Transmission										-	0.620
TOTAL CS	0.476%	0.330%	0.341%	0.594%	$1,043,942	$1,106	$52,231	$19,322	$1,116,601	176,488	
Interruptible											
IS-1, IST-1, IS-2, IST-2, SS-2											
Secondary										98,446	0.612
Primary										1,727,314	0.606
Transmission										348,760	0.600
TOTAL IS	5.874%	3.677%	3.846%	2.408%	$12,875,936	$12,316	$211,777	$217,678	$13,317,707	2,174,521	
Sub-Total Curtailable/Interruptible											
IS-1, IST-1, IS-2, IST-2, SS-2											
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3											
Secondary										98,446	0.614
Primary										1,903,803	0.608
Transmission										348,760	0.602
TOTAL IS	6.350%	4.006%	4.186%	3.002%	$13,919,877	$13,422	$264,008	$237,001	$14,434,308	2,351,009	
Lighting											
LS-1 Secondary	0.966%	0.117%	0.184%	0.937%	$2,160,813	$393	$82,434	$10,420	$2,254,059	356,890	0.632
	100.000%	100.000%	100.000%	100.000%	$219,214,756	$334,920	$8,793,336	$5,659,422	$234,002,435	36,310,579	0.644

Notes:
(1) From Form 42-6P 12 & 1/13, Column 9
(2) From Form 42-6P 12 & 1/13, Column 10
(3) From Form 42-6P 12 & 1/13, Column 11
(4) From Form 42-6P 12 & 1/13, 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 2009 to December 2009
(11) Column 7/ Column 8 x 100

DOCKET NO. 090007-EI
FINAL ECRC 2008 TRUE-UP
EXHIBIT HTB-1

INDEX

TAMPA ELECTRIC COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE

FINAL TRUE-UP AMOUNT FOR THE PERIOD OF JANUARY 2008 THROUGH DECEMBER 2008

FORMS 42-1A THROUGH 42-8A

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 28
COMPANY Tampa Electric Company (Direct)
WITNESS Howard T. Bryant (HTB-1)
DATE 11/02/09

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2008 to December 2008
(in Dollars)

Form 42 - 1A

Line		Period Amount
1.	End of Period Actual True-Up for the Period January 2008 to December 2008 (Form 42-2A, Lines 5 + 6 + 10)	($15,866,217)
2.	Estimated/Actual True-Up Amount Approved for the Period January 2008 to December 2008 (Order No. PSC-08-0775 FOF-EI)	(7,753,224)
3.	Final True-Up to be Refunded/(Recovered) in the Projection Period January 2010 to December 2010 (Lines 1 - 2)	($8,112,993)

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2008 to December 2008

Form 42 - 2A

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 Total
1.	ECRC Revenues (net of Revenue Taxes)	$1,638,579	$1,370,190	$1,402,163	$1,497,358	$1,604,847	$1,896,228	$1,838,115	$1,859,793	$1,976,888	$1,751,627	$1,464,969	$1,484,593	$19,785,350
2.	True-Up Provision	(189,293)	(189,293)	(189,293)	(189,293)	(189,293)	(189,293)	(189,293)	(189,293)	(189,293)	(189,293)	(189,293)	(189,287)	(2,271,510)
3.	ECRC Revenues Applicable to Period (Lines 1 + 2)	1,449,286	1,180,897	1,212,870	1,308,065	1,415,554	1,706,935	1,648,822	1,670,500	1,787,595	1,562,334	1,275,676	1,295,306	17,513,840
4.	Jurisdictional ECRC Costs													
	a. O & M Activities (Form 42-5A, Line 9)	934,271	952,608	(142,256)	828,339	63,219	997,223	(77,784)	1,171,490	(1,883,087)	1,590,404	(3,475,832)	1,714,251	2,672,846
	b. Capital Investment Projects (Form 42-7A, Line 9)	2,134,304	2,110,308	2,120,016	2,105,726	2,116,026	2,149,067	2,919,008	3,010,781	3,014,505	3,029,460	3,035,487	3,067,296	30,811,984
	c. Total Jurisdictional ECRC Costs	3,068,575	3,062,916	1,977,760	2,934,065	2,179,245	3,146,290	2,841,224	4,182,271	1,131,418	4,619,864	(440,345)	4,781,547	33,484,830
5.	Over/Under Recovery (Line 3 - Line 4c)	(1,619,289)	(1,882,019)	(764,890)	(1,626,000)	(763,691)	(1,439,355)	(1,192,402)	(2,511,771)	656,177	(3,057,530)	1,716,021	(3,486,241)	(15,970,990)
6.	Interest Provision (Form 42-3A, Line 10)	31,846	20,427	16,266	13,326	10,676	8,020	5,778	2,398	1,353	(1,878)	(1,950)	(1,489)	104,773
7.	Beginning Balance True-Up & Interest Provision	(2,271,510)	(3,669,660)	(5,341,959)	(5,901,290)	(7,324,671)	(7,888,393)	(9,130,435)	(10,127,766)	(12,447,846)	(11,601,023)	(14,471,138)	(12,567,774)	(2,271,510)
	a. Deferred True-Up from January to December 2007 (Order No. PSC-08-0775-FOF-EI)	12,464,395	12,464,395	12,464,395	12,464,395	12,464,395	12,464,395	12,464,395	12,464,395	12,464,395	12,464,395	12,464,395	12,464,395	12,464,395
8.	True-Up Collected/(Refunded) (see Line 2)	189,293	189,293	189,293	189,293	189,293	189,293	189,293	189,293	189,293	189,293	189,293	189,287	2,271,510
9.	End of Period Total True-Up (Lines 5+6+7+7a+8)	8,794,735	7,122,436	6,563,105	5,139,724	4,576,002	3,333,960	2,336,629	16,549	863,372	(2,006,743)	(103,379)	(3,401,822)	(3,401,822)
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)	$8,794,735	$7,122,436	$6,563,105	$5,139,724	$4,576,002	$3,333,960	$2,336,629	$16,549	$863,372	($2,006,743)	($103,379)	($3,401,822)	($3,401,822)

DOCKET NO. 090007-EI
ECRC 2008 FINAL TRUE-UP
EXHIBIT HTB-1, DOC. NO. 2, PAGE 1 OF 1

Form 42 - 1P
REVISED 10/19/09

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to Be Recovered

For the Projected Period
January 2010 to December 2010

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)	$18,046,706	$168,214	$18,214,920
b. Projected Capital Projects (Form 42-3P, Lines 7, 8 & 9)	57,071,583	149,366	57,220,949
c. Total Jurisdictional Revenue Requirements for the projected period (Lines 1a + 1b)	75,118,289	317,580	75,435,869
2. True-up for Estimated Over/(Under) Recovery for the current period January 2009 to December 2009* (Form 42-2E, Line 5 + 6 + 10)	(9,193,784)	(85,345)	(9,279,129)
3. Final True-up for the period January 2008 to December 2008 (Form 42-1A, Line 3)	(7,994,185)	(118,808)	(8,112,993)
4. Total Jurisdictional Amount to Be Recovered/(Refunded) in the projection period January 2010 to December 2010 (Line 1 - Line 2- Line 3)	92,306,258	521,733	92,827,991
5. Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier)	$92,372,719	$522,109	$92,894,828

* 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. 090007-EI
ECRC 2010 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 1

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2008 to December 2008

Form 42 - 4A

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	$ 3,342,509	$ 3,287,684	$ 54,825	1.7%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0.0%
	c. SO_2 Emissions Allowances	(11,656,193)	(18,765,601)	7,109,408	37.9%
	d. Big Bend Units 1 & 2 FGD	7,542,688	6,337,155	1,205,533	19.0%
	e. Big Bend PM Minimization and Monitoring	312,943	438,402	(125,459)	-28.6%
	f. Big Bend NO_x Emissions Reduction	475,890	512,435	(36,545)	-7.1%
	g. NPDES Annual Surveillance Fees	34,500	34,500	0	0.0%
	h. Gannon Thermal Discharge Study	86,335	76,005	10,330	13.6%
	i. Polk NO_x Emissions Reduction	38,246	46,667	(8,421)	-18.0%
	j. Bayside SCR Consumables	146,098	108,068	38,030	35.2%
	k. Big Bend Unit 4 SOFA	24,282	32,976	(8,694)	-26.4%
	l. Big Bend Unit 1 Pre-SCR	0	30,000	(30,000)	-100.0%
	m. Big Bend Unit 2 Pre-SCR	6,951	11,188	(4,237)	-37.9%
	n. Big Bend Unit 3 Pre-SCR	2	2	0	0.0%
	o. Clean Water Act Section 316(b) Phase II Study	149,902	124,395	25,507	20.5%
	p. Arsenic Groundwater Standard Program	72,656	98,651	(25,995)	-26.4%
	q. Big Bend 3 SCR	899,642	1,200,000	(300,358)	-25.0%
	r. Big Bend 4 SCR	1,301,024	1,331,036	(30,012)	-2.3%
2.	Total Investment Projects - Recoverable Costs	$2,777,475	($5,096,437)	$7,873,912	154.5%
3.	Recoverable Costs Allocated to Energy	$2,434,082	($5,429,988)	$7,864,070	144.8%
4.	Recoverable Costs Allocated to Demand	$343,393	$333,551	$9,842	3.0%

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-08-0775-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Form 42-3P
REVISED 10/19/09

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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 Desulfurization Integration	$64,538	$64,385	$64,232	$64,079	$63,925	$63,771	$63,619	$63,465	$63,312	$63,158	$63,005	$62,852	$764,341		$764,341
b.	Big Bend Units 1 and 2 Flue Gas Conditioning	35,893	35,763	35,632	35,503	35,373	35,242	35,112	34,981	34,852	34,721	34,591	34,461	422,124		422,124
c.	Big Bend Unit 4 Continuous Emissions Monitors	6,623	6,609	6,594	6,579	6,565	6,550	6,535	6,520	6,506	6,491	6,476	6,462	78,510		78,510
d.	Big Bend Fuel Oil Tank # 1 Upgrade	4,480	4,471	4,460	4,450	4,439	4,428	4,418	4,408	4,397	4,387	4,376	4,365	53,079	$ 53,079	
e.	Big Bend Fuel Oil Tank # 2 Upgrade	7,370	7,352	7,335	7,319	7,301	7,284	7,267	7,249	7,232	7,215	7,197	7,181	87,302	87,302	
f.	Phillips Upgrade Tank # 1 for FDEP	480	478	477	476	474	473	472	470	469	468	466	464	5,667	5,667	
g.	Phillips Upgrade Tank # 4 for FDEP	754	751	750	747	745	743	740	738	736	734	731	730	8,899	8,899	
h.	Big Bend Unit 1 Classifier Replacement	11,343	11,308	11,273	11,237	11,202	11,167	11,132	11,097	11,062	11,027	10,991	10,956	133,795		133,795
i.	Big Bend Unit 2 Classifier Replacement	8,217	8,193	8,167	8,143	8,118	8,094	8,069	8,044	8,019	7,995	7,970	7,945	96,974		96,974
j.	Big Bend Section 114 Mercury Testing Platform	1,119	1,118	1,115	1,114	1,111	1,110	1,107	1,106	1,103	1,102	1,100	1,098	13,303		13,303
k.	Big Bend Units 1 & 2 FGD (Less Gypsum Revenue)	736,939	737,118	737,289	735,721	741,734	739,684	737,635	735,585	733,536	731,487	729,437	727,387	8,823,552		8,823,552
l.	Big Bend FGD Optimization and Utilization	208,518	208,113	207,709	207,304	206,901	206,496	206,092	205,687	205,283	204,879	204,474	204,070	2,475,526		2,475,526
m.	Big Bend NO_x Emissions Reduction	67,476	67,390	67,304	67,217	67,130	67,043	66,957	66,870	66,784	66,697	66,610	66,524	804,002		804,002
n.	Big Bend PM Minimization and Monitoring	89,789	89,654	89,452	89,249	89,046	88,843	88,640	88,437	88,234	88,032	87,829	87,626	1,064,831		1,064,831
o.	Polk NO_x Emissions Reduction	16,537	16,494	16,451	16,408	16,365	16,323	16,279	16,236	16,193	16,150	16,108	16,065	195,609		195,609
p.	Big Bend Unit 4 SOFA	26,770	26,720	26,671	26,621	26,572	26,521	26,472	26,422	26,373	26,323	26,274	26,223	317,962		317,962
q.	Big Bend Unit 1 Pre-SCR	22,533	22,489	22,444	22,400	22,356	22,312	22,268	22,224	22,180	22,136	22,092	22,048	267,482		267,482
r.	Big Bend Unit 2 Pre-SCR	18,017	17,978	17,938	17,898	17,859	17,819	17,779	17,740	17,700	17,660	17,621	17,581	213,590		213,590
s.	Big Bend Unit 3 Pre-SCR	30,888	30,832	30,774	30,718	30,662	30,606	30,550	30,493	30,436	30,380	30,324	30,268	366,931		366,931
t.	Big Bend Unit 1 SCR	0	0	0	0	889,336	1,186,187	1,185,685	1,183,181	1,180,677	1,178,174	1,175,670	1,173,167	9,152,077		9,152,077
u.	Big Bend Unit 2 SCR	1,102,544	1,100,274	1,098,003	1,095,733	1,093,462	1,091,192	1,088,921	1,086,651	1,084,381	1,082,110	1,079,840	1,077,568	13,080,679		13,080,679
v.	Big Bend Unit 3 SCR	901,949	900,329	898,710	897,090	895,469	893,849	892,230	890,610	888,989	887,369	885,750	884,130	10,716,474		10,716,474
w.	Big Bend Unit 4 SCR	678,425	677,237	676,049	674,861	673,673	672,485	671,297	670,109	668,920	667,732	666,544	665,356	8,062,688		8,062,688
x.	Big Bend FGD System Reliability	129,171	128,955	128,739	128,523	128,306	129,303	131,514	134,939	140,791	145,914	148,369	150,094	1,624,618		1,624,618
y.	Clean Air Mercury Rule	13,846	13,818	13,888	14,006	13,976	13,950	13,920	13,892	13,864	13,835	13,807	13,779	166,583		166,583
z.	SO_2 Emissions Allowances (B)	(393)	(390)	(387)	(385)	(382)	(378)	(375)	(372)	(369)	(365)	(362)	(358)	(4,516)		(4,516)
	Total Investment Projects - Recoverable Costs	4,183,826	4,177,439	4,171,069	4,163,011	5,051,720	5,341,097	5,334,335	5,326,782	5,321,660	5,315,811	5,307,290	5,298,042	58,992,082	$ 154,947	$ 58,837,135
3.	Recoverable Costs Allocated to Energy	4,170,742	4,164,387	4,158,047	4,150,019	5,038,761	5,328,169	5,321,438	5,313,917	5,308,826	5,303,007	5,294,520	5,285,302	58,837,135		
4.	Recoverable Costs Allocated to Demand	13,084	13,052	13,022	12,992	12,959	12,928	12,897	12,865	12,834	12,804	12,770	12,740	154,947		
5.	Retail Energy Jurisdictional Factor	0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374			
6.	Retail Demand Jurisdictional Factor	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735			
7.	Jurisdictional Energy Recoverable Costs (C)	4,078,518	4,051,001	4,052,893	4,028,512	4,851,813	5,172,135	5,153,576	5,125,551	5,133,985	5,120,588	5,139,602	5,163,409	57,071,583		
8.	Jurisdictional Demand Recoverable Costs (D)	12,613	12,582	12,553	12,524	12,492	12,462	12,432	12,402	12,372	12,343	12,310	12,281	149,366		
9.	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$4,091,131	$4,063,583	$4,065,446	$4,041,036	$4,864,305	$5,184,597	$5,166,008	$5,137,953	$5,146,357	$5,132,931	$5,151,912	$5,175,690	$57,220,949		

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. 090007-EI
ECRC 2010 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 3

Form 42 - 6A

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2008 to December 2008

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

Line		(1) Actual	(2) Actual/Estimated Projection	(3) Variance Amount	(4) Percent
1.	Description of Investment Projects				
	a. Big Bend Unit 3 Flue Gas Desulfurization Integration	$808,109	$808,109	$0	0.0%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	459,431	459,431	0	0.0%
	c. Big Bend Unit 4 Continuous Emissions Monitors	82,704	82,704	0	0.0%
	d. Big Bend Fuel Oil Tank # 1 Upgrade	56,068	56,068	0	0.0%
	e. Big Bend Fuel Oil Tank # 2 Upgrade	92,212	92,212	0	0.0%
	f. Phillips Upgrade Tank # 1 for FDEP	6,064	6,064	0	0.0%
	g. Phillips Upgrade Tank # 4 for FDEP	9,528	9,528	0	0.0%
	h. Big Bend Unit 1 Classifier Replacement	143,853	143,853	0	0.0%
	i. Big Bend Unit 2 Classifier Replacement	104,046	104,046	0	0.0%
	j. Big Bend Section 114 Mercury Testing Platform	13,858	13,858	0	0.0%
	k. Big Bend Units 1 & 2 FGD	8,916,407	8,920,859	(4,452)	0.0%
	l. Big Bend FGD Optimization and Utilization	2,590,639	2,590,639	0	0.0%
	m. Big Bend NO_x Emissions Reduction	797,443	798,805	(1,362)	-0.2%
	n. Big Bend PM Minimization and Monitoring	1,075,671	1,084,033	(8,362)	-0.8%
	o. Polk NO_x Emissions Reduction	207,879	207,879	0	0.0%
	p. Big Bend Unit 4 SOFA	332,096	332,096	0	0.0%
	q. Big Bend Unit 1 Pre-SCR	280,044	280,044	0	0.0%
	r. Big Bend Unit 2 Pre-SCR	224,909	224,909	0	0.0%
	s. Big Bend Unit 3 Pre-SCR	361,148	356,032	5,116	1.4%
	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	5,423,825	5,437,189	(13,364)	-0.2%
	w. Big Bend Unit 4 SCR	8,407,763	8,408,013	(250)	0.0%
	x. Big Bend FGD System Reliability	1,526,247	1,532,141	(5,894)	-0.4%
	y. Clean Air Mercury Rule	71,609	70,383	1,226	1.7%
	z. SO_2 Emissions Allowances	(6,513)	(5,743)	(770)	-13.4%
2.	Total Investment Projects - Recoverable Costs	$31,985,040	$32,013,152	($28,112)	-0.1%
3.	Recoverable Costs Allocated to Energy	$31,821,168	$31,849,280	($28,112)	-0.1%
4.	Recoverable Costs Allocated to Demand	$163,872	$163,872	$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-08-0775-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

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Form 42-7A

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2008 to December 2008

Capital Investment Projects-Recoverable Costs

(in Dollars)

Line		Description (A)	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 Total	Method of Classification Demand	Method of Classification Energy
1.	a.	Big Bend Unit 3 Flue Gas Desulfurization 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	750,451	748,492	746,532	744,573	742,637	741,193	741,160	740,684	738,819	737,109	738,520	746,237	8,916,407		8,916,407
	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	66,231	66,150	66,069	66,004	65,954	65,903	65,939	66,456	67,136	67,342	67,202	67,057	797,443		797,443
	n.	Big Bend PM Minimization and Monitoring	90,591	90,396	90,199	90,004	89,807	89,612	89,415	89,220	89,075	89,082	89,109	89,161	1,075,671		1,075,671
	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	23,579	23,539	23,499	23,451	23,401	23,357	23,313	23,269	23,225	23,181	23,137	23,093	280,044		280,044
	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	22,793	25,253	25,918	29,315	32,464	32,031	31,975	32,386	32,337	32,282	32,226	32,168	361,148		361,148
	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	815,255	923,533	922,724	921,641	920,542	920,130	5,423,825		5,423,825
	w.	Big Bend Unit 4 SCR	707,557	706,732	705,859	705,392	702,934	700,469	699,413	698,254	697,070	695,882	694,694	693,507	8,407,763		8,407,763
	x.	Big Bend FGD System Reliability	110,065	114,980	117,554	125,303	132,098	132,395	132,498	132,528	132,470	132,351	132,117	131,888	1,526,247		1,526,247
	y.	Clean Air Mercury Rule	1,934	3,617	5,799	6,334	6,383	6,412	6,434	6,466	6,537	6,607	6,733	8,353	71,609		71,609
	z.	SO_2 Emissions Allowances (B)	(648)	(616)	(603)	(590)	(577)	(564)	(550)	(534)	(494)	(453)	(445)	(439)	(6,513)		(6,513)
2.		Total Investment Projects - Recoverable Costs	2,205,269	2,210,332	2,211,685	2,219,721	2,224,108	2,218,890	3,032,005	3,138,486	3,134,195	3,129,398	3,127,277	3,133,674	31,985,040	$ 163,872	$ 31,821,168
3.		Recoverable Costs Allocated to Energy	2,191,441	2,196,536	2,197,921	2,205,986	2,210,406	2,205,218	3,018,364	3,124,877	3,120,618	3,115,850	3,113,762	3,120,189	31,821,168		
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	0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701			
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)	2,120,937	2,096,972	2,106,711	2,092,449	2,102,781	2,135,851	2,905,822	2,997,626	3,001,380	3,016,363	3,022,422	3,054,260	30,653,574		
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)	$2,134,304	$2,110,308	$2,120,016	$2,105,726	$2,116,026	$2,149,067	$2,919,008	$3,010,781	$3,014,505	$3,029,460	$3,035,487	$3,067,296	$30,811,984		

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 page 26, Line 6
(C) Line 3 x Line 5
(D) Line 4 x Line 6

DOCKET NO. 090007-EI
ECRC 2008 FINAL TRUE-UP
EXHIBIT HTB-1, DOC. NO. 7, PAGE 1 OF 1

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
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	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 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		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
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)		65,991	64,948	65,062	64,239	64,282	65,298	64,758	64,380	64,401	64,673	64,698	65,095	777,825
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)		$65,991	$64,948	$65,062	$64,239	$64,282	$65,298	$64,758	$64,380	$64,401	$64,673	$64,698	$65,095	$777,825

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 Final True-Up Amount for the Period
January 2008 to December 2008

Form 42-8A
Page 2 of 26

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	Actual July	Actual August	Actual September	Actual October	Actual November	Actual 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) (B)	$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 (C)		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 (D)		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		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
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 (E)		37,746	37,110	37,133	36,624	36,607	37,145	36,796	36,540	36,510	36,623	36,594	36,777	442,205
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)		$37,746	$37,110	$37,133	$36,624	$36,607	$37,145	$36,796	$36,540	$36,510	$36,623	$36,594	$36,777	$442,205

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,676,217) and 312.42 ($2,341,517)
(B) Net investment is comprised of several projects having various depreciation rates.
(C) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(D) Applicable depreciation rates are 3.3% and 3.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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ECRC 2008 FINAL 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 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	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 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		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
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)		6,749	6,643	6,655	6,572	6,577	6,683	6,627	6,590	6,593	6,623	6,626	6,667	79,605
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)		$6,749	$6,643	$6,655	$6,572	$6,577	$6,683	$6,627	$6,590	$6,593	$6,623	$6,626	$6,667	$79,605

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

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
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	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 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	(120,686)	(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		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
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 Final True-Up Amount for the Period
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	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 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		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
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 Final True-Up Amount for the Period
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	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 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		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
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 Final True-Up Amount for the Period
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	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 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		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
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 Final True-Up Amount for the Period
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	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 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		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
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)		11,789	11,595	11,607	11,454	11,454	11,628	11,524	11,449	11,445	11,486	11,482	11,546	138,459
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)		$11,789	$11,595	$11,607	$11,454	$11,454	$11,628	$11,524	$11,449	$11,445	$11,486	$11,482	$11,546	$138,459

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 Final True-Up Amount for the Period
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	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 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		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
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)		8,523	8,384	8,394	8,283	8,284	8,410	8,335	8,281	8,280	8,310	8,308	8,355	100,147
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$8,523	$8,384	$8,394	$8,283	$8,284	$8,410	$8,335	$8,281	$8,280	$8,310	$8,308	$8,355	$100,147

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 Final True-Up Amount for the Period
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	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 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		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
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)		1,128	1,110	1,114	1,099	1,102	1,120	1,111	1,105	1,106	1,111	1,112	1,120	13,338
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)		$1,128	$1,110	$1,114	$1,099	$1,102	$1,120	$1,111	$1,105	$1,106	$1,111	$1,112	$1,120	$13,338

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 Final True-Up Amount for the Period
January 2008 to December 2008

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	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$4,739	$101,681	$295,181	$10,638	$8,782	$42,614	$651,422	$1,342,633	$2,457,690
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	2,390	0	2,390
	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	$83,555,351	$83,555,351	
3.	Less: Accumulated Depreciation	(26,920,908)	(27,122,828)	(27,324,748)	(27,526,668)	(27,728,588)	(27,930,508)	(28,132,428)	(28,334,348)	(28,536,268)	(28,738,188)	(28,940,108)	(29,142,031)	(29,343,956)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	4,739	106,420	401,601	412,239	421,021	463,635	1,112,667	2,455,300	
5.	Net Investment (Lines 2 + 3 + 4) (B)	$56,632,053	56,430,133	56,228,213	56,026,293	55,824,373	55,627,191	55,526,952	55,620,214	55,428,932	55,235,794	55,076,488	55,525,987	56,666,695	
6.	Average Net Investment		56,531,093	56,329,173	56,127,253	55,925,333	55,725,782	55,577,071	55,573,583	55,524,573	55,332,363	55,156,141	55,301,237	56,096,341	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (C)		415,683	414,198	412,713	411,228	409,761	408,667	408,642	408,281	406,868	405,572	406,639	412,486	$4,920,738
	b. Debt Component (Line 6 x 2.82% x 1/12)		132,848	132,374	131,899	131,425	130,956	130,606	130,598	130,483	130,031	129,617	129,958	131,826	1,572,621
8.	Investment Expenses														
	a. Depreciation (D)		201,920	201,920	201,920	201,920	201,920	201,920	201,920	201,920	201,920	201,920	201,923	201,925	2,423,048
	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)		750,451	748,492	746,532	744,573	742,637	741,193	741,160	740,684	738,819	737,109	738,520	746,237	8,916,407
	a. Recoverable Costs Allocated to Energy		750,451	748,492	746,532	744,573	742,637	741,193	741,160	740,684	738,819	737,109	738,520	746,237	8,916,407
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
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 (E)		726,307	714,564	715,552	706,251	706,478	717,878	713,525	710,522	710,589	713,574	716,856	730,469	8,582,565
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)		$726,307	$714,564	$715,552	$706,251	$706,478	$717,876	$713,525	$710,522	$710,589	$713,574	$716,856	$730,469	$8,582,565

Notes:
(A) Applicable depreciable base for Big Bend; account 312.46
(B) Net investment is comprised of several projects having various depreciation rates.
(C) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(D) Applicable depreciation rates are 2.9%
(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 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	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 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) (B)	$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 (C)		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 (D)		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		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
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 (E)		211,092	207,836	208,283	205,734	205,952	209,292	207,642	206,513	206,666	207,625	207,789	209,149	2,493,573
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)		$211,092	$207,836	$208,283	$205,734	$205,952	$209,292	$207,642	$206,513	$206,666	$207,625	$207,789	$209,149	$2,493,573

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 1.5% and 2.3%
(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 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	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 Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$2,745	$2,352	$2,803	$16,829	$84,267	$44,311	$4,501	($14,161)	$3,927	$147,574
	b. Clearings to Plant		0	0	0	2,745	2,352	2,803	16,829	84,267	44,311	4,501	(14,161)	3,927	$147,574
	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)	$3,190,853	$3,190,853	$3,190,853	$3,190,853	$3,193,598	$3,195,950	$3,198,753	$3,215,582	$3,299,849	$3,344,160	$3,348,661	$3,334,500	$3,338,427	
3.	Less: Accumulated Depreciation	2,779,586	2,771,247	2,762,908	2,754,569	2,746,227	2,737,879	2,729,526	2,721,151	2,712,667	2,704,044	2,695,368	2,686,702	2,678,047	
4.	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)	$5,970,439	5,962,100	5,953,761	5,945,422	5,939,825	5,933,829	5,928,279	5,936,733	6,012,516	6,048,204	6,044,029	6,021,202	6,016,474	
6.	Average Net Investment		5,966,270	5,957,931	5,949,592	5,942,624	5,936,827	5,931,054	5,932,506	5,974,625	6,030,360	6,046,117	6,032,616	6,018,838	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (C)		43,871	43,810	43,748	43,697	43,654	43,612	43,623	43,932	44,342	44,458	44,359	44,258	$527,364
	b. Debt Component (Line 6 x 2.82% x 1/12)		14,021	14,001	13,982	13,965	13,952	13,938	13,941	14,040	14,171	14,208	14,177	14,144	168,540
8.	Investment Expenses														
	a. Depreciation (D)		8,339	8,339	8,339	8,342	8,348	8,353	8,375	8,484	8,623	8,676	8,666	8,655	101,539
	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)		66,231	66,150	66,069	66,004	65,954	65,903	65,939	66,456	67,136	67,342	67,202	67,057	797,443
	a. Recoverable Costs Allocated to Energy		66,231	66,150	66,069	66,004	65,954	65,903	65,939	66,456	67,136	67,342	67,202	67,057	797,443
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
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 (E)		64,100	63,152	63,327	62,607	62,743	63,830	63,480	63,750	64,571	65,192	65,231	65,640	767,623
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)		$64,100	$63,152	$63,327	$62,607	$62,743	$63,830	$63,480	$63,750	$64,571	$65,192	$65,231	$65,640	$767,623

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,675,171), 312.42 ($1,075,718), and 312.43 ($587,538)
(B) Net investment is comprised of several projects having various depreciation rates.
(C) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(D) Applicable depreciation rates are 3.3%, 3.1%, and 2.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
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	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 Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$10,663	$31,128	$14,944	$35,892	$92,627
	b. Clearings to Plant		0	0	0	0	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	(725,979)	(746,174)	(766,369)	(786,564)	(806,759)	(826,954)	(847,149)	(867,344)	(887,539)	(907,734)	(927,929)	(948,124)	(968,319)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	10,663	41,791	56,735	92,627	
5.	Net Investment (Lines 2 + 3 + 4) (B)	$7,265,073	7,244,878	7,224,683	7,204,488	7,184,293	7,164,098	7,143,903	7,123,708	7,103,513	7,093,981	7,104,914	7,099,663	7,115,360	
6.	Average Net Investment		7,254,976	7,234,781	7,214,586	7,194,391	7,174,196	7,154,001	7,133,806	7,113,611	7,098,747	7,099,448	7,102,289	7,107,512	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (C)		53,347	53,199	53,050	52,902	52,753	52,605	52,456	52,308	52,198	52,203	52,224	52,263	$631,508
	b. Debt Component (Line 6 x 2.82% x 1/12)		17,049	17,002	16,954	16,907	16,859	16,812	16,764	16,717	16,682	16,684	16,690	16,703	201,823
8.	Investment Expenses														
	a. Depreciation (D)		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)		90,591	90,396	90,199	90,004	89,807	89,612	89,415	89,220	89,075	89,082	89,109	89,161	1,075,671
	a. Recoverable Costs Allocated to Energy		90,591	90,396	90,199	90,004	89,807	89,612	89,415	89,220	89,075	89,082	89,109	89,161	1,075,671
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
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 (E)		87,676	86,299	86,456	85,372	85,434	86,793	86,081	85,587	85,671	86,238	86,495	87,277	1,035,379
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)		$87,676	$86,299	$86,456	$85,372	$85,434	$86,793	$86,081	$85,587	$85,671	$86,238	$86,495	$87,277	$1,035,379

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) Net investment is comprised of several projects having various depreciation rates.
(C) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(D) Applicable depreciation rates are 3.3%, 3.1%, 2.6%, 2.5%, and 2.1%
(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 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	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 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		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
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)		16,994	16,723	16,748	16,534	16,541	16,799	16,657	16,555	16,558	16,625	16,628	16,726	200,088
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$16,994	$16,723	$16,748	$16,534	$16,541	$16,799	$16,657	$16,555	$16,558	$16,625	$16,628	$16,726	$200,088

Notes:
(A) Applicable depreciable base for Polk; account 342.81
(B) Line 6 x 8.8238% x 1/12. Based on ROE of 11.75% and weighted income tax rate of 38.575% (expansion factor of 1.628002).
(C) Applicable depreciation rate is 3.4%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

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DOCKET NO. 090007-EI
ECRC 2008 FINAL 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 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	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 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		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
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)		27,049	26,633	26,692	26,368	26,398	26,828	26,619	26,476	26,498	26,623	26,646	26,823	319,653
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)		$27,049	$26,633	$26,692	$26,368	$26,398	$26,828	$26,619	$26,476	$26,498	$26,623	$26,646	$26,823	$319,653

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 Final True-Up Amount for the Period
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	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 Total
1.	Investments														
	a. Expenditures/Additions		$437	$346	$417	($1,176)	($28)	$0	$0	$0	$0	$0	$0	$0	($4)
	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	$1,649,121	$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	$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	367,771	368,208	368,554	368,971	367,795	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	
5.	Net Investment (Lines 2 + 3 + 4)	$1,964,727	1,960,629	1,956,440	1,952,322	1,946,611	1,942,048	1,937,513	1,932,978	1,928,443	1,923,908	1,919,373	1,914,838	1,910,303	
6.	Average Net Investment		1,962,678	1,958,535	1,954,381	1,949,467	1,944,330	1,939,781	1,935,246	1,930,711	1,926,176	1,921,641	1,917,106	1,912,571	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		14,432	14,401	14,371	14,335	14,297	14,264	14,230	14,197	14,163	14,130	14,097	14,063	$170,980
	b. Debt Component (Line 6 x 2.82% x 1/12)		4,612	4,603	4,593	4,581	4,569	4,558	4,548	4,537	4,527	4,516	4,505	4,495	54,644
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)		23,579	23,539	23,499	23,451	23,401	23,357	23,313	23,269	23,225	23,181	23,137	23,093	280,044
	a. Recoverable Costs Allocated to Energy		23,579	23,539	23,499	23,451	23,401	23,357	23,313	23,269	23,225	23,181	23,137	23,093	280,044
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
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)		22,820	22,472	22,524	22,244	22,262	22,622	22,444	22,321	22,338	22,441	22,458	22,605	269,551
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)		$22,820	$22,472	$22,524	$22,244	$22,262	$22,622	$22,444	$22,321	$22,338	$22,441	$22,458	$22,605	$269,551

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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DOCKET NO. 090007-EI
ECRC 2008 FINAL TRUE-UP
EXHIBIT HTB-1, DOC. NO. 8, PAGE 17 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
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	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 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)	$1,581,887	$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		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
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)		18,350	18,063	18,097	17,871	17,887	18,172	18,025	17,922	17,931	18,010	18,019	18,134	216,481
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)		$18,350	$18,063	$18,097	$17,871	$17,887	$18,172	$18,025	$17,922	$17,931	$18,010	$18,019	$18,134	$216,481

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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DOCKET NO. 090007-EI
ECRC 2008 FINAL TRUE-UP
EXHIBIT HTB-1, DOC. NO. 8, PAGE 18 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
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	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 Total
1.	Investments														
	a. Expenditures/Additions		$432,404	$74,612	$62,487	$35,386	$14,020	($77,358)	$77,381	$1,410	$83	$207	$0	$0	$620,632
	b. Clearings to Plant		0	0	0	2,737,764	14,020	(77,358)	77,381	1,410	83	207	0	0	2,753,507
	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	$2,737,764	$2,751,784	$2,674,426	$2,751,807	$2,753,217	$2,753,300	$2,753,507	$2,753,507	$2,753,507	
3.	Less: Accumulated Depreciation	0	0	0	0	(2,936)	(8,824)	(14,643)	(20,462)	(26,367)	(32,273)	(38,180)	(44,087)	(49,994)	
4.	CWIP - Non-Interest Bearing	2,132,875	2,565,279	2,639,891	2,702,378	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,132,875	2,565,279	2,639,891	2,702,378	2,734,828	2,742,960	2,659,783	2,731,345	2,726,850	2,721,027	2,715,327	2,709,420	2,703,513	
6.	Average Net Investment		2,349,077	2,602,585	2,671,135	2,718,603	2,738,894	2,701,372	2,695,564	2,729,098	2,723,939	2,718,177	2,712,374	2,706,467	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		17,273	19,137	19,641	19,990	20,140	19,864	19,821	20,068	20,030	19,987	19,945	19,901	$235,797
	b. Debt Component (Line 6 x 2.82% x 1/12)		5,520	6,116	6,277	6,389	6,436	6,348	6,335	6,413	6,401	6,388	6,374	6,360	75,357
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	2,936	5,888	5,819	5,819	5,905	5,906	5,907	5,907	5,907	49,994
	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)		22,793	25,253	25,918	29,315	32,464	32,031	31,975	32,386	32,337	32,282	32,226	32,168	361,148
	a. Recoverable Costs Allocated to Energy		22,793	25,253	25,918	29,315	32,464	32,031	31,975	32,386	32,337	32,282	32,226	32,168	361,148
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
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)		22,060	24,108	24,842	27,806	30,883	31,023	30,783	31,067	31,101	31,251	31,281	31,488	347,693
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)		$22,060	$24,108	$24,842	$27,806	$30,883	$31,023	$30,783	$31,067	$31,101	$31,251	$31,281	$31,488	$347,693

Notes:
(A) Applicable depreciable base for Big Bend; account 312.43 ($2,042,677) 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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DOCKET NO. 090007-EI
ECRC 2008 FINAL 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 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	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 Total
1.	Investments														
	a. Expenditures/Additions		$1,561,868	$566,544	$1,051,233	$1,230,140	$1,286,971	$657,362	$846,453	$924,340	$781,293	$2,017,391	$1,079,681	$2,077,772	$14,081,048
	b. Clearings to Plant		0	0	0	0	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)	$21,559,050	$23,120,918	$23,687,462	$24,738,695	$25,968,835	$27,255,806	$27,913,168	$28,759,621	$29,683,961	$30,465,254	$32,482,645	$33,562,326	$35,640,098	
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)	$21,559,050	23,120,918	23,687,462	24,738,695	25,968,835	27,255,806	27,913,168	28,759,621	29,683,961	30,465,254	32,482,645	33,562,326	35,640,098	
6.	Average Net Investment		22,339,984	23,404,190	24,213,079	25,353,765	26,612,321	27,584,487	28,336,395	29,221,791	30,074,608	31,473,950	33,022,486	34,601,212	
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		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
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 Final True-Up Amount for the Period
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	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 Total
1.	Investments														
	a. Expenditures/Additions		$1,667,980	$898,673	$4,497,280	$2,409,922	$4,698,872	$2,224,934	$3,046,170	$3,119,163	$3,648,204	$5,293,188	$4,909,859	$4,693,718	$41,107,963
	b. Clearings to Plant		0	0	0	0	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)	$29,055,383	$30,723,363	$31,622,036	$36,119,316	$38,529,238	$43,228,110	$45,453,044	$48,499,214	$51,618,377	$55,266,581	$60,559,769	$65,469,628	$70,163,346	
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)	$29,055,383	30,723,363	31,622,036	36,119,316	38,529,238	43,228,110	45,453,044	48,499,214	51,618,377	55,266,581	60,559,769	65,469,628	70,163,346	
6.	Average Net Investment		29,889,373	31,172,700	33,870,676	37,324,277	40,878,674	44,340,577	46,976,129	50,058,796	53,442,479	57,913,175	63,014,699	67,816,487	
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		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
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. 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 rates are 3.1%
(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.

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DOCKET NO. 090007-EI
ECRC 2008 FINAL TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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		$0	$0	$20,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$20,000
	b. Clearings to Plant		0	0	20,000	0	0	0	0	0	0	0	0	0	$20,000
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,153,186	$1,153,186	$1,153,186	$1,173,186	$1,173,186	$1,173,186	$1,173,186	$1,173,186	$1,173,186	$1,173,186	$1,173,186	$1,173,186	$1,173,186	
3.	Less: Accumulated Depreciation	(22,605)	(25,488)	(28,371)	(31,254)	(34,187)	(37,120)	(40,053)	(42,986)	(45,919)	(48,852)	(51,785)	(54,718)	(57,651)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,130,581	1,127,698	1,124,815	1,141,932	1,138,999	1,136,066	1,133,133	1,130,200	1,127,267	1,124,334	1,121,401	1,118,468	1,115,535	
6.	Average Net Investment		1,129,140	1,126,257	1,133,374	1,140,466	1,137,533	1,134,600	1,131,667	1,128,734	1,125,801	1,122,868	1,119,935	1,117,002	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		8,204	8,183	8,235	8,286	8,265	8,244	8,222	8,201	8,180	8,158	8,137	8,116	$98,431
	b. Debt Component Grossed Up For Taxes (F)		2,759	2,752	2,770	2,787	2,780	2,773	2,765	2,758	2,751	2,744	2,737	2,730	33,106
8.	Investment Expenses														
	a. Depreciation (C)		2,883	2,883	2,883	2,933	2,933	2,933	2,933	2,933	2,933	2,933	2,933	2,933	35,046
	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)		13,846	13,818	13,888	14,006	13,978	13,950	13,920	13,892	13,864	13,835	13,807	13,779	166,583
	a. Recoverable Costs Allocated to Energy		13,846	13,818	13,888	14,006	13,978	13,950	13,920	13,892	13,864	13,835	13,807	13,779	166,583
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		13,540	13,442	13,537	13,596	13,459	13,541	13,481	13,400	13,407	13,359	13,403	13,461	161,626
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)		$13,540	$13,442	$13,537	$13,596	$13,459	$13,541	$13,481	$13,400	$13,407	$13,359	$13,403	$13,461	$161,626

Notes:
(A) Applicable depreciable base for Big Bend and Polk; accounts 312.41, 312.43, 312.44, 315.40 ($1,173,186) and 345.81
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 3.3%, 2.6%, 2.4%, 3.0%, and 3.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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DOCKET NO. 090007-EI
ECRC 2010 PROJECTION FILING
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DOCUMENT NO. 4

Form 42-8A
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
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	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 Total
1.	Investments														
	a. Expenditures/Additions		$112,273	($49,818)	$103,703	$20,113	($236,669)	$18,261	$4,266	$493	$0	$0	$0	$0	($27,378)
	b. Clearings to Plant		112,273	(49,818)	103,703	20,113	(236,669)	18,261	4,266	493	0	0	0	0	(27,378)
	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)	$61,210,715	$61,322,988	$61,273,171	$61,376,874	$61,396,987	$61,160,318	$61,178,579	$61,182,845	$61,183,338	$61,183,338	$61,183,338	$61,183,338	$61,183,338	
3.	Less: Accumulated Depreciation	(913,640)	(1,036,174)	(1,158,770)	(1,281,420)	(1,404,194)	(1,526,751)	(1,649,090)	(1,771,451)	(1,893,817)	(2,016,184)	(2,138,551)	(2,260,918)	(2,383,285)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$60,297,075	60,286,814	60,114,401	60,095,454	59,992,793	59,633,567	59,529,489	59,411,394	59,289,521	59,167,154	59,044,787	58,922,420	58,800,053	
6.	Average Net Investment		60,291,945	60,200,608	60,104,928	60,044,124	59,813,180	59,581,528	59,470,442	59,350,458	59,228,338	59,105,971	58,983,604	58,861,237	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		443,337	442,665	441,962	441,514	439,816	438,113	437,296	436,414	435,516	434,616	433,716	432,816	$5,257,781
	b. Debt Component (Line 6 x 2.82% x 1/12)		141,686	141,471	141,247	141,104	140,561	140,017	139,756	139,474	139,187	138,899	138,611	138,324	1,680,337
8.	Investment Expenses														
	a. Depreciation (C)		122,534	122,596	122,650	122,774	122,557	122,339	122,361	122,366	122,367	122,367	122,367	122,367	1,469,645
	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)		707,557	706,732	705,859	705,392	702,934	700,469	699,413	698,254	697,070	695,882	694,694	693,507	8,407,763
	a. Recoverable Costs Allocated to Energy		707,557	706,732	705,859	705,392	702,934	700,469	699,413	698,254	697,070	695,882	694,694	693,507	8,407,763
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	-
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
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)		684,793	674,697	676,567	669,087	668,708	678,435	673,335	669,820	670,435	673,663	674,316	678,853	8,092,709
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)		$684,793	$674,697	$676,567	$669,087	$668,708	$678,435	$673,335	$669,820	$670,435	$673,663	$674,316	$678,853	$8,092,709

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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DOCKET NO. 090007-EI
ECRC 2008 FINAL TRUE-UP
EXHIBIT HTB-1, DOC. NO. 8, PAGE 23 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
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	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 Total
1.	Investments														
	a. Expenditures/Additions		$739,281	$292,814	$256,943	$85,317	$60,668	$27,303	$27,565	$14,775	$12,324	$4,525	($7,538)	$5,331	$1,519,307
	b. Clearings to Plant		0	0	0	6,418,273	60,603	$27,323	27,565	14,775	12,324	4,525	(7,538)	5,331	6,563,180
	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)	$5,001,604	$5,001,604	$5,001,604	$5,001,604	$11,419,877	$11,480,480	$11,507,803	$11,535,367	$11,550,141	$11,562,465	$11,566,990	$11,559,452	$11,564,783	
3.	Less: Accumulated Depreciation	(71,177)	(80,763)	(90,349)	(99,935)	(115,733)	(137,801)	(159,954)	(182,159)	(204,404)	(226,675)	(248,962)	(271,246)	(293,528)	
4.	CWIP - Non-Interest Bearing	5,060,055	5,799,336	6,092,150	6,349,093	16,137	16,202	16,182	16,182	16,182	16,182	16,182	16,182	16,182	
5.	Net Investment (Lines 2 + 3 + 4)	$9,990,482	10,720,177	11,003,405	11,250,762	11,320,281	11,358,881	11,364,031	11,369,390	11,361,919	11,351,972	11,334,210	11,304,388	11,287,437	
6.	Average Net Investment		10,355,330	10,861,791	11,127,084	11,285,522	11,339,581	11,361,456	11,366,711	11,365,655	11,356,946	11,343,091	11,319,299	11,295,912	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		76,144	79,869	81,819	82,984	83,382	83,543	83,581	83,574	83,510	83,408	83,233	83,061	$988,108
	b. Debt Component (Line 6 x 2.82% x 1/12)		24,335	25,525	26,149	26,521	26,648	26,699	26,712	26,709	26,689	26,656	26,600	26,545	315,788
8.	Investment Expenses														
	a. Depreciation (C)		9,586	9,586	9,586	15,798	22,068	22,153	22,205	22,245	22,271	22,287	22,284	22,282	222,351
	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)		110,065	114,980	117,554	125,303	132,098	132,395	132,498	132,528	132,470	132,351	132,117	131,888	1,526,247
	a. Recoverable Costs Allocated to Energy		110,065	114,980	117,554	125,303	132,098	132,395	132,498	132,528	132,470	132,351	132,117	131,888	1,526,247
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
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)		106,524	109,768	112,676	118,854	125,666	128,230	127,558	127,131	127,408	128,125	128,241	129,101	1,469,282
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)		$106,524	$109,768	$112,676	$118,854	$125,666	$128,230	$127,558	$127,131	$127,408	$128,125	$128,241	$129,101	$1,469,282

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44 ($1,456,209) and 312.45 ($10,108,574)
(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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DOCKET NO. 090007-EI
ECRC 2008 FINAL 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 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	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 Total
1.	Investments														
	a. Expenditures/Additions		$1,991	$344,698	$105,208	$4,944	$5,163	$964	$3,550	$3,045	$11,636	$2,804	$23,006	$310,952	$817,961
	b. Clearings to Plant		0	0	0	0	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	198,360	200,351	545,049	650,257	655,201	660,364	661,328	664,878	667,923	679,559	682,363	705,369	1,016,321	
5.	Net Investment (Lines 2 + 3 + 4)	$198,360	200,351	545,049	650,257	655,201	660,364	661,328	664,878	667,923	679,559	682,363	705,369	1,016,321	
6.	Average Net Investment		199,356	372,700	597,653	652,729	657,783	660,846	663,103	666,401	673,741	680,961	693,866	860,845	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		1,466	2,741	4,395	4,800	4,837	4,859	4,876	4,900	4,954	5,007	5,102	6,330	$54,267
	b. Debt Component (Line 6 x 2.82% x 1/12)		468	876	1,404	1,534	1,546	1,553	1,558	1,566	1,583	1,600	1,631	2,023	17,342
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)		1,934	3,617	5,799	6,334	6,383	6,412	6,434	6,466	6,537	6,607	6,733	8,353	71,609
	a. Recoverable Costs Allocated to Energy		1,934	3,617	5,799	6,334	6,383	6,412	6,434	6,466	6,537	6,607	6,733	8,353	71,609
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
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)		1,872	3,453	5,558	6,008	6,072	6,210	6,194	6,203	6,287	6,396	6,535	8,177	68,965
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)		$1,872	$3,453	$5,558	$6,008	$6,072	$6,210	$6,194	$6,203	$6,287	$6,396	$6,535	$8,177	$68,965

Notes:
(A) Applicable depreciable base for Big Bend and Polk; accounts 312.41, 312.43, 312.44, and 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%, and 3.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11

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ECRC 2008 FINAL 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 2008 to December 2008

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	Actual July	Actual August	Actual September	Actual October	Actual November	Actual 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		($1,250)	(12,500)	975,000	(2,500)	1,000,000	0	808,750	0	3,177,500	0	5,199,755	0	11,144,755
	c. Auction Proceeds/Other		0	0	0	0	0	0	638,084	0	0	0	0	0	638,084
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	(69,802)	(63,711)	(63,283)	(61,108)	(60,570)	(58,322)	(57,933)	(55,371)	(54,655)	(47,185)	(46,187)	(45,475)	(44,985)	
3.	Total Working Capital Balance	($69,802)	(63,711)	(63,283)	(61,108)	(60,570)	(58,322)	(57,933)	(55,371)	(54,655)	(47,185)	(46,187)	(45,475)	(44,985)	
4.	Average Net Working Capital Balance		($66,757)	($63,497)	($62,196)	($60,839)	($59,446)	($58,128)	($56,652)	($55,013)	($50,920)	($46,686)	($45,831)	($45,230)	
5.	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		(491)	(467)	(457)	(447)	(437)	(427)	(417)	(405)	(374)	(343)	(337)	(333)	(4,935)
	b. Debt Component (Line 4 x 2.82% x 1/12)		(157)	(149)	(146)	(143)	(140)	(137)	(133)	(129)	(120)	(110)	(108)	(106)	(1,578)
6.	Total Return Component		(648)	(616)	(603)	(590)	(577)	(564)	(550)	(534)	(494)	(453)	(445)	(439)	(6,513)
7.	Expenses:														
	a. Gains		1,250	12,500	(976,697)	2,500	(1,001,697)	0	(1,448,531)	0	(3,184,289)	0	(5,199,755)	0	(11,794,719)
	b. Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. SO_2 Allowance Expense		10,631	16,079	23,333	15,436	16,213	12,269	15,164	5,070	7,148	5,750	5,514	5,919	138,526
8.	Net Expenses (B)		11,881	28,579	(953,364)	17,936	(985,484)	12,269	(1,433,367)	5,070	(3,177,141)	5,750	(5,194,241)	5,919	(11,656,193)
9.	Total System Recoverable Expenses (Lines 6 + 8)		11,233	27,963	(953,967)	17,346	(986,061)	11,705	(1,433,917)	4,536	(3,177,635)	5,297	(5,194,686)	5,480	(11,662,706)
	a. Recoverable Costs Allocated to Energy		11,233	27,963	(953,967)	17,346	(986,061)	11,705	(1,433,917)	4,536	(3,177,635)	5,297	(5,194,686)	5,480	(11,662,706)
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9678275	0.9546721	0.9585015	0.9485322	0.9513098	0.9685443	0.9627142	0.9592781	0.9617904	0.9680708	0.9706658	0.9788701	
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)		10,872	26,695	(914,379)	16,453	(938,049)	11,337	(1,380,452)	4,351	(3,056,219)	5,128	(5,042,304)	5,364	(11,251,203)
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)		$10,872	$26,695	($914,379)	$16,453	($938,049)	$11,337	($1,380,452)	$4,351	($3,056,219)	$5,128	($5,042,304)	$5,364	($11,251,203)

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 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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DOCKET NO. 090007-EI
ECRC 2008 FINAL TRUE-UP
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DOCKET NO. 090007-EI
ECRC 2009 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2

INDEX

TAMPA ELECTRIC COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE

ACTUAL / ESTIMATED TRUE-UP AMOUNT
FOR THE PERIOD OF
JANUARY 2009 THROUGH DECEMBER 2009

FORMS 42-1E THROUGH 42-8E

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 29
COMPANY Tampa Electric Company (Direct)
WITNESS Howard T. Bryant (HTB-2)
DATE 11/02/09

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
January 2009 to December 2009
(in Dollars)

Form 42 - 1E

Line	Period Amount
1. Over/(Under) Recovery for the Current Period (Form 42-2E, Line 5)	($9,220,766)
2. Interest Provision (Form 42-2E, Line 6)	(58,363)
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 2010 to December 2010 (Lines 1 + 2 + 3)	($9,279,129)

Form 42 - 2E

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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)	$3,325,406	$3,271,914	$2,993,030	$3,046,026	$3,434,524	$3,783,674	$4,304,679	$4,280,633	$4,355,101	$3,923,160	$3,376,046	$3,416,039	$43,510,232
2.	True-Up Provision	392,598	392,598	392,598	392,598	392,598	392,598	392,598	392,598	392,598	392,598	392,598	392,603	4,711,171
3.	ECRC Revenues Applicable to Period (Lines 1 + 2)	3,718,004	3,664,512	3,385,628	3,438,624	3,827,122	4,176,272	4,697,277	4,673,231	4,747,699	4,315,758	3,768,644	3,808,642	48,221,413
4.	Jurisdictional ECRC Costs													
	a. O & M Activities (Form 42-5A, Line 9)	1,120,205	1,094,396	1,139,096	1,404,570	897,593	1,105,995	1,273,791	1,473,769	1,601,613	1,682,140	1,440,204	1,921,200	16,154,572
	b. Capital Investment Projects (Form 42-7A, Line 9)	3,103,129	3,099,629	3,106,967	3,093,907	3,079,351	3,073,427	3,011,812	3,438,025	4,067,426	4,053,227	4,069,135	4,091,572	41,287,607
	c. Total Jurisdictional ECRC Costs	4,223,334	4,194,025	4,246,063	4,498,477	3,976,944	4,179,422	4,285,603	4,911,794	5,669,039	5,735,367	5,509,339	6,012,772	57,442,179
5.	Over/Under Recovery (Line 3 - Line 4c)	(505,330)	(529,513)	(860,435)	(1,059,853)	(149,822)	(3,150)	411,674	(238,563)	(921,340)	(1,419,609)	(1,740,695)	(2,204,130)	(9,220,766)
6.	Interest Provision (Form 42-3A, Line 10)	(2,118)	(3,048)	(3,161)	(2,884)	(2,361)	(2,344)	(4,081)	(5,785)	(6,401)	(7,390)	(8,637)	(10,133)	(58,363)
7.	Beginning Balance True-Up & Interest Provision	4,711,171	3,811,125	2,885,966	1,629,772	174,437	(370,364)	(768,456)	(753,461)	(1,390,407)	(2,710,746)	(4,530,343)	(6,672,273)	4,711,171
	a. Deferred True-Up from January to December 2008 (Order No. PSC-xx-xxxx-FOF-EI)	(8,112,993)	(8,112,993)	(8,112,993)	(8,112,993)	(8,112,993)	(8,112,993)	(8,112,993)	(8,112,993)	(8,112,993)	(8,112,993)	(8,112,993)	(8,112,993)	(8,112,993)
8.	True-Up Collected/(Refunded) (see Line 2)	(392,598)	(392,598)	(392,598)	(392,598)	(392,598)	(392,598)	(392,598)	(392,598)	(392,598)	(392,598)	(392,598)	(392,603)	(4,711,181)
9.	End of Period Total True-Up (Lines 5+6+7+7a+8)	(4,301,868)	(5,227,027)	(6,483,221)	(7,938,556)	(8,483,357)	(8,881,449)	(8,866,454)	(9,503,400)	(10,823,739)	(12,643,336)	(14,785,266)	(17,392,132)	(17,392,132)
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)	($4,301,868)	($5,227,027)	($6,483,221)	($7,938,556)	($8,483,357)	($8,881,449)	($8,866,454)	($9,503,400)	($10,823,739)	($12,643,336)	($14,785,266)	($17,392,132)	($17,392,132)

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

Form 42 - 3E

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 42-2E, Line 7 + 7a + 10)	($3,401,822)	($4,301,868)	($5,227,027)	($6,483,221)	($7,938,556)	($8,483,357)	($8,881,449)	($8,866,454)	($9,503,400)	($10,823,739)	($12,643,336)	($14,785,266)	
2.	Ending True-Up Amount Before Interest	(4,299,750)	(5,223,979)	(6,480,060)	(7,935,672)	(8,480,976)	(8,879,105)	(8,862,373)	(9,497,615)	(10,817,338)	(12,635,946)	(14,776,629)	(17,381,999)	
3.	Total of Beginning & Ending True-Up (Lines 1 + 2)	(7,701,572)	(9,525,847)	(11,707,087)	(14,418,893)	(16,419,532)	(17,362,462)	(17,743,822)	(18,364,069)	(20,320,738)	(23,459,685)	(27,419,965)	(32,167,265)	
4.	Average True-Up Amount (Line 3 x 1/2)	(3,850,786)	(4,762,924)	(5,853,544)	(7,209,447)	(8,209,766)	(8,681,231)	(8,871,911)	(9,182,035)	(10,160,369)	(11,729,843)	(13,709,983)	(16,083,633)	
5.	Interest Rate (First Day of Reporting Business Month)	0.54%	0.79%	0.75%	0.55%	0.40%	0.30%	0.35%	0.75%	0.75%	0.75%	0.75%	0.75%	
6.	Interest Rate (First Day of Subsequent Business Month)	0.79%	0.75%	0.55%	0.40%	0.30%	0.35%	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%	
7.	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	1.33%	1.54%	1.30%	0.95%	0.70%	0.65%	1.10%	1.50%	1.50%	1.50%	1.50%	1.50%	
8.	Average Interest Rate (Line 7 x 1/2)	0.665%	0.770%	0.650%	0.475%	0.350%	0.325%	0.550%	0.750%	0.750%	0.750%	0.750%	0.750%	
9.	Monthly Average Interest Rate (Line 8 x 1/12)	0.055%	0.064%	0.054%	0.040%	0.029%	0.027%	0.046%	0.063%	0.063%	0.063%	0.063%	0.063%	
10.	Interest Provision for the Month (Line 4 x Line 9)	($2,118)	($3,048)	($3,161)	($2,884)	($2,381)	($2,344)	($4,081)	($5,785)	($6,401)	($7,390)	($8,637)	($10,133)	($58,363)

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

Form 42 - 4E

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	$3,351,790	$3,658,000	($306,210)	-8.4%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0.0%
	c. SO_2 Emissions Allowances	377,496	(12,123,542)	12,501,038	103.1%
	d. Big Bend Units 1 & 2 FGD	8,386,537	7,482,800	903,737	12.1%
	e. Big Bend PM Minimization and Monitoring	467,907	455,000	12,907	2.8%
	f. Big Bend NO_x Emissions Reduction	361,773	358,000	3,773	1.1%
	g. NPDES Annual Surveillance Fees	34,500	34,500	0	0.0%
	h. Gannon Thermal Discharge Study	194,066	50,000	144,066	288.1%
	i. Polk NO_x Emissions Reduction	49,036	75,000	(25,964)	-34.6%
	j. Bayside SCR Consumables	122,057	82,000	40,057	48.9%
	k. Big Bend Unit 4 SOFA	25,718	50,000	(24,282)	-48.6%
	l. Big Bend Unit 1 Pre-SCR	77,000	77,000	0	0.0%
	m. Big Bend Unit 2 Pre-SCR	67,722	77,000	(9,278)	-12.0%
	n. Big Bend Unit 3 Pre-SCR	0	0	0	0.0%
	o. Clean Water Act Section 316(b) Phase II Study	47,240	150,000	(102,760)	-68.5%
	p. Arsenic Groundwater Standard Program	115,846	114,000	1,846	1.6%
	q. Big Bend 2 SCR	728,900	1,807,700	(1,078,800)	-59.7%
	r. Big Bend 3 SCR	1,437,288	2,204,900	(767,612)	-34.8%
	s. Big Bend 4 SCR	678,922	1,252,800	(573,878)	-45.8%
	t. Clean Air Mercury Rule	16,255	0	16,255	N/A
2.	Total Investment Projects - Recoverable Costs	$16,540,053	$5,805,158	$10,734,895	-184.9%
3.	Recoverable Costs Allocated to Energy	$16,148,401	$5,456,658	$10,691,743	-195.9%
4.	Recoverable Costs Allocated to Demand	$391,652	$348,500	$43,152	12.4%

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-08-0775-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 2009 to December 2009

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 Desulfurization Integration	$251,805	$212,491	$232,543	$302,316	$285,328	$212,406	$240,700	$270,000	$401,300	$406,200	$252,000	$284,700	$3,351,790		$3,351,790
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	6,808	2,253	1,952	1,311	(91,654)	1,005	79,253	79,178	76,550	72,470	71,241	77,129	377,496		377,496
d.	Big Bend Units 1 & 2 FGD (Less Gypsum Revenue)	641,230	556,730	621,191	798,241	514,842	674,204	573,100	676,900	761,500	779,800	658,300	1,128,500	8,386,537		8,386,537
e.	Big Bend PM Minimization and Monitoring	40,867	71,601	21,126	28,445	18,636	48,831	36,400	36,400	35,700	44,200	41,500	44,200	467,907		467,907
f.	Big Bend NO_x Emissions Reduction	28,343	89,687	50,001	7,874	9,568	15,700	20,900	20,900	20,200	25,300	27,200	46,100	361,773		361,773
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	0	19,115	62,481	0	12,469	60,000	30,000	0	0	10,000	0	194,066	194,066	
i.	Polk NO_x Reduction	2,334	740	1,054	17,310	1,995	4,603	3,500	3,500	3,500	3,500	3,500	3,500	49,036		49,036
j.	Bayside SCR and Ammonia	0	22,768	23,834	0	7,398	8,057	10,001	9,999	9,997	10,002	10,001	10,001	122,057		122,057
k.	Big Bend Unit 4 SOFA	0	0	0	(24,282)	0	0	0	0	0	14,300	35,700	0	25,718		25,718
l.	Big Bend Unit 1 Pre-SCR	0	0	0	0	0	0	0	0	0	0	6,900	70,100	77,000		77,000
m.	Big Bend Unit 2 Pre-SCR	16,541	48,806	950	0	0	1,425	0	0	0	0	0	0	67,722		67,722
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	1,874	0	0	8,872	2,494	0	12,000	12,000	0	0	12,000	0	47,240	47,240	
p.	Arsenic Groundwater Standard Program	0	0	3,823	48,905	3,716	19,902	10,000	0	0	29,500	0	0	115,846	115,846	
q.	Big Bend 2 SCR	0	0	0	0	0	0	0	157,600	153,400	153,700	145,300	118,900	728,900		728,900
r.	Big Bend 3 SCR	74,326	70,010	111,528	102,378	103,782	81,164	186,700	158,000	124,000	154,300	146,000	125,100	1,437,268		1,437,268
s.	Big Bend 4 SCR	34,936	31,205	60,962	70,283	53,751	42,084	81,500	70,000	68,300	47,600	62,300	56,000	678,922		678,922
t.	Clean Air Mercury Rule	0	0	0	0	550	705	2,500	2,500	2,500	2,500	2,500	2,500	16,255		16,255
2.	Total of O&M Activities	1,133,565	1,106,291	1,148,079	1,422,136	910,406	1,122,554	1,316,554	1,528,977	1,656,947	1,743,372	1,484,442	1,966,730	16,540,053	$ 391,652	$ 16,148,400
3.	Recoverable Costs Allocated to Energy	1,097,191	1,106,291	1,125,141	1,303,878	904,196	1,090,182	1,234,554	1,486,977	1,656,947	1,713,872	1,462,442	1,966,730	16,148,401		
4.	Recoverable Costs Allocated to Demand	36,374	0	22,938	118,258	6,210	32,372	82,000	42,000	0	29,500	22,000	0	391,652		
5.	Retail Energy Jurisdictional Factor	0.9891913	0.9892481	0.9926581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9668046	0.9649832	0.9703716	0.9768498			
6.	Retail Demand Jurisdictional Factor	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232			
7.	Jurisdictional Energy Recoverable Costs (A)	1,085,332	1,094,396	1,117,105	1,291,193	891,639	1,074,959	1,195,176	1,433,503	1,601,613	1,653,856	1,419,112	1,921,200	15,779,086		
8.	Jurisdictional Demand Recoverable Costs (B)	34,873	0	21,991	113,377	5,954	31,036	78,615	40,266	0	28,282	21,092	0	375,486		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,120,205	$1,094,396	$1,139,096	$1,404,570	$897,593	$1,105,995	$1,273,791	$1,473,769	$1,601,613	$1,682,140	$1,440,204	$1,921,200	$16,154,572		

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

DOCKET NO. 090007-EI
ECRC 2009 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 5, PAGE 1 OF 1

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

Form 42 - 6E

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	$786,289	$786,042	$247	0.0%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	440,808	440,693	115	0.0%
	c. Big Bend Unit 4 Continuous Emissions Monitors	80,611	80,584	27	0.0%
	d. Big Bend Fuel Oil Tank # 1 Upgrade	54,575	54,560	15	0.0%
	e. Big Bend Fuel Oil Tank # 2 Upgrade	89,767	89,738	29	0.0%
	f. Phillips Upgrade Tank # 1 for FDEP	5,862	5,859	3	0.1%
	g. Phillips Upgrade Tank # 4 for FDEP	9,215	9,211	4	0.0%
	h. Big Bend Unit 1 Classifier Replacement	138,835	138,796	39	0.0%
	i. Big Bend Unit 2 Classifier Replacement	100,518	100,489	29	0.0%
	j. Big Bend Section 114 Mercury Testing Platform	13,584	13,577	7	0.1%
	k. Big Bend Units 1 & 2 FGD	8,921,117	8,960,005	(38,888)	-0.4%
	l. Big Bend FGD Optimization and Utilization	2,533,290	2,532,454	836	0.0%
	m. Big Bend NO_x Emissions Reduction	802,153	793,965	8,188	1.0%
	n. Big Bend PM Minimization and Monitoring	1,086,037	1,124,629	(38,592)	-3.4%
	o. Polk NO_x Emissions Reduction	201,759	201,701	58	0.0%
	p. Big Bend Unit 4 SOFA	325,057	324,949	108	0.0%
	q. Big Bend Unit 1 Pre-SCR	273,776	279,459	(5,683)	-2.0%
	r. Big Bend Unit 2 Pre-SCR	219,267	219,196	71	0.0%
	s. Big Bend Unit 3 Pre-SCR	378,117	370,508	7,609	2.1%
	t. Big Bend Unit 1 SCR	0	0	0	0.0%
	u. Big Bend Unit 2 SCR	4,884,018	8,618,125	(3,734,107)	-43.3%
	v. Big Bend Unit 3 SCR	10,944,895	11,145,102	(200,207)	-1.8%
	w. Big Bend Unit 4 SCR	8,232,257	8,232,074	183	0.0%
	x. Big Bend FGD System Reliability	1,566,595	1,587,494	(20,899)	-1.3%
	y. Clean Air Mercury Rule	151,020	110,652	40,368	36.5%
	z. SO_2 Emissions Allowances	(5,037)	(1,669)	(3,368)	-201.8%
2.	Total Investment Projects - Recoverable Costs	$42,234,385	$46,218,193	($3,983,808)	-8.6%
3.	Recoverable Costs Allocated to Energy	$42,074,966	$46,058,825	($3,983,859)	-8.6%
4.	Recoverable Costs Allocated to Demand	$159,419	$159,368	$51	0.0%

Notes:
Column (1) is the End of Period Totals on Form 42-7E.
Column (2) is the approved projected amount in accordance with FPSC Order No. PSC-08-0775-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 2009 to December 2009

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	$66,346	$66,193	$66,040	$65,887	$65,759	$65,612	$65,459	$65,305	$65,152	$64,998	$64,846	$64,692	$786,289		$786,289
b.	Big Bend Units 1 and 2 Flue Gas Conditioning	37,440	37,310	37,180	37,050	36,931	36,804	36,674	36,544	36,414	36,284	36,153	36,024	440,808		440,808
c.	Big Bend Unit 4 Continuous Emissions Monitors	6,796	6,781	6,767	6,752	6,740	6,726	6,712	6,697	6,682	6,667	6,653	6,638	80,611		80,611
d.	Big Bend Fuel Oil Tank #1 Upgrade	4,604	4,593	4,583	4,572	4,564	4,554	4,543	4,534	4,523	4,512	4,502	4,491	54,575	$ 54,575	
e.	Big Bend Fuel Oil Tank #2 Upgrade	7,573	7,555	7,538	7,521	7,508	7,490	7,474	7,456	7,439	7,422	7,404	7,387	89,767	89,767	
f.	Phillips Upgrade Tank #1 for FDEP	497	495	493	491	491	489	488	486	485	484	482	481	5,862	5,862	
g.	Phillips Upgrade Tank #4 for FDEP	780	778	775	773	772	769	767	765	762	760	758	756	9,215	9,215	
h.	Big Bend Unit 1 Classifier Replacement	11,759	11,725	11,689	11,654	11,623	11,589	11,554	11,519	11,483	11,448	11,413	11,379	138,835		138,835
i.	Big Bend Unit 2 Classifier Replacement	8,510	8,485	8,461	8,436	8,415	8,390	8,365	8,341	8,316	8,291	8,266	8,242	100,518		100,518
j.	Big Bend Section 114 Mercury Testing Platform	1,142	1,140	1,138	1,137	1,136	1,133	1,131	1,129	1,127	1,126	1,123	1,122	13,584		13,584
k.	Big Bend Units 1 & 2 FGD (Less Gypsum Revenue)	750,756	749,929	748,929	747,696	746,208	744,372	742,761	741,002	739,140	737,340	736,225	736,759	8,921,117		8,921,117
l.	Big Bend FGD Optimization and Utilization	213,260	212,856	212,452	212,048	211,731	211,348	210,943	210,539	210,135	209,731	209,326	208,921	2,533,290		2,533,290
m.	Big Bend NO_x Emissions Reduction	66,999	66,927	66,854	66,780	66,737	66,667	66,589	66,523	66,459	66,720	67,335	67,563	802,153		802,153
n.	Big Bend PM Minimization and Monitoring	89,766	90,356	90,910	90,901	90,897	90,769	90,734	90,715	90,551	90,349	90,146	89,943	1,086,037		1,086,037
o.	Polk NO_x Emissions Reduction	17,045	17,001	16,959	16,915	16,879	16,837	16,794	16,752	16,709	16,666	16,623	16,579	201,759		201,759
p.	Big Bend Unit 4 SOFA	27,352	27,302	27,253	27,203	27,165	27,118	27,068	27,018	26,969	26,919	26,870	26,820	325,057		325,057
q.	Big Bend Unit 1 Pre-SCR	23,049	23,005	22,961	22,917	22,883	22,840	22,796	22,753	22,709	22,665	22,621	22,577	273,776		273,776
r.	Big Bend Unit 2 Pre-SCR	18,485	18,445	18,406	18,365	18,332	18,295	18,256	18,216	18,176	18,137	18,097	18,057	219,267		219,267
s.	Big Bend Unit 3 Pre-SCR	32,111	32,053	31,997	31,939	31,895	31,613	31,226	31,170	31,113	31,056	31,000	30,944	378,117		378,117
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	460,859	1,108,527	1,106,876	1,104,598	1,103,358	4,884,018		4,884,018
v.	Big Bend Unit 3 SCR	919,651	918,474	917,164	915,710	914,741	913,439	911,669	910,050	908,429	906,809	905,189	903,570	10,944,895		10,944,895
w.	Big Bend Unit 4 SCR	692,320	691,133	689,945	688,758	687,860	686,742	685,554	684,365	683,177	681,989	680,801	679,613	8,232,257		8,232,257
x.	Big Bend FGD System Reliability	131,693	131,463	131,251	131,042	130,888	130,685	130,470	130,253	130,037	129,821	129,604	129,388	1,566,595		1,566,595
y.	Clean Air Mercury Rule	9,951	10,166	10,463	10,611	13,362	13,462	13,567	13,774	13,958	13,930	13,902	13,874	151,020		151,020
z.	SO_2 Emissions Allowances (B)	(435)	(433)	(431)	(430)	(428)	(425)	(422)	(417)	(412)	(406)	(401)	(397)	(5,037)		(5,037)
2.	Total Investment Projects - Recoverable Costs	3,137,450	3,133,732	3,129,777	3,124,728	3,123,089	3,117,318	3,111,172	3,566,348	4,208,060	4,200,394	4,193,536	4,188,781	42,234,385	$ 159,419	$ 42,074,966
3.	Recoverable Costs Allocated to Energy	3,123,996	3,120,311	3,116,388	3,111,371	3,109,754	3,104,016	3,097,900	3,553,107	4,194,851	4,187,216	4,180,390	4,175,666	42,074,966		
4.	Recoverable Costs Allocated to Demand	13,454	13,421	13,389	13,357	13,335	13,302	13,272	13,241	13,209	13,178	13,146	13,115	159,419		
5.	Retail Energy Jurisdictional Factor	0.9891913	0.9892481	0.9926581	0.9902713	0.9861120	0.9860367	0.9681038	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498			
6.	Retail Demand Jurisdictional Factor	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232			
7.	Jurisdictional Energy Recoverable Costs (C)	3,090,230	3,086,762	3,094,131	3,081,101	3,066,566	3,060,674	2,999,088	3,425,331	4,054,762	4,040,593	4,056,532	4,078,998	41,134,768		
8.	Jurisdictional Demand Recoverable Costs (D)	12,899	12,867	12,836	12,806	12,785	12,753	12,724	12,694	12,664	12,634	12,603	12,574	152,839		
9.	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$3,103,129	$3,099,629	$3,106,967	$3,093,907	$3,079,351	$3,073,427	$3,011,812	$3,438,025	$4,067,426	$4,053,227	$4,069,135	$4,091,572	$41,287,607		

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. 090007-EI
ECRC 2009 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 7, PAGE 1 OF 1

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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	(3,021,777)	(3,037,570)	(3,053,363)	(3,069,156)	(3,084,949)	(3,100,742)	(3,116,535)	(3,132,328)	(3,148,121)	(3,163,914)	(3,179,707)	(3,195,500)	(3,211,293)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$5,217,881	5,202,088	5,186,295	5,170,502	5,154,709	5,138,916	5,123,123	5,107,330	5,091,537	5,075,744	5,059,951	5,044,158	5,028,365	
6.	Average Net Investment		5,209,985	5,194,192	5,178,399	5,162,606	5,146,813	5,131,020	5,115,227	5,099,434	5,083,641	5,067,848	5,052,055	5,036,262	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		38,310	38,194	38,078	37,962	37,482	37,280	37,166	37,051	36,936	36,821	36,707	36,592	$448,579
	b. Debt Component Grossed Up For Taxes (F)		12,243	12,206	12,169	12,132	12,484	12,539	12,500	12,461	12,423	12,384	12,346	12,307	148,194
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)		66,346	66,193	66,040	65,887	65,759	65,612	65,459	65,305	65,152	64,998	64,846	64,692	786,289
	a. Recoverable Costs Allocated to Energy		66,346	66,193	66,040	65,887	65,759	65,612	65,459	65,305	65,152	64,998	64,846	64,692	786,289
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649632	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		65,629	65,481	65,568	65,246	64,846	64,696	63,371	62,957	62,976	62,722	62,925	63,194	769,611
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)		$65,629	$65,481	$65,568	$65,246	$64,846	$64,696	$63,371	$62,957	$62,976	$62,722	$62,925	$63,194	$769,611

Notes:

(A) Applicable depreciable base for Big Bend; account 312.45 ($8,239,658)
(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). Effective May 7, 2009, Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 2.3%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

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DOCKET NO. 080007-EI
ECRC 2008 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 8, PAGE 1 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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	(2,534,402)	(2,547,811)	(2,561,220)	(2,574,629)	(2,588,038)	(2,601,447)	(2,614,856)	(2,628,265)	(2,641,674)	(2,655,083)	(2,668,492)	(2,681,901)	(2,695,310)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,483,332	2,469,923	2,456,514	2,443,105	2,429,696	2,416,287	2,402,878	2,389,469	2,376,060	2,362,651	2,349,242	2,335,833	2,322,424	
6.	Average Net Investment		2,476,628	2,463,219	2,449,810	2,436,401	2,422,992	2,409,583	2,396,174	2,382,765	2,369,356	2,355,947	2,342,538	2,329,129	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		18,211	18,112	18,014	17,915	17,645	17,507	17,410	17,312	17,215	17,118	17,020	16,923	$210,402
	b. Debt Component Grossed Up For Taxes (F)		5,820	5,789	5,757	5,726	5,877	5,888	5,855	5,823	5,790	5,757	5,724	5,692	69,498
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)		37,440	37,310	37,180	37,050	36,931	36,804	36,674	36,544	36,414	36,284	36,153	36,024	440,808
	a. Recoverable Costs Allocated to Energy		37,440	37,310	37,180	37,050	36,931	36,804	36,674	36,544	36,414	36,284	36,153	36,024	440,808
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		37,035	36,909	36,914	36,690	36,418	36,290	35,504	35,230	35,198	35,013	35,082	35,190	431,473
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)		$37,035	$36,909	$36,914	$36,690	$36,418	$36,290	$35,504	$35,230	$35,198	$35,013	$35,082	$35,190	$431,473

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). Effective May 7, 2009, Line 4 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of
(C) Applicable depreciation rates are 3.3% and 3.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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	(321,269)	(322,785)	(324,301)	(325,817)	(327,333)	(328,849)	(330,365)	(331,881)	(333,397)	(334,913)	(336,429)	(337,945)	(339,461)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$544,942	543,426	541,910	540,394	538,878	537,362	535,846	534,330	532,814	531,298	529,782	528,266	526,750	
6.	Average Net Investment		544,184	542,668	541,152	539,636	538,120	536,604	535,088	533,572	532,056	530,540	529,024	527,508	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,001	3,990	3,979	3,968	3,919	3,899	3,888	3,877	3,866	3,855	3,844	3,833	$46,919
	b. Debt Component Grossed Up For Taxes (F)		1,279	1,275	1,272	1,268	1,305	1,311	1,308	1,304	1,300	1,296	1,293	1,289	15,500
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)		6,796	6,781	6,767	6,752	6,740	6,726	6,712	6,697	6,682	6,667	6,653	6,638	80,611
	a. Recoverable Costs Allocated to Energy		6,796	6,781	6,767	6,752	6,740	6,726	6,712	6,697	6,682	6,667	6,653	6,638	80,611
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		6,723	6,708	6,719	6,686	6,646	6,632	6,498	6,456	6,459	6,434	6,456	6,484	78,901
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)		$6,723	$6,708	$6,719	$6,686	$6,646	$6,632	$6,498	$6,456	$6,459	$6,434	$6,456	$6,484	$78,901

Notes:
(A) Applicable depreciable base for Big Bend; account 315.44 ($866,211)
(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). Effective May 7, 2009, Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 2.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

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DOCKET NO. 080007-EI
ECRC 2008 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 8, PAGE 3 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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	(133,624)	(134,702)	(135,780)	(136,858)	(137,936)	(139,014)	(140,092)	(141,170)	(142,248)	(143,326)	(144,404)	(145,482)	(146,560)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$363,954	362,876	361,798	360,720	359,642	358,564	357,486	356,408	355,330	354,252	353,174	352,096	351,018	
6.	Average Net Investment		363,415	362,337	361,259	360,181	359,103	358,025	356,947	355,869	354,791	353,713	352,635	351,557	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		2,672	2,664	2,656	2,648	2,615	2,601	2,593	2,586	2,578	2,570	2,562	2,554	$31,299
	b. Debt Component Grossed Up For Taxes (F)		854	851	849	846	871	875	872	870	867	864	862	859	10,340
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)		4,604	4,593	4,583	4,572	4,564	4,554	4,543	4,534	4,523	4,512	4,502	4,491	54,575
	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		4,604	4,593	4,583	4,572	4,564	4,554	4,543	4,534	4,523	4,512	4,502	4,491	54,575
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
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)		4,414	4,403	4,394	4,383	4,376	4,366	4,355	4,347	4,336	4,326	4,316	4,306	52,322
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,414	$4,403	$4,394	$4,383	$4,376	$4,366	$4,355	$4,347	$4,336	$4,326	$4,316	$4,306	$52,322

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40 ($497,578)
(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). Effective May 7, 2009, Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 2.6%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

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DOCKET NO. 080007-EI
ECRC 2008 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 8, PAGE 4 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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	(219,796)	(221,569)	(223,342)	(225,115)	(226,888)	(228,661)	(230,434)	(232,207)	(233,980)	(235,753)	(237,526)	(239,299)	(241,072)	
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)	$598,605	596,832	595,059	593,286	591,513	589,740	587,967	586,194	584,421	582,648	580,875	579,102	577,329	
6.	Average Net Investment		597,719	595,946	594,173	592,400	590,627	588,854	587,081	585,308	583,535	581,762	579,989	578,216	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,395	4,382	4,369	4,356	4,302	4,278	4,266	4,253	4,240	4,227	4,214	4,201	$51,483
	b. Debt Component Grossed Up For Taxes (F)		1,405	1,400	1,396	1,392	1,433	1,439	1,435	1,430	1,426	1,422	1,417	1,413	17,008
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)		7,573	7,555	7,538	7,521	7,508	7,490	7,474	7,456	7,439	7,422	7,404	7,387	89,767
	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		7,573	7,555	7,538	7,521	7,508	7,490	7,474	7,456	7,439	7,422	7,404	7,387	89,767
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
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)		7,260	7,243	7,227	7,211	7,198	7,181	7,165	7,148	7,132	7,116	7,098	7,082	86,061
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$7,260	$7,243	$7,227	$7,211	$7,198	$7,181	$7,165	$7,148	$7,132	$7,116	$7,098	$7,082	$86,061

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40 ($818,401)
(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). Effective May 7, 2009, Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 2.6%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

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ECRC 2008 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 2009 to December 2009

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	(20,820)	(20,963)	(21,106)	(21,249)	(21,392)	(21,535)	(21,678)	(21,821)	(21,964)	(22,107)	(22,250)	(22,393)	(22,536)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$36,457	36,314	36,171	36,028	35,885	35,742	35,599	35,456	35,313	35,170	35,027	34,884	34,741	
6.	Average Net Investment		36,386	36,243	36,100	35,957	35,814	35,671	35,528	35,385	35,242	35,099	34,956	34,813	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		268	267	265	264	261	259	258	257	256	255	254	253	$3,117
	b. Debt Component Grossed Up For Taxes (F)		86	85	85	84	87	87	87	86	86	86	85	85	1,029
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)		497	495	493	491	491	489	488	486	485	484	482	481	5,862
	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		497	495	493	491	491	489	488	486	485	484	482	481	5,862
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
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)		476	475	473	471	471	469	468	466	465	464	462	461	5,621
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$476	$475	$473	$471	$471	$469	$468	$466	$465	$464	$462	$461	$5,621

Notes:
(A) Applicable depreciable base for Phillips; account 342.28 ($57,277)
(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). Effective May 7, 2009, Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 3.0%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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	(33,299)	(33,525)	(33,751)	(33,977)	(34,203)	(34,429)	(34,655)	(34,881)	(35,107)	(35,333)	(35,559)	(35,785)	(36,011)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$57,173	56,947	56,721	56,495	56,269	56,043	55,817	55,591	55,365	55,139	54,913	54,687	54,461	
6.	Average Net Investment		57,060	56,834	56,608	56,382	56,156	55,930	55,704	55,478	55,252	55,026	54,800	54,574	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		420	418	416	415	409	406	405	403	401	400	398	397	$4,888
	b. Debt Component Grossed Up For Taxes (F)		134	134	133	132	137	137	136	136	135	134	134	133	1,615
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)		780	778	775	773	772	769	767	765	762	760	758	756	9,215
	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		780	778	775	773	772	769	767	765	762	760	758	756	9,215
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
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)		748	746	743	741	740	737	735	733	731	729	727	725	8,835
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$748	$746	$743	$741	$740	$737	$735	$733	$731	$729	$727	$725	$8,835

Notes:

(A) Applicable depreciable base for Phillips; account 342.28 ($90,472)
(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). Effective May 7, 2009, Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 3.0%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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	(475,592)	(479,212)	(482,832)	(486,452)	(490,072)	(493,692)	(497,312)	(500,932)	(504,552)	(508,172)	(511,792)	(515,412)	(519,032)	
4.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$840,665	837,045	833,425	829,805	826,185	822,565	818,945	815,325	811,705	808,085	804,465	800,845	797,225	
6.	Average Net Investment		838,855	835,235	831,615	827,995	824,375	820,755	817,135	813,515	809,895	806,275	802,655	799,035	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		6,168	6,142	6,115	6,088	6,003	5,963	5,937	5,911	5,884	5,858	5,832	5,806	$71,707
	b. Debt Component Grossed Up For Taxes (F)		1,971	1,963	1,954	1,946	2,000	2,006	1,997	1,988	1,979	1,970	1,961	1,953	23,688
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)		11,759	11,725	11,689	11,654	11,623	11,589	11,554	11,519	11,483	11,448	11,413	11,379	138,835
	a. Recoverable Costs Allocated to Energy		11,759	11,725	11,689	11,654	11,623	11,589	11,554	11,519	11,483	11,448	11,413	11,379	138,835
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		11,632	11,599	11,606	11,541	11,462	11,427	11,185	11,105	11,100	11,047	11,075	11,116	135,895
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)		$11,632	$11,599	$11,606	$11,541	$11,462	$11,427	$11,185	$11,105	$11,100	$11,047	$11,075	$11,116	$135,895

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41 ($1,316,257)
(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). Effective May 7, 2009, Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax ra 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 3.3%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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	(368,694)	(371,238)	(373,782)	(376,326)	(378,870)	(381,414)	(383,958)	(386,502)	(389,046)	(391,590)	(394,134)	(396,678)	(399,222)	
4.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$616,100	613,556	611,012	608,468	605,924	603,380	600,836	598,292	595,748	593,204	590,660	588,116	585,572	
6.	Average Net Investment		614,828	612,284	609,740	607,196	604,652	602,108	599,564	597,020	594,476	591,932	589,388	586,844	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,521	4,502	4,484	4,465	4,404	4,375	4,356	4,338	4,319	4,301	4,282	4,264	$52,611
	b. Debt Component Grossed Up For Taxes (F)		1,445	1,439	1,433	1,427	1,467	1,471	1,465	1,459	1,453	1,446	1,440	1,434	17,379
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)		8,510	8,485	8,461	8,436	8,415	8,390	8,365	8,341	8,316	8,291	8,266	8,242	100,518
	a. Recoverable Costs Allocated to Energy		8,510	8,485	8,461	8,436	8,415	8,390	8,365	8,341	8,316	8,291	8,266	8,242	100,518
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		8,418	8,394	8,401	8,354	8,298	8,273	8,098	8,041	8,038	8,001	8,021	8,051	98,388
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)		$8,418	$8,394	$8,401	$8,354	$8,298	$8,273	$8,098	$8,041	$8,038	$8,001	$8,021	$8,051	$98,388

Notes:

(A) Applicable depreciable base for Big Bend; account 312.42 ($984,794)
(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). Effective May 7, 2009, Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 3.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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	(23,647)	(23,848)	(24,049)	(24,250)	(24,451)	(24,652)	(24,853)	(25,054)	(25,255)	(25,456)	(25,657)	(25,858)	(26,059)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$97,090	96,889	96,688	96,487	96,286	96,085	95,884	95,683	95,482	95,281	95,080	94,879	94,678	
6.	Average Net Investment		96,990	96,789	96,588	96,387	96,186	95,985	95,784	95,583	95,382	95,181	94,980	94,779	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		713	712	710	709	701	697	696	694	693	692	690	689	$8,396
	b. Debt Component Grossed Up For Taxes (F)		228	227	227	227	234	235	234	234	233	233	232	232	2,776
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)		1,142	1,140	1,138	1,137	1,136	1,133	1,131	1,129	1,127	1,126	1,123	1,122	13,584
	a. Recoverable Costs Allocated to Energy		1,142	1,140	1,138	1,137	1,136	1,133	1,131	1,129	1,127	1,126	1,123	1,122	13,584
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		1,130	1,128	1,130	1,126	1,120	1,117	1,095	1,088	1,089	1,087	1,090	1,096	13,296
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)		$1,130	$1,128	$1,130	$1,126	$1,120	$1,117	$1,095	$1,088	$1,089	$1,087	$1,090	$1,096	$13,296

Notes:
(A) Applicable depreciable base for Big Bend; account 311.40 ($120,737)
(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). Effective May 7, 2009, Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 2.0%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

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DOCKET NO. 080007-EI
ECRC 2008 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 2009 to December 2009

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		($7,385)	$75,444	$114,696	$33,429	$4,403	$6,944	$24,655	$8,592	$13,992	$21,129	$155,549	$360,416	$811,862
	b. Clearings to Plant		333,163	18,963	6,294	7,671	4,511	85,729	20,497	463	0	0	0	0	477,291
	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)	$83,555,351	$83,888,514	$83,907,477	$83,913,771	$83,921,442	$83,925,953	$84,011,682	$84,032,179	$84,032,642	$84,032,642	$84,032,642	$84,032,642	$84,032,642	
3.	Less: Accumulated Depreciation	(29,343,956)	(29,545,881)	(29,748,612)	(29,951,388)	(30,154,180)	(30,356,990)	(30,559,811)	(30,762,839)	(30,965,917)	(31,168,996)	(31,372,075)	(31,575,154)	(31,778,233)	
4.	CWIP - Non-Interest Bearing	2,455,300	2,114,752	2,171,232	2,279,634	2,305,392	2,305,284	2,226,499	2,230,657	2,238,786	2,252,778	2,273,907	2,429,455	2,789,871	
5.	Net Investment (Lines 2 + 3 + 4)	$56,666,695	56,457,384	56,330,097	56,242,017	56,072,654	55,874,247	55,678,370	55,499,997	55,305,510	55,116,424	54,934,473	54,886,943	55,044,280	
6.	Average Net Investment		56,562,039	56,393,741	56,286,057	56,157,335	55,973,450	55,776,308	55,589,183	55,402,753	55,210,967	55,025,448	54,910,708	54,965,611	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		415,910	414,673	413,881	412,934	407,632	405,252	403,892	402,538	401,144	399,797	398,963	399,362	$4,875,978
	b. Debt Component Grossed Up For Taxes (F)		132,921	132,525	132,272	131,970	135,766	136,299	135,841	135,386	134,917	134,464	134,183	134,318	1,610,862
8.	Investment Expenses														
	a. Depreciation (C)		201,925	202,731	202,776	202,792	202,810	202,821	203,028	203,078	203,079	203,079	203,079	203,079	2,434,277
	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)		750,756	749,929	748,929	747,696	746,208	744,372	742,761	741,002	739,140	737,340	736,225	736,759	8,921,117
	a. Recoverable Costs Allocated to Energy		750,756	749,929	748,929	747,696	746,208	744,372	742,761	741,002	739,140	737,340	736,225	736,759	8,921,117
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666048	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		742,641	741,866	743,580	740,422	735,845	733,978	719,070	714,354	714,456	711,521	714,412	719,703	8,731,848
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)		$742,641	$741,866	$743,580	$740,422	$735,845	$733,978	$719,070	$714,354	$714,456	$711,521	$714,412	$719,703	$8,731,848

Notes:

(A) Applicable depreciable base for Big Bend; account 312.46 ($84,032,642)
(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). Effective May 7, 2009, Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rates are 2.9% .
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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	(4,032,085)	(4,073,727)	(4,115,369)	(4,157,011)	(4,198,653)	(4,240,295)	(4,281,937)	(4,323,579)	(4,365,221)	(4,406,863)	(4,448,505)	(4,490,147)	(4,531,789)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$17,707,652	17,666,010	17,624,368	17,582,726	17,541,084	17,499,442	17,457,800	17,416,158	17,374,516	17,332,874	17,291,232	17,249,590	17,207,948	
6.	Average Net Investment		17,686,831	17,645,189	17,603,547	17,561,905	17,520,263	17,478,621	17,436,979	17,395,337	17,353,695	17,312,053	17,270,411	17,228,769	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		130,054	129,748	129,442	129,136	127,593	126,994	126,691	126,389	126,086	125,784	125,481	125,178	$1,528,576
	b. Debt Component Grossed Up For Taxes (F)		41,564	41,466	41,368	41,270	42,496	42,712	42,610	42,508	42,407	42,305	42,203	42,101	505,010
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)		213,260	212,856	212,452	212,048	211,731	211,348	210,943	210,539	210,135	209,731	209,326	208,921	2,533,290
	a. Recoverable Costs Allocated to Energy		213,260	212,856	212,452	212,048	211,731	211,348	210,943	210,539	210,135	209,731	209,326	208,921	2,533,290
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		210,955	210,567	210,935	209,985	208,790	208,397	204,215	202,968	203,117	202,387	203,124	204,084	2,479,524
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)		$210,955	$210,567	$210,935	$209,985	$208,790	$208,397	$204,215	$202,968	$203,117	$202,387	$203,124	$204,084	$2,479,524

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). Effective May 7, 2009, Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rates are 1.5% and 2.3%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

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DOCKET NO. 080007-EI
ECRC 2008 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 8, PAGE 12 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

Form 42-8E
Page 13 of 26

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		$727	$1,294	$711	$666	$1,402	($358)	$1,610	$1,610	$1,711	$68,662	$44,841	$0	$122,876
	b. Clearings to Plant		727	1,294	711	666	1,402	(358)	1,610	1,610	1,711	68,662	44,841	0	122,876
	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)	$3,338,427	$3,339,154	$3,340,448	$3,341,159	$3,341,825	$3,343,227	$3,342,869	$3,344,479	$3,346,089	$3,347,800	$3,416,462	$3,461,303	$3,461,303	
3.	Less: Accumulated Depreciation	2,678,047	2,669,388	2,660,727	2,652,064	2,643,399	2,634,733	2,626,064	2,617,395	2,608,723	2,600,047	2,591,368	2,582,540	2,573,615	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$6,016,474	6,008,542	6,001,175	5,993,223	5,985,224	5,977,960	5,968,933	5,961,874	5,954,812	5,947,847	6,007,830	6,043,843	6,034,918	
6.	Average Net Investment		6,012,508	6,004,859	5,997,199	5,989,224	5,981,592	5,973,447	5,965,404	5,958,343	5,951,330	5,977,839	6,025,837	6,039,381	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		44,211	44,155	44,098	44,040	43,562	43,401	43,343	43,291	43,240	43,433	43,782	43,880	$524,436
	b. Debt Component Grossed Up For Taxes (F)		14,129	14,111	14,093	14,075	14,509	14,597	14,577	14,560	14,543	14,608	14,725	14,758	173,285
8.	Investment Expenses														
	a. Depreciation (C)		8,659	8,661	8,663	8,665	8,666	8,669	8,669	8,672	8,676	8,679	8,828	8,925	104,432
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		66,999	66,927	66,854	66,780	66,737	66,667	66,589	66,523	66,459	66,720	67,335	67,563	802,153
	a. Recoverable Costs Allocated to Energy		66,999	66,927	66,854	66,780	66,737	66,667	66,589	66,523	66,459	66,720	67,335	67,563	802,153
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		66,275	66,207	66,377	66,130	65,810	65,736	64,465	64,131	64,240	64,384	65,340	65,999	785,094
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)		$66,275	$66,207	$66,377	$66,130	$65,810	$65,736	$64,465	$64,131	$64,240	$64,384	$65,340	$65,999	$785,094

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,675,171), 312.42 ($1,075,718), and 312.43 ($710,414)
(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). Effective May 7, 2009, Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rates are 3.3%, 3.1%, and 2.6%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

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DOCKET NO. 080007-EI
ECRC 2008 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 8, PAGE 13 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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		$129,332	$32,623	$13,401	$20,374	$3,993	$7,958	$22,836	$5,440	$0	$0	$0	$0	$235,957
	b. Clearings to Plant		0	254,582	13,401	20,374	3,993	7,958	22,836	5,440	0	0	0	0	328,584
	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	$8,245,634	$8,259,035	$8,279,409	$8,283,402	$8,291,360	$8,314,196	$8,319,636	$8,319,636	$8,319,636	$8,319,636	$8,319,636	
3.	Less: Accumulated Depreciation	(968,319)	(988,514)	(1,008,709)	(1,029,434)	(1,050,187)	(1,070,983)	(1,091,787)	(1,112,608)	(1,133,476)	(1,154,356)	(1,175,236)	(1,196,116)	(1,216,996)	
4.	CWIP - Non-Interest Bearing	92,627	221,959	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$7,115,360	7,224,497	7,236,925	7,229,601	7,229,222	7,212,419	7,199,573	7,201,588	7,186,160	7,165,280	7,144,400	7,123,520	7,102,640	
6.	Average Net Investment		7,169,929	7,230,711	7,233,263	7,229,412	7,220,821	7,205,996	7,200,581	7,193,874	7,175,720	7,154,840	7,133,960	7,113,080	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		52,722	53,169	53,187	53,159	52,587	52,356	52,317	52,268	52,136	51,985	51,833	51,681	$629,400
	b. Debt Component Grossed Up For Taxes (F)		16,849	16,992	16,998	16,989	17,514	17,609	17,596	17,579	17,535	17,484	17,433	17,382	207,960
8.	Investment Expenses														
	a. Depreciation (C)		20,195	20,195	20,725	20,753	20,796	20,804	20,821	20,868	20,880	20,880	20,880	20,880	248,677
	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)		89,766	90,356	90,910	90,901	90,897	90,769	90,734	90,715	90,551	90,349	90,146	89,943	1,086,037
	a. Recoverable Costs Allocated to Energy		89,766	90,356	90,910	90,901	90,897	90,769	90,734	90,715	90,551	90,349	90,146	89,943	1,086,037
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		88,796	89,385	90,261	90,017	89,635	89,502	87,840	87,453	87,527	87,185	87,475	87,861	1,062,937
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)		$88,796	$89,385	$90,261	$90,017	$89,635	$89,502	$87,840	$87,453	$87,527	$87,185	$87,475	$87,861	$1,062,937

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 ($328,584), 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). Effective May 7, 2009, Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate o
38.575% (expansion factor of 1.63490).
(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
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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	(258,618)	(263,042)	(267,466)	(271,890)	(276,314)	(280,738)	(285,162)	(289,586)	(294,010)	(298,434)	(302,858)	(307,282)	(311,706)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,302,855	1,298,431	1,294,007	1,289,583	1,285,159	1,280,735	1,276,311	1,271,887	1,267,463	1,263,039	1,258,615	1,254,191	1,249,767	
6.	Average Net Investment		1,300,643	1,296,219	1,291,795	1,287,371	1,282,947	1,278,523	1,274,099	1,269,675	1,265,251	1,260,827	1,256,403	1,251,979	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		9,564	9,531	9,499	9,466	9,343	9,289	9,257	9,225	9,193	9,161	9,129	9,096	$111,753
	b. Debt Component Grossed Up For Taxes (F)		3,057	3,046	3,036	3,025	3,112	3,124	3,113	3,103	3,092	3,081	3,070	3,059	36,918
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)		17,045	17,001	16,959	16,915	16,879	16,837	16,794	16,752	16,709	16,666	16,623	16,579	201,759
	a. Recoverable Costs Allocated to Energy		17,045	17,001	16,959	16,915	16,879	16,837	16,794	16,752	16,709	16,666	16,623	16,579	201,759
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		16,861	16,818	16,838	16,750	16,645	16,602	16,258	16,150	16,151	16,082	16,130	16,195	197,480
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$16,861	$16,818	$16,838	$16,750	$16,645	$16,602	$16,258	$16,150	$16,151	$16,082	$16,130	$16,195	$197,480

Notes:
(A) Applicable depreciable base for Polk; account 342.81 ($1,561,473)
(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). Effective May 7, 2009, Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 3.4%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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	(264,638)	(269,755)	(274,872)	(279,989)	(285,106)	(290,223)	(295,340)	(300,457)	(305,574)	(310,691)	(315,808)	(320,925)	(326,042)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,294,092	2,288,975	2,283,858	2,278,741	2,273,624	2,268,507	2,263,390	2,258,273	2,253,156	2,248,039	2,242,922	2,237,805	2,232,688	
6.	Average Net Investment		2,291,534	2,286,417	2,281,300	2,276,183	2,271,066	2,265,949	2,260,832	2,255,715	2,250,598	2,245,481	2,240,364	2,235,247	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		16,850	16,812	16,775	16,737	16,539	16,464	16,426	16,389	16,352	16,315	16,278	16,241	$198,178
	b. Debt Component Grossed Up For Taxes (F)		5,385	5,373	5,361	5,349	5,509	5,537	5,525	5,512	5,500	5,487	5,475	5,462	65,475
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)		27,352	27,302	27,253	27,203	27,165	27,118	27,068	27,018	26,969	26,919	26,870	26,820	325,057
	a. Recoverable Costs Allocated to Energy		27,352	27,302	27,253	27,203	27,165	27,118	27,068	27,018	26,969	26,919	26,870	26,820	325,057
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		27,056	27,008	27,058	26,938	26,788	26,739	26,205	26,046	26,068	25,976	26,074	26,199	318,155
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)		$27,056	$27,008	$27,058	$26,938	$26,788	$26,739	$26,205	$26,046	$26,068	$25,976	$26,074	$26,199	$318,155

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44 ($2,558,730)
(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). Effective May 7, 2009, Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 2.4%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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		$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)	$1,649,121	$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	$1,649,121	$1,649,121	
3.	Less: Accumulated Depreciation	(106,585)	(111,120)	(115,655)	(120,190)	(124,725)	(129,260)	(133,795)	(138,330)	(142,865)	(147,400)	(151,935)	(156,470)	(161,005)	
4.	CWIP - Non-Interest Bearing	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	
5.	Net Investment (Lines 2 + 3 + 4)	$1,910,303	1,905,768	1,901,233	1,896,698	1,892,163	1,887,628	1,883,093	1,878,558	1,874,023	1,869,488	1,864,953	1,860,418	1,855,883	
6.	Average Net Investment		1,908,036	1,903,501	1,898,966	1,894,431	1,889,896	1,885,361	1,880,826	1,876,291	1,871,756	1,867,221	1,862,686	1,858,151	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		14,030	13,997	13,963	13,930	13,764	13,698	13,665	13,633	13,600	13,567	13,534	13,501	$164,882
	b. Debt Component Grossed Up For Taxes (F)		4,484	4,473	4,463	4,452	4,584	4,607	4,596	4,585	4,574	4,563	4,552	4,541	54,474
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)		23,049	23,005	22,961	22,917	22,883	22,840	22,796	22,753	22,709	22,665	22,621	22,577	273,776
	a. Recoverable Costs Allocated to Energy		23,049	23,005	22,961	22,917	22,883	22,840	22,796	22,753	22,709	22,665	22,621	22,577	273,776
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		22,800	22,758	22,797	22,694	22,565	22,521	22,069	21,935	21,951	21,871	21,951	22,054	267,966
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)		$22,800	$22,758	$22,797	$22,694	$22,565	$22,521	$22,069	$21,935	$21,951	$21,871	$21,951	$22,054	$267,966

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41 ($1,649,121)
(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). Effective May 7, 2009, Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 3.3%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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		$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	(96,044)	(100,131)	(104,218)	(108,305)	(112,392)	(116,479)	(120,566)	(124,653)	(128,740)	(132,827)	(136,914)	(141,001)	(145,088)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,485,843	1,481,756	1,477,669	1,473,582	1,469,495	1,465,408	1,461,321	1,457,234	1,453,147	1,449,060	1,444,973	1,440,886	1,436,799	
6.	Average Net Investment		1,483,800	1,479,713	1,475,626	1,471,539	1,467,452	1,463,365	1,459,278	1,455,191	1,451,104	1,447,017	1,442,930	1,438,843	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		10,911	10,881	10,851	10,820	10,686	10,632	10,603	10,573	10,543	10,514	10,484	10,454	$127,952
	b. Debt Component Grossed Up For Taxes (F)		3,487	3,477	3,468	3,458	3,559	3,576	3,566	3,556	3,546	3,536	3,526	3,516	42,271
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)		18,485	18,445	18,406	18,365	18,332	18,295	18,256	18,216	18,176	18,137	18,097	18,057	219,267
	a. Recoverable Costs Allocated to Energy		18,485	18,445	18,406	18,365	18,332	18,295	18,256	18,216	18,176	18,137	18,097	18,057	219,267
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		18,285	18,247	18,275	18,186	18,077	18,040	17,674	17,561	17,569	17,502	17,561	17,639	214,616
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)		$18,285	$18,247	$18,275	$18,186	$18,077	$18,040	$17,674	$17,561	$17,569	$17,502	$17,561	$17,639	$214,616

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42 ($1,581,887)
(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). Effective May 7, 2009, Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 3.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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		$0	$0	$0	$0	$0	($47,000)	$0	$0	$0	$0	$0	$0	($47,000)
	b. Clearings to Plant		0	0	0	0	0	(47,000)	0	0	0	0	0	0	(47,000)
	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)	$2,753,507	$2,753,507	$2,753,507	$2,753,507	$2,753,507	$2,753,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	
3.	Less: Accumulated Depreciation	(49,994)	(55,901)	(61,808)	(67,715)	(73,622)	(79,529)	(85,436)	(91,241)	(97,046)	(102,851)	(108,656)	(114,461)	(120,266)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,703,513	2,697,606	2,691,699	2,685,792	2,679,885	2,673,978	2,621,071	2,615,266	2,609,461	2,603,656	2,597,851	2,592,046	2,586,241	
6.	Average Net Investment		2,700,560	2,694,653	2,688,746	2,682,839	2,676,932	2,647,525	2,618,169	2,612,364	2,606,559	2,600,754	2,594,949	2,589,144	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		19,858	19,814	19,771	19,727	19,495	19,236	19,023	18,981	18,938	18,896	18,854	18,812	$231,405
	b. Debt Component Grossed Up For Taxes (F)		6,346	6,332	6,319	6,305	6,493	6,470	6,398	6,384	6,370	6,355	6,341	6,327	76,440
8.	Investment Expenses														
	a. Depreciation (C)		5,907	5,907	5,907	5,907	5,907	5,907	5,805	5,805	5,805	5,805	5,805	5,805	70,272
	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)		32,111	32,053	31,997	31,939	31,895	31,613	31,226	31,170	31,113	31,056	31,000	30,944	378,117
	a. Recoverable Costs Allocated to Energy		32,111	32,053	31,997	31,939	31,895	31,613	31,226	31,170	31,113	31,056	31,000	30,944	378,117
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		31,764	31,708	31,768	31,628	31,452	31,172	30,230	30,049	30,074	29,969	30,082	30,228	370,124
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)		$31,764	$31,708	$31,768	$31,628	$31,452	$31,172	$30,230	$30,049	$30,074	$29,969	$30,082	$30,228	$370,124

Notes:
(A) Applicable depreciable base for Big Bend; account 312.43 ($1,995,677) 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). Effective May 7, 2009, Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575
(expansion factor of 1.63490).
(C) Applicable depreciation rate is 2.6% and 2.5%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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		$3,164,658	$564,360	$2,860,388	$1,932,745	$3,079,556	$1,977,509	$1,980,544	$2,941,495	$3,308,763	$3,709,737	$6,111,522	$4,931,795	$36,563,073
	b. Clearings to Plant		0	0	0	0	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)	$35,640,098	$38,804,756	$39,369,116	$42,229,504	$44,162,249	$47,241,805	$49,219,314	$51,199,858	$54,141,353	$57,450,117	$61,159,854	$67,271,376	$72,203,171	
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)	$35,640,098	38,804,756	39,369,116	42,229,504	44,162,249	47,241,805	49,219,314	51,199,858	54,141,353	57,450,117	61,159,854	67,271,376	72,203,171	
6.	Average Net Investment		37,222,427	39,086,936	40,799,310	43,195,877	45,702,027	48,230,560	50,209,586	52,670,606	55,795,735	59,304,985	64,215,615	69,737,273	
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 Grossed Up For Taxes (G)		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		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
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). Effective May 7, 2009, Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(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.
(G) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

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DOCKET NO. 080007-EI
ECRC 2008 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 8, PAGE 20 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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		$4,910,215	$3,666,316	$2,677,990	$768,539	$311,390	$187,267	$171,910	$68,900	$43,324	$18,593	$10,138	$195,510	$13,030,092
	b. Clearings to Plant		0	0	0	0	0	0	0	90,252,938	43,324	18,593	10,138	195,510	$90,520,503
	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)	$70,163,346	$75,073,561	$78,739,877	$81,417,867	$82,186,406	$82,497,796	$82,685,063	$82,856,973	$90,252,938	$90,296,262	$90,314,855	$90,324,993	$90,520,503	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	(233,153)	(466,418)	(699,731)	(933,071)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$70,163,346	75,073,561	78,739,877	81,417,867	82,186,406	82,497,796	82,685,063	82,856,973	90,252,938	90,063,109	89,848,437	89,625,262	89,587,432	
6.	Average Net Investment		72,618,454	76,906,719	80,078,872	81,802,137	82,342,101	82,591,430	82,771,018	86,554,956	90,158,024	89,955,773	89,736,850	89,606,347	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	0	0	0	0	344,869	655,058	653,589	651,998	651,050	$2,956,564
	b. Debt Component Grossed Up For Taxes (G)		0	0	0	0	0	0	0	115,990	220,316	219,822	219,287	218,968	994,383
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	0	0	0	233,153	233,265	233,313	233,340	933,071
	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	460,859	1,108,527	1,106,676	1,104,598	1,103,358	4,884,018
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	460,859	1,108,527	1,106,676	1,104,598	1,103,358	4,884,018
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0	0	444,286	1,071,507	1,067,924	1,071,871	1,077,815	4,733,403
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	$444,286	$1,071,507	$1,067,924	$1,071,871	$1,077,815	$4,733,403

Notes:

(A) Applicable depreciable base for Big Bend; account 312.42 ($90,520,503)
(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). Effective May 7, 2009, Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 3.1%
(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.
(G) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

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DOCKET NO. 080007-EI
ECRC 2008 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 8, PAGE 21 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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		$41,648	$30,361	$19,412	$5,714	$46,762	($21,292)	$0	$0	$0	$0	$0	$0	$122,605
	b. Clearings to Plant		41,648	30,361	19,412	5,714	46,762	(21,292)	0	0	0	0	0	0	122,605
	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)	$78,586,604	$78,628,252	$78,658,613	$78,678,025	$78,683,739	$78,730,501	$78,709,209	$78,709,209	$78,709,209	$78,709,209	$78,709,209	$78,709,209	$78,709,209	
3.	Less: Accumulated Depreciation	(913,440)	(1,080,022)	(1,246,694)	(1,413,432)	(1,580,212)	(1,747,004)	(1,913,898)	(2,080,746)	(2,247,594)	(2,414,442)	(2,581,290)	(2,748,138)	(2,914,986)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$77,673,164	77,548,230	77,411,919	77,264,593	77,103,527	76,983,497	76,795,311	76,628,463	76,461,615	76,294,767	76,127,919	75,961,071	75,794,223	
6.	Average Net Investment		77,610,697	77,480,075	77,338,256	77,184,060	77,043,512	76,889,404	76,711,887	76,545,039	76,378,191	76,211,343	76,044,495	75,877,647	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		570,684	569,724	568,681	567,547	561,077	558,653	557,363	556,151	554,938	553,726	552,514	551,302	$6,722,360
	b. Debt Component Grossed Up For Taxes (E)		182,385	182,078	181,745	181,383	186,872	187,892	187,458	187,051	186,643	186,235	185,827	185,420	2,220,989
8.	Investment Expenses														
	a. Depreciation (C)		166,582	166,672	166,738	166,780	166,792	166,894	166,848	166,848	166,848	166,848	166,848	166,848	2,001,546
	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)		919,651	918,474	917,164	915,710	914,741	913,439	911,669	910,050	908,429	906,809	905,189	903,570	10,944,895
	a. Recoverable Costs Allocated to Energy		919,651	918,474	917,164	915,710	914,741	913,439	911,669	910,050	908,429	906,809	905,189	903,570	10,944,895
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		909,711	908,599	910,614	906,801	902,037	900,684	882,590	877,323	878,092	875,055	878,370	882,652	10,712,528
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)		$909,711	$908,599	$910,614	$906,801	$902,037	$900,684	$882,590	$877,323	$878,092	$875,055	$878,370	$882,652	$10,712,528

Notes:
(A) Applicable depreciable base for Big Bend; account 311.43 ($3,162,013) and 312.43 ($75,547,196)
(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). Effective May 7, 2009, Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor
(C) Applicable depreciation rates are 1.2% and 2.6%
(D) Line 9a x Line 10
(E) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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		$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)	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	
3.	Less: Accumulated Depreciation	(2,383,285)	(2,505,652)	(2,628,019)	(2,750,386)	(2,872,753)	(2,995,120)	(3,117,487)	(3,239,854)	(3,362,221)	(3,484,588)	(3,606,955)	(3,729,322)	(3,851,689)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$58,800,052	58,677,685	58,555,318	58,432,951	58,310,584	58,188,217	58,065,850	57,943,483	57,821,116	57,698,749	57,576,382	57,454,015	57,331,648	
6.	Average Net Investment		58,738,869	58,616,502	58,494,135	58,371,768	58,249,401	58,127,034	58,004,667	57,882,300	57,759,933	57,637,566	57,515,199	57,392,832	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		431,917	431,017	430,117	429,217	424,207	422,332	421,443	420,553	419,664	418,775	417,886	416,997	$5,084,125
	b. Debt Component Grossed Up For Taxes (F)		138,036	137,749	137,461	137,174	141,286	142,043	141,744	141,445	141,146	140,847	140,548	140,249	1,679,728
8.	Investment Expenses														
	a. Depreciation (C)		122,367	122,367	122,367	122,367	122,367	122,367	122,367	122,367	122,367	122,367	122,367	122,367	1,468,404
	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)		692,320	691,133	689,945	688,758	687,860	686,742	685,554	684,365	683,177	681,989	680,801	679,613	8,232,257
	a. Recoverable Costs Allocated to Energy		692,320	691,133	689,945	688,758	687,860	686,742	685,554	684,365	683,177	681,989	680,801	679,613	8,232,257
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	-
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		684,837	683,702	685,017	682,057	678,307	677,153	663,687	659,754	660,362	658,108	660,630	663,880	8,057,494
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)		$684,837	$683,702	$685,017	$682,057	$678,307	$677,153	$663,687	$659,754	$660,362	$658,108	$660,630	$663,880	$8,057,494

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44 ($61,183,337)
(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). Effective May 7, 2009, Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 2.4%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

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DOCKET NO. 080007-EI
ECRC 2008 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 8, PAGE 23 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

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		($2,053)	$0	$841	$641	$135	$104	$0	$0	$0	$0	$0	$0	($332)
	b. Clearings to Plant		(2,053)	0	841	641	135	104	0	0	0	0	0	0	(332)
	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)	$11,564,783	$11,562,730	$11,562,730	$11,563,571	$11,564,212	$11,564,347	$11,564,451	$11,564,451	$11,564,451	$11,564,451	$11,564,451	$11,564,451	$11,564,451	
3.	Less: Accumulated Depreciation	(293,528)	(315,815)	(338,098)	(360,381)	(382,665)	(404,951)	(427,237)	(449,523)	(471,809)	(494,095)	(516,381)	(538,667)	(560,953)	
4.	CWIP - Non-Interest Bearing	16,183	16,183	16,183	16,183	16,183	16,183	16,183	16,183	16,183	16,183	16,183	16,183	16,183	
5.	Net Investment (Lines 2 + 3 + 4)	$11,287,438	11,263,098	11,240,815	11,219,373	11,197,730	11,175,579	11,153,397	11,131,111	11,108,825	11,086,539	11,064,253	11,041,967	11,019,681	
6.	Average Net Investment		11,275,268	11,251,956	11,230,094	11,208,551	11,186,654	11,164,488	11,142,254	11,119,968	11,097,682	11,075,396	11,053,110	11,030,824	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		82,909	82,738	82,577	82,418	81,468	81,117	80,956	80,794	80,632	80,470	80,308	80,146	$976,533
	b. Debt Component Grossed Up For Taxes (F)		26,497	26,442	26,391	26,340	27,134	27,282	27,228	27,173	27,119	27,065	27,010	26,956	322,637
8.	Investment Expenses														
	a. Depreciation (C)		22,287	22,283	22,283	22,284	22,286	22,286	22,286	22,286	22,286	22,286	22,286	22,286	267,425
	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)		131,693	131,463	131,251	131,042	130,888	130,685	130,470	130,253	130,037	129,821	129,604	129,388	1,566,595
	a. Recoverable Costs Allocated to Energy		131,693	131,463	131,251	131,042	130,888	130,685	130,470	130,253	130,037	129,821	129,604	129,388	1,566,595
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		130,270	130,050	130,314	129,767	129,070	128,860	126,308	125,569	125,694	125,275	125,764	126,393	1,533,334
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)		$130,270	$130,050	$130,314	$129,767	$129,070	$128,860	$126,308	$125,569	$125,694	$125,275	$125,764	$126,393	$1,533,334

Notes:

(A) Applicable depreciable base for Big Bend; account 312.44 ($1,456,209) and 312.45 ($9,779,842)
(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). Effective May 7, 2009, Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 2.4% and 2.3%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

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DOCKET NO. 080007-EI
ECRC 2008 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 2009 to December 2009

Form 42-8E

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		$18,372	$26,041	$35,113	($4,588)	$10,881	$9,433	$12,737	$28,876	$0	$0	$0	$0	$136,865
	b. Clearings to Plant		0	0	0	1,091,259	10,881	9,433	12,737	28,876	0	0	0	0	$1,153,186
	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	$1,091,259	$1,102,140	$1,111,573	$1,124,310	$1,153,186	$1,153,186	$1,153,186	$1,153,186	$1,153,186	
3.	Less: Accumulated Depreciation	0	0	0	0	0	(2,728)	(5,483)	(8,262)	(11,073)	(13,956)	(16,839)	(19,722)	(22,605)	
4.	CWIP - Non-Interest Bearing	1,016,321	1,034,693	1,060,734	1,095,847	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,016,321	1,034,693	1,060,734	1,095,847	1,091,259	1,099,412	1,106,090	1,116,048	1,142,113	1,139,230	1,136,347	1,133,464	1,130,581	
6.	Average Net Investment		1,025,507	1,047,714	1,078,291	1,093,553	1,095,336	1,102,751	1,111,069	1,129,081	1,140,672	1,137,789	1,134,906	1,132,023	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		7,541	7,704	7,929	8,041	7,977	8,012	8,073	8,204	8,288	8,267	8,246	8,225	$96,507
	b. Debt Component Grossed Up For Taxes (F)		2,410	2,462	2,534	2,570	2,657	2,695	2,715	2,759	2,787	2,780	2,773	2,766	31,908
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	2,728	2,755	2,779	2,811	2,883	2,883	2,883	2,883	22,605
	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)		9,951	10,166	10,463	10,611	13,362	13,462	13,567	13,774	13,958	13,930	13,902	13,874	151,020
	a. Recoverable Costs Allocated to Energy		9,951	10,166	10,463	10,611	13,362	13,462	13,567	13,774	13,958	13,930	13,902	13,874	151,020
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	
11.	Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	
12.	Retail Energy-Related Recoverable Costs (D)		9,843	10,057	10,388	10,508	13,176	13,274	13,134	13,279	13,492	13,442	13,490	13,553	147,636
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)		$9,843	$10,057	$10,388	$10,508	$13,176	$13,274	$13,134	$13,279	$13,492	$13,442	$13,490	$13,553	$147,636

Notes:

(A) Applicable depreciable base for Big Bend and Polk; accounts 312.41, 312.43, 312.44, 315.40 ($1,153,186) and 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). Effective May 7, 2009, Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 3.3%, 2.6%, 2.4%, 3.0%, and 3.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.82% x 1/12. Effective May 7, 2009, Line 6 x 2.9324% x 1/12.

DOCKET NO. 080007-EI
ECRC 2008 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 8, PAGE 25 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2009 to December 2009

For Project: SO_2 Emissions Allowances
(in Dollars)

Line Description	Beginning of Period Amount	Actual January 09	Actual February 09	Actual March 09	Actual April 09	Actual May 09	Actual June 09	Estimated July 09	Estimated August 09	Estimated September 09	Estimated October 09	Estimated November 09	Estimated December 09	End of Period Total
1. Investments														
a. Purchases/Transfers		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	$0
c. Auction Proceeds/Other		0	0	0	0	92,691	0	0	0	0	0	0	0	$92,691
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	(44,985)	(44,720)	(44,531)	(44,393)	(44,150)	(43,925)	(43,674)	(43,227)	(42,705)	(42,155)	(41,625)	(41,065)	(40,594)	
3. Total Working Capital Balance	($44,985)	($44,720)	($44,531)	($44,393)	($44,150)	($43,925)	($43,674)	($43,227)	($42,705)	($42,155)	($41,625)	($41,065)	($40,594)	
4. Average Net Working Capital Balance		($44,852)	($44,626)	($44,462)	($44,271)	($44,037)	($43,799)	($43,450)	($42,966)	($42,430)	($41,890)	($41,345)	($40,830)	
5. Return on Average Net Working Capital Balance														
a. Equity Component Grossed Up For Taxes (A)		(330)	(328)	(327)	(326)	(321)	(318)	(316)	(312)	(308)	(304)	(300)	(297)	($3,787)
b. b. Debt Component Grossed Up For Taxes (E)		(105)	(105)	(104)	(104)	(107)	(107)	(106)	(105)	(104)	(102)	(101)	(100)	($1,250)
6. Total Return Component		(435)	(433)	(431)	(430)	(428)	(425)	(422)	(417)	(412)	(406)	(401)	(397)	($5,037)
7. Expenses:														
a. Gains		0	0	0	0	(92,691)	0	0	0	0	0	0	0	(92,691)
b. Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
c. SO_2 Allowance Expense		6,808	2,253	1,952	1,311	1,037	1,005	79,253	79,178	76,550	72,470	71,241	77,129	470,187
8. Net Expenses (B)		6,808	2,253	1,952	1,311	(91,654)	1,005	79,253	79,178	76,550	72,470	71,241	77,129	377,496
9. Total System Recoverable Expenses (Lines 6 + 7)		$6,373	$1,820	$1,521	$881	($92,082)	$580	$78,831	$78,761	$76,138	$72,064	$70,840	$76,732	$372,459
a. Recoverable Costs Allocated to Energy		6,373	1,820	1,521	881	(92,082)	580	78,831	78,761	76,138	72,064	70,840	76,732	372,459
b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10. Energy Jurisdictional Factor		0.9891913	0.9892481	0.9928581	0.9902713	0.9861120	0.9860367	0.9681036	0.9640382	0.9666046	0.9649832	0.9703716	0.9768498	0.9787224
11. Demand Jurisdictional Factor		0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232	0.9587232
12. Retail Energy-Related Recoverable Costs (C)		6,304	1,800	1,510	872	(90,803)	572	76,317	75,929	73,595	69,541	68,741	74,956	359,334
13. Retail Demand-Related Recoverable Costs (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
14. Total Juris. Recoverable Costs (Lines 12 + 13)		$6,304	$1,800	$1,510	$872	($90,803)	$572	$76,317	$75,929	$73,595	$69,541	$68,741	$74,956	$359,334

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). Effective May 7, 2009, Line 4 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(B) Line 8 is reported on Schedule 2P
(C) Line 9a x Line 10
(D) Line 9b x Line 11
(E) Line 4 x 2.82% x 1/12. Effective May 7, 2009, Line 4 x 2.9324% x 1/12.

INDEX

ENVIRONMENTAL COST RECOVERY COMMISSION FORMS

JANUARY 2010 THROUGH DECEMBER 2010

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 30
COMPANY Tampa Electric Company (Direct)
WITNESS Howard T. Bryant (HTB-3)
DATE 11/02/09

Form 42 - 1P

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to Be Recovered

For the Projected Period
January 2010 to December 2010

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)	$18,046,706	$168,214	$18,214,920
b. Projected Capital Projects (Form 42-3P, Lines 7, 8 & 9)	57,074,029	149,366	57,223,395
c. Total Jurisdictional Revenue Requirements for the projected period (Lines 1a + 1b)	75,120,735	317,580	75,438,315
2. True-up for Estimated Over/(Under) Recovery for the current period January 2009 to December 2009* (Form 42-2E, Line 5 + 6 + 10)	(9,193,784)	(85,345)	(9,279,129)
3. Final True-up for the period January 2008 to December 2008 (Form 42-1A, Line 3)	(7,994,185)	(118,808)	(8,112,993)
4. Total Jurisdictional Amount to Be Recovered/(Refunded) in the projection period January 2010 to December 2010 (Line 1 - Line 2- Line 3)	92,308,704	521,733	92,830,437
5. Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier)	$92,375,166	$522,109	$92,897,275

* 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. 090007-EI
ECRC 2010 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 1

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	$291,800	$272,000	$371,100	$347,700	$402,800	$360,400	$299,700	$379,800	$361,700	$438,900	$364,600	$351,300	$4,241,800		$4,241,800
	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	46,720	42,098	46,759	47,134	48,787	47,057	48,742	48,742	47,056	48,796	45,037	46,636	563,564		563,564
	d. Big Bend Units 1 & 2 FGD (Less Gypsum Revenue)	692,600	820,400	577,300	504,900	602,200	602,300	484,400	634,700	635,600	621,500	636,200	631,200	7,443,300		7,443,300
	e. Big Bend PM Minimization and Monitoring	51,900	60,700	64,900	57,200	43,300	24,500	25,100	25,100	24,500	43,300	24,500	25,000	470,000		470,000
	f. Big Bend NO_x Emissions Reduction	58,000	58,000	8,000	40,500	115,500	28,000	8,000	8,000	8,000	8,000	28,000	28,000	396,000		396,000
	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	0	0	10,000	0	10,000	0	10,000	0	0	0	0	0	30,000	30,000	
	i. Polk NO_x Reduction	3,500	3,500	7,000	4,000	3,500	4,000	4,000	4,000	3,500	6,000	3,500	3,500	50,000		50,000
	j. Bayside SCR and Ammonia	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	114,000		114,000
	k. Big Bend Unit 4 SOFA	0	0	0	21,000	31,000	10,000	0	0	0	0	0	0	62,000		62,000
	l. Big Bend Unit 1 Pre-SCR	25,000	25,000	25,000	0	0	0	0	0	0	0	0	0	75,000		75,000
	m. Big Bend Unit 2 Pre-SCR	0	21,000	10,000	0	0	0	0	0	0	0	0	0	31,000		31,000
	n. Big Bend Unit 3 Pre-SCR	0	0	21,000	10,000	0	0	0	0	0	0	0	0	31,000		31,000
	o. Clean Water Act Section 316(b) Phase II Study	0	0	20,000	0	20,000	0	20,000	0	0	0	0	0	60,000	60,000	
	p. Arsenic Groundwater Standard Program	0	0	7,000	0	0	7,000	10,000	0	13,000	0	0	13,000	50,000	50,000	
	q. Big Bend 1 SCR	0	0	0	0	202,100	115,000	118,400	117,600	115,100	102,600	112,900	117,900	1,001,600		1,001,600
	r. Big Bend 2 SCR	149,200	98,500	134,100	125,400	141,100	146,800	151,300	150,200	146,900	129,800	144,100	150,700	1,668,100		1,668,100
	s. Big Bend 3 SCR	149,700	115,000	124,500	126,800	143,100	148,800	153,300	152,200	148,900	109,300	145,000	151,500	1,668,100		1,668,100
	t. Big Bend 4 SCR	72,400	57,000	61,900	38,300	52,200	71,200	73,600	73,100	71,300	65,000	69,900	72,800	778,700		778,700
	u. Clean Air Mercury Rule	0	0	2,000	0	0	2,000	0	0	2,000	0	0	2,000	8,000		8,000
2.	Total of O&M Activities	1,584,820	1,582,698	1,500,059	1,332,434	1,825,087	1,576,557	1,416,042	1,602,942	1,587,056	1,582,696	1,583,237	1,603,036	18,776,664	174,500	18,602,164
3.	Recoverable Costs Allocated to Energy	1,550,320	1,582,698	1,463,059	1,332,434	1,795,087	1,569,557	1,376,042	1,602,942	1,574,056	1,582,696	1,583,237	1,590,036	18,602,164		
	Recoverable Costs Allocated to Demand	34,500	0	37,000	0	30,000	7,000	40,000	0	13,000	0	0	13,000	174,500		
5.	Retail Energy Jurisdictional Factor	0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374			
6.	Retail Demand Jurisdictional Factor	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735			
7.	Jurisdictional Energy Recoverable Costs (A)	1,516,039	1,539,605	1,426,059	1,293,422	1,728,486	1,523,593	1,332,635	1,546,121	1,522,216	1,528,253	1,536,911	1,553,366	18,046,706		
8.	Jurisdictional Demand Recoverable Costs (B)	33,257	0	35,667	0	28,919	6,748	38,559	0	12,532	0	0	12,532	168,214		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,549,296	$1,539,605	$1,461,726	$1,293,422	$1,757,405	$1,530,341	$1,371,194	$1,546,121	$1,534,748	$1,528,253	$1,536,911	$1,565,898	$18,214,920		

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

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DOCKET NO. 090007-EI
ECRC 2010 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 2

Form 42-3P

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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 Desulfurization Integration	$64,538	$64,385	$64,232	$64,079	$63,925	$63,771	$63,619	$63,465	$63,312	$63,158	$63,005	$62,852	$764,341		$764,341
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	35,893	35,763	35,632	35,503	35,373	35,242	35,112	34,981	34,852	34,721	34,591	34,461	422,124		422,124
	c.	Big Bend Unit 4 Continuous Emissions Monitors	6,623	6,609	6,594	6,579	6,565	6,550	6,535	6,520	6,506	6,491	6,476	6,462	78,510		78,510
	d.	Big Bend Fuel Oil Tank # 1 Upgrade	4,480	4,471	4,460	4,450	4,439	4,428	4,418	4,408	4,397	4,387	4,376	4,365	53,079	$ 53,079	
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	7,370	7,352	7,335	7,319	7,301	7,284	7,267	7,249	7,232	7,215	7,197	7,181	87,302	87,302	
	f.	Phillips Upgrade Tank # 1 for FDEP	480	478	477	476	474	473	472	470	469	468	466	464	5,667	5,667	
	g.	Phillips Upgrade Tank # 4 for FDEP	754	751	750	747	745	743	740	738	736	734	731	730	8,899	8,899	
	h.	Big Bend Unit 1 Classifier Replacement	11,343	11,308	11,273	11,237	11,202	11,167	11,132	11,097	11,062	11,027	10,991	10,956	133,795		133,795
	i.	Big Bend Unit 2 Classifier Replacement	8,217	8,193	8,167	8,143	8,118	8,094	8,069	8,044	8,019	7,995	7,970	7,945	96,974		96,974
	j.	Big Bend Section 114 Mercury Testing Platform	1,119	1,118	1,115	1,114	1,111	1,110	1,107	1,106	1,103	1,102	1,100	1,098	13,303		13,303
	k.	Big Bend Units 1 & 2 FGD (Less Gypsum Revenue)	736,939	737,118	737,289	735,721	741,734	739,684	737,635	735,585	733,536	731,487	729,437	727,387	8,823,552		8,823,552
	l.	Big Bend FGD Optimization and Utilization	208,518	208,113	207,709	207,304	206,901	206,496	206,092	205,687	205,283	204,879	204,474	204,070	2,475,526		2,475,526
	m.	Big Bend NO_x Emissions Reduction	67,476	67,390	67,304	67,217	67,130	67,043	66,957	66,870	66,784	66,697	66,610	66,524	804,002		804,002
	n.	Big Bend PM Minimization and Monitoring	89,789	89,654	89,452	89,249	89,046	88,843	88,640	88,437	88,234	88,032	87,829	87,626	1,064,831		1,064,831
	o.	Polk NO_x Emissions Reduction	16,537	16,494	16,451	16,408	16,365	16,323	16,279	16,236	16,193	16,150	16,108	16,065	195,609		195,609
	p.	Big Bend Unit 4 SOFA	26,770	26,720	26,671	26,621	26,572	26,521	26,472	26,422	26,373	26,323	26,274	26,223	317,962		317,962
	q.	Big Bend Unit 1 Pre-SCR	22,533	22,489	22,444	22,400	22,356	22,312	22,268	22,224	22,180	22,136	22,092	22,048	267,482		267,482
	r.	Big Bend Unit 2 Pre-SCR	18,017	17,978	17,938	17,898	17,859	17,819	17,779	17,740	17,700	17,660	17,621	17,581	213,590		213,590
	s.	Big Bend Unit 3 Pre-SCR	30,888	30,832	30,774	30,718	30,662	30,606	30,550	30,493	30,436	30,380	30,324	30,268	366,931		366,931
	t.	Big Bend Unit 1 SCR	0	0	0	0	889,336	1,186,187	1,185,685	1,183,181	1,180,677	1,178,174	1,175,670	1,173,167	9,152,077		9,152,077
	u.	Big Bend Unit 2 SCR	1,102,544	1,100,274	1,098,003	1,095,733	1,093,462	1,091,192	1,088,921	1,086,651	1,084,381	1,082,110	1,079,840	1,077,568	13,080,679		13,080,679
	v.	Big Bend Unit 3 SCR	901,949	900,329	898,710	897,090	895,469	893,849	892,230	890,610	888,989	887,369	885,750	884,130	10,716,474		10,716,474
	w.	Big Bend Unit 4 SCR	678,425	677,237	676,049	674,861	673,673	672,485	671,297	670,109	668,920	667,732	666,544	665,356	8,062,688		8,062,688
	x.	Big Bend FGD System Reliability	129,171	128,955	128,739	128,523	128,306	129,303	131,514	134,939	140,791	145,914	148,369	150,094	1,624,618		1,624,618
	y.	Clean Air Mercury Rule	13,956	14,037	14,107	14,225	14,197	14,169	14,141	14,111	14,083	14,055	14,026	13,998	169,105		169,105
	z.	SO_2 Emissions Allowances (B)	(393)	(390)	(387)	(385)	(382)	(378)	(375)	(372)	(369)	(365)	(362)	(358)	(4,516)		(4,516)
		Total Investment Projects - Recoverable Costs	4,183,936	4,177,658	4,171,288	4,163,230	5,051,939	5,341,316	5,334,556	5,327,001	5,321,879	5,316,031	5,307,509	5,298,261	58,994,604	$ 154,947	$ 58,839,657
3.		Recoverable Costs Allocated to Energy	4,170,852	4,164,606	4,158,266	4,150,238	5,038,980	5,328,388	5,321,659	5,314,136	5,309,045	5,303,227	5,294,739	5,285,521	58,839,657		
4.		Recoverable Costs Allocated to Demand	13,084	13,052	13,022	12,992	12,959	12,928	12,897	12,865	12,834	12,804	12,770	12,740	154,947		
5.		Retail Energy Jurisdictional Factor	0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374			
6.		Retail Demand Jurisdictional Factor	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735			
7.		Jurisdictional Energy Recoverable Costs (C)	4,078,626	4,051,214	4,053,107	4,028,724	4,852,024	5,172,347	5,153,790	5,125,762	5,134,196	5,120,801	5,139,815	5,163,623	57,074,029		
8.		Jurisdictional Demand Recoverable Costs (D)	12,613	12,582	12,553	12,524	12,492	12,462	12,432	12,402	12,372	12,343	12,310	12,281	149,366		
9.		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$4,091,239	$4,063,796	$4,065,660	$4,041,248	$4,864,516	$5,184,809	$5,166,222	$5,138,164	$5,146,568	$5,133,144	$5,152,125	$5,175,904	$57,223,395		

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

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EXHIBIT NO. HTB-3
DOCUMENT NO. 3

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	(3,211,293)	(3,227,086)	(3,242,879)	(3,258,672)	(3,274,465)	(3,290,258)	(3,306,051)	(3,321,844)	(3,337,637)	(3,353,430)	(3,369,223)	(3,385,016)	(3,400,809)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$5,028,365	5,012,572	4,996,779	4,980,986	4,965,193	4,949,400	4,933,607	4,917,814	4,902,021	4,886,228	4,870,435	4,854,642	4,838,849	
6.	Average Net Investment		5,020,469	5,004,676	4,988,883	4,973,090	4,957,297	4,941,504	4,925,711	4,909,918	4,894,125	4,878,332	4,862,539	4,846,746	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		36,477	36,362	36,248	36,133	36,018	35,903	35,789	35,674	35,559	35,444	35,330	35,215	$430,152
	b. Debt Component Grossed Up For Taxes (F)		12,268	12,230	12,191	12,153	12,114	12,075	12,037	11,998	11,960	11,921	11,882	11,844	144,673
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)		64,538	64,385	64,232	64,079	63,925	63,771	63,619	63,465	63,312	63,158	63,005	62,852	764,341
	a. Recoverable Costs Allocated to Energy		64,538	64,385	64,232	64,079	63,925	63,771	63,619	63,465	63,312	63,158	63,005	62,852	764,341
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		63,111	62,632	62,608	62,203	61,553	61,903	61,612	61,215	61,227	60,985	61,161	61,402	741,612
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)		$63,111	$62,632	$62,608	$62,203	$61,553	$61,903	$61,612	$61,215	$61,227	$60,985	$61,161	$61,402	$741,612

Notes:
(A) Applicable depreciable base for Big Bend; account 312.45 ($8,239,658)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 2.3%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	(2,695,310)	(2,708,719)	(2,722,128)	(2,735,537)	(2,748,946)	(2,762,355)	(2,775,764)	(2,789,173)	(2,802,582)	(2,815,991)	(2,829,400)	(2,842,809)	(2,856,218)	
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)	$2,322,424	2,309,015	2,295,606	2,282,197	2,268,788	2,255,379	2,241,970	2,228,561	2,215,152	2,201,743	2,188,334	2,174,925	2,161,516	
6.	Average Net Investment		2,315,720	2,302,311	2,288,902	2,275,493	2,262,084	2,248,675	2,235,266	2,221,857	2,208,448	2,195,039	2,181,630	2,168,221	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		16,825	16,728	16,630	16,533	16,436	16,338	16,241	16,143	16,046	15,948	15,851	15,754	$195,473
	b. Debt Component Grossed Up For Taxes (F)		5,659	5,626	5,593	5,561	5,528	5,495	5,462	5,429	5,397	5,364	5,331	5,298	65,743
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)		35,893	35,763	35,632	35,503	35,373	35,242	35,112	34,981	34,852	34,721	34,591	34,461	422,124
	a. Recoverable Costs Allocated to Energy		35,893	35,763	35,632	35,503	35,373	35,242	35,112	34,981	34,852	34,721	34,591	34,461	422,124
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		35,099	34,789	34,731	34,464	34,061	34,210	34,004	33,741	33,704	33,527	33,579	33,666	409,575
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)		$35,099	$34,789	$34,731	$34,464	$34,061	$34,210	$34,004	$33,741	$33,704	$33,527	$33,579	$33,666	$409,575

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,676,217) and 312.42 ($2,341,517)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rates are 3.3% and 3.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	(339,461)	(340,977)	(342,493)	(344,009)	(345,525)	(347,041)	(348,557)	(350,073)	(351,589)	(353,105)	(354,621)	(356,137)	(357,653)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$526,750	525,234	523,718	522,202	520,686	519,170	517,654	516,138	514,622	513,106	511,590	510,074	508,558	
6.	Average Net Investment		525,992	524,476	522,960	521,444	519,928	518,412	516,896	515,380	513,864	512,348	510,832	509,316	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		3,822	3,811	3,800	3,789	3,778	3,767	3,756	3,745	3,734	3,723	3,712	3,701	$45,138
	b. Debt Component Grossed Up For Taxes (F)		1,285	1,282	1,278	1,274	1,271	1,267	1,263	1,259	1,256	1,252	1,248	1,245	15,180
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)		6,623	6,609	6,594	6,579	6,565	6,550	6,535	6,520	6,506	6,491	6,476	6,462	78,510
	a. Recoverable Costs Allocated to Energy		6,623	6,609	6,594	6,579	6,565	6,550	6,535	6,520	6,506	6,491	6,476	6,462	78,510
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		6,477	6,429	6,427	6,386	6,321	6,358	6,329	6,289	6,292	6,268	6,287	6,313	76,176
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)		$6,477	$6,429	$6,427	$6,386	$6,321	$6,358	$6,329	$6,289	$6,292	$6,268	$6,287	$6,313	$76,176

Notes:
(A) Applicable depreciable base for Big Bend; account 315.44 ($866,211)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 2.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	(146,560)	(147,638)	(148,716)	(149,794)	(150,872)	(151,950)	(153,028)	(154,106)	(155,184)	(156,262)	(157,340)	(158,418)	(159,496)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$351,018	349,940	348,862	347,784	346,706	345,628	344,550	343,472	342,394	341,316	340,238	339,160	338,082	
6.	Average Net Investment		350,479	349,401	348,323	347,245	346,167	345,089	344,011	342,933	341,855	340,777	339,699	338,621	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		2,546	2,539	2,531	2,523	2,515	2,507	2,499	2,492	2,484	2,476	2,468	2,460	$30,040
	b. Debt Component Grossed Up For Taxes (F)		856	854	851	849	846	843	841	838	835	833	830	827	10,103
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)		4,480	4,471	4,460	4,450	4,439	4,428	4,418	4,408	4,397	4,387	4,376	4,365	53,079
	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		4,480	4,471	4,460	4,450	4,439	4,428	4,418	4,408	4,397	4,387	4,376	4,365	53,079
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
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)		4,319	4,310	4,299	4,290	4,279	4,268	4,259	4,249	4,239	4,229	4,218	4,208	51,167
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,319	$4,310	$4,299	$4,290	$4,279	$4,268	$4,259	$4,249	$4,239	$4,229	$4,218	$4,208	$51,167

Notes:

(A) Applicable depreciable base for Big Bend; account 312.40 ($497,578)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 2.6%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	(241,072)	(242,845)	(244,618)	(246,391)	(248,164)	(249,937)	(251,710)	(253,483)	(255,256)	(257,029)	(258,802)	(260,575)	(262,348)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$577,329	575,556	573,783	572,010	570,237	568,464	566,691	564,918	563,145	561,372	559,599	557,826	556,053	
6.	Average Net Investment		576,443	574,670	572,897	571,124	569,351	567,578	565,805	564,032	562,259	560,486	558,713	556,940	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,188	4,175	4,162	4,150	4,137	4,124	4,111	4,098	4,085	4,072	4,059	4,047	$49,408
	b. Debt Component Grossed Up For Taxes (F)		1,409	1,404	1,400	1,396	1,391	1,387	1,383	1,378	1,374	1,370	1,365	1,361	16,618
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)		7,370	7,352	7,335	7,319	7,301	7,284	7,267	7,249	7,232	7,215	7,197	7,181	87,302
	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		7,370	7,352	7,335	7,319	7,301	7,284	7,267	7,249	7,232	7,215	7,197	7,181	87,302
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
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)		7,104	7,087	7,071	7,055	7,038	7,022	7,005	6,988	6,971	6,955	6,938	6,922	84,156
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$7,104	$7,087	$7,071	$7,055	$7,038	$7,022	$7,005	$6,988	$6,971	$6,955	$6,938	$6,922	$84,156

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40 ($818,401)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 2.6%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	(22,536)	(22,679)	(22,822)	(22,965)	(23,108)	(23,251)	(23,394)	(23,537)	(23,680)	(23,823)	(23,966)	(24,109)	(24,252)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$34,741	34,598	34,455	34,312	34,169	34,026	33,883	33,740	33,597	33,454	33,311	33,168	33,025	
6.	Average Net Investment		34,670	34,527	34,384	34,241	34,098	33,955	33,812	33,669	33,526	33,383	33,240	33,097	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		252	251	250	249	248	247	246	245	244	243	242	240	$2,957
	b. Debt Component Grossed Up For Taxes (F)		85	84	84	84	83	83	83	82	82	82	81	81	994
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)		480	478	477	476	474	473	472	470	469	468	466	464	5,667
	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		480	478	477	476	474	473	472	470	469	468	466	464	5,667
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
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)		463	461	460	459	457	456	455	453	452	451	449	447	5,463
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$463	$461	$460	$459	$457	$456	$455	$453	$452	$451	$449	$447	$5,463

Notes:
(A) Applicable depreciable base for Phillips; account 342.28 ($57,277)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 3.0%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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
1.	Investments							
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0
	d. Other		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
3.	Less: Accumulated Depreciation	(36,011)	(36,237)	(36,463)	(36,689)	(36,915)	(37,141)	(37,367)
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 + 3 + 4)	$54,461	54,235	54,009	53,783	53,557	53,331	53,105
6.	Average Net Investment		54,348	54,122	53,896	53,670	53,444	53,218
7.	Return on Average Net Investment							
	a. Equity Component Grossed Up For Taxes (B)		395	393	392	390	388	387
	b. Debt Component Grossed Up For Taxes (F)		133	132	132	131	131	130
8.	Investment Expenses							
	a. Depreciation (C)		226	226	226	226	226	226
	b. Amortization		0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0
	e. Other		0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		754	751	750	747	745	743
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		754	751	750	747	745	743
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)		727	724	723	720	718	716
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$727	$724	$723	$720	$718	$716

Line	Description	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
	b. Clearings to Plant	0	0	0	0	0	0	
	c. Retirements	0	0	0	0	0	0	
	d. Other	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	
3.	Less: Accumulated Depreciation	(37,593)	(37,819)	(38,045)	(38,271)	(38,497)	(38,723)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	52,879	52,653	52,427	52,201	51,975	51,749	
6.	Average Net Investment	52,992	52,766	52,540	52,314	52,088	51,862	
7.	Return on Average Net Investment							
	a. Equity Component Grossed Up For Taxes (B)	385	383	382	380	378	377	$4,630
	b. Debt Component Grossed Up For Taxes (F)	129	129	128	128	127	127	1,557
8.	Investment Expenses							
	a. Depreciation (C)	226	226	226	226	226	226	2,712
	b. Amortization	0	0	0	0	0	0	0
	c. Dismantlement	0	0	0	0	0	0	0
	d. Property Taxes	0	0	0	0	0	0	0
	e. Other	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)	740	738	736	734	731	730	8,899
	a. Recoverable Costs Allocated to Energy	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand	740	738	736	734	731	730	8,899
10.	Energy Jurisdictional Factor	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (E)	713	711	709	708	705	704	8,578
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)	$713	$711	$709	$708	$705	$704	$8,578

Notes:
(A) Applicable depreciable base for Phillips; account 342.28 ($90,472)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 3.0%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	(519,032)	(522,652)	(526,272)	(529,892)	(533,512)	(537,132)	(540,752)	(544,372)	(547,992)	(551,612)	(555,232)	(558,852)	(562,472)	
4.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$797,225	793,605	789,985	786,365	782,745	779,125	775,505	771,885	768,265	764,645	761,025	757,405	753,785	
6.	Average Net Investment		795,415	791,795	788,175	784,555	780,935	777,315	773,695	770,075	766,455	762,835	759,215	755,595	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		5,779	5,753	5,727	5,700	5,674	5,648	5,621	5,595	5,569	5,543	5,516	5,490	$67,615
	b. Debt Component Grossed Up For Taxes (F)		1,944	1,935	1,926	1,917	1,908	1,899	1,891	1,882	1,873	1,864	1,855	1,846	22,740
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)		11,343	11,308	11,273	11,237	11,202	11,167	11,132	11,097	11,062	11,027	10,991	10,956	133,795
	a. Recoverable Costs Allocated to Energy		11,343	11,308	11,273	11,237	11,202	11,167	11,132	11,097	11,062	11,027	10,991	10,956	133,795
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		11,092	11,000	10,988	10,908	10,786	10,840	10,781	10,704	10,698	10,648	10,669	10,703	129,817
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)		$11,092	$11,000	$10,988	$10,908	$10,786	$10,840	$10,781	$10,704	$10,698	$10,648	$10,669	$10,703	$129,817

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41 ($1,316,257)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 3.3%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	(399,222)	(401,766)	(404,310)	(406,854)	(409,398)	(411,942)	(414,486)	(417,030)	(419,574)	(422,118)	(424,662)	(427,206)	(429,750)	
4.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$585,572	583,028	580,484	577,940	575,396	572,852	570,308	567,764	565,220	562,676	560,132	557,588	555,044	
6.	Average Net Investment		584,300	581,756	579,212	576,668	574,124	571,580	569,036	566,492	563,948	561,404	558,860	556,316	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,245	4,227	4,208	4,190	4,171	4,153	4,134	4,116	4,097	4,079	4,060	4,042	$49,722
	b. Debt Component Grossed Up For Taxes (F)		1,428	1,422	1,415	1,409	1,403	1,397	1,391	1,384	1,378	1,372	1,366	1,359	16,724
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)		8,217	8,193	8,167	8,143	8,118	8,094	8,069	8,044	8,019	7,995	7,970	7,945	96,974
	a. Recoverable Costs Allocated to Energy		8,217	8,193	8,167	8,143	8,118	8,094	8,069	8,044	8,019	7,995	7,970	7,945	96,974
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		8,035	7,970	7,960	7,905	7,817	7,857	7,814	7,759	7,755	7,720	7,737	7,762	94,091
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)		$8,035	$7,970	$7,960	$7,905	$7,817	$7,857	$7,814	$7,759	$7,755	$7,720	$7,737	$7,762	$94,091

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42 ($984,794)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 3.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	(26,059)	(26,260)	(26,461)	(26,662)	(26,863)	(27,064)	(27,265)	(27,466)	(27,667)	(27,868)	(28,069)	(28,270)	(28,471)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$94,678	94,477	94,276	94,075	93,874	93,673	93,472	93,271	93,070	92,869	92,668	92,467	92,266	
6.	Average Net Investment		94,578	94,377	94,176	93,975	93,774	93,573	93,372	93,171	92,970	92,769	92,568	92,367	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		687	686	684	683	681	680	678	677	675	674	673	671	$8,149
	b. Debt Component Grossed Up For Taxes (F)		231	231	230	230	229	229	228	228	227	227	226	226	2,742
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)		1,119	1,118	1,115	1,114	1,111	1,110	1,107	1,106	1,103	1,102	1,100	1,098	13,303
	a. Recoverable Costs Allocated to Energy		1,119	1,118	1,115	1,114	1,111	1,110	1,107	1,106	1,103	1,102	1,100	1,098	13,303
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		1,094	1,088	1,087	1,081	1,070	1,077	1,072	1,067	1,067	1,064	1,068	1,073	12,908
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)		$1,094	$1,088	$1,087	$1,081	$1,070	$1,077	$1,072	$1,067	$1,067	$1,064	$1,068	$1,073	$12,908

Notes:
(A) Applicable depreciable base for Big Bend; account 311.40 ($120,737)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 2.0%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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		$82,824	$360,416	$81,000	$2,026	$0	$0	$0	$0	$0	$0	$0	$0	$526,266
	b. Clearings to Plant		0	0	0	3,316,137	0	0	0	0	0	0	0	0	3,316,137
	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)	$84,032,642	$84,032,642	$84,032,642	$84,032,642	$87,348,779	$87,348,779	$87,348,779	$87,348,779	$87,348,779	$87,348,779	$87,348,779	$87,348,779	$87,348,779	
3.	Less: Accumulated Depreciation	(31,778,233)	(31,981,312)	(32,184,391)	(32,387,470)	(32,590,549)	(32,801,642)	(33,012,735)	(33,223,828)	(33,434,921)	(33,646,014)	(33,857,107)	(34,068,200)	(34,279,293)	
4.	CWIP - Non-Interest Bearing	2,789,871	2,872,695	3,233,111	3,314,111	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5.	Net Investment (Lines 2 + 3 + 4)	$55,044,280	54,924,025	55,081,361	54,959,282	54,758,229	54,547,136	54,336,043	54,124,950	53,913,857	53,702,764	53,491,671	53,280,578	53,069,485	
6.	Average Net Investment		54,984,152	55,002,693	55,020,322	54,858,756	54,652,683	54,441,590	54,230,497	54,019,404	53,808,311	53,597,218	53,386,125	53,175,032	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		399,497	399,631	399,759	398,585	397,088	395,554	394,021	392,487	390,953	389,420	387,886	386,352	$4,731,233
	b. Debt Component Grossed Up For Taxes (F)		134,363	134,408	134,451	134,057	133,553	133,037	132,521	132,005	131,490	130,974	130,458	129,942	1,591,259
8.	Investment Expenses														
	a. Depreciation (C)		203,079	203,079	203,079	203,079	211,093	211,093	211,093	211,093	211,093	211,093	211,093	211,093	2,501,060
	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)		736,939	737,118	737,289	735,721	741,734	739,684	737,635	735,585	733,536	731,487	729,437	727,387	8,823,552
	a. Recoverable Costs Allocated to Energy		736,939	737,118	737,289	735,721	741,734	739,684	737,635	735,585	733,536	731,487	729,437	727,387	8,823,552
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		720,644	717,048	718,644	714,180	714,214	718,023	714,367	709,510	709,378	706,325	708,094	710,612	8,561,039
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)		$720,644	$717,048	$718,644	$714,180	$714,214	$718,023	$714,367	$709,510	$709,378	$706,325	$708,094	$710,612	$8,561,039

Notes:
(A) Applicable depreciable base for Big Bend; account 312.46 ($87,348,776)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rates are 2.9% .
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	(4,531,789)	(4,573,431)	(4,615,073)	(4,656,715)	(4,698,357)	(4,739,999)	(4,781,641)	(4,823,283)	(4,864,925)	(4,906,567)	(4,948,209)	(4,989,851)	(5,031,493)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$17,207,948	17,166,306	17,124,664	17,083,022	17,041,380	16,999,738	16,958,096	16,916,454	16,874,812	16,833,170	16,791,528	16,749,886	16,708,244	
6.	Average Net Investment		17,187,127	17,145,485	17,103,843	17,062,201	17,020,559	16,978,917	16,937,275	16,895,633	16,853,991	16,812,349	16,770,707	16,729,065	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		124,876	124,573	124,271	123,968	123,666	123,363	123,061	122,758	122,455	122,153	121,850	121,548	$1,478,542
	b. Debt Component Grossed Up For Taxes (F)		42,000	41,898	41,796	41,694	41,593	41,491	41,389	41,287	41,186	41,084	40,982	40,880	497,280
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)		208,518	208,113	207,709	207,304	206,901	206,496	206,092	205,687	205,283	204,879	204,474	204,070	2,475,526
	a. Recoverable Costs Allocated to Energy		208,518	208,113	207,709	207,304	206,901	206,496	206,092	205,687	205,283	204,879	204,474	204,070	2,475,526
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		203,907	202,447	202,456	201,234	199,225	200,449	199,591	198,396	198,522	197,831	198,491	199,364	2,401,913
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)		$203,907	$202,447	$202,456	$201,234	$199,225	$200,449	$199,591	$198,396	$198,522	$197,831	$198,491	$199,364	$2,401,913

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.45 ($39,818) and 312.45($21,699,919)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rates are 1.5% and 2.3%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	$0	$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)	$3,461,303	$3,461,303	$3,461,303	$3,461,303	$3,461,303	$3,461,303	$3,461,303	$3,461,303	$3,461,303	$3,461,303	$3,461,303	$3,461,303	$3,461,303	
3.	Less: Accumulated Depreciation	2,573,615	2,564,690	2,555,765	2,546,840	2,537,915	2,528,990	2,520,065	2,511,140	2,502,215	2,493,290	2,484,365	2,475,440	2,466,515	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$6,034,918	6,025,993	6,017,068	6,008,143	5,999,218	5,990,293	5,981,368	5,972,443	5,963,518	5,954,593	5,945,668	5,936,743	5,927,818	
6.	Average Net Investment		6,030,456	6,021,531	6,012,606	6,003,681	5,994,756	5,985,831	5,976,906	5,967,981	5,959,056	5,950,131	5,941,206	5,932,281	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		43,815	43,750	43,686	43,621	43,556	43,491	43,426	43,361	43,297	43,232	43,167	43,102	$521,504
	b. Debt Component Grossed Up For Taxes (F)		14,736	14,715	14,693	14,671	14,649	14,627	14,606	14,584	14,562	14,540	14,518	14,497	175,398
8.	Investment Expenses														
	a. Depreciation (C)		8,925	8,925	8,925	8,925	8,925	8,925	8,925	8,925	8,925	8,925	8,925	8,925	107,100
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		67,476	67,390	67,304	67,217	67,130	67,043	66,957	66,870	66,784	66,697	66,610	66,524	804,002
	a. Recoverable Costs Allocated to Energy		67,476	67,390	67,304	67,217	67,130	67,043	66,957	66,870	66,784	66,697	66,610	66,524	804,002
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		65,984	65,555	65,602	65,249	64,639	65,080	64,845	64,500	64,585	64,403	64,661	64,990	780,093
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)		$65,984	$65,555	$65,602	$65,249	$64,639	$65,080	$64,845	$64,500	$64,585	$64,403	$64,661	$64,990	$780,093

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,675,171), 312.42 ($1,075,718), and 312.43 ($710,414)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rates are 3.3%, 3.1%, and 2.6%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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		$10,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$10,000
	b. Clearings to Plant		10,000	0	0	0	0	0	0	0	0	0	0	0	10,000
	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)	$8,319,636	$8,329,636	$8,329,636	$8,329,636	$8,329,636	$8,329,636	$8,329,636	$8,329,636	$8,329,636	$8,329,636	$8,329,636	$8,329,636	$8,329,636	
3.	Less: Accumulated Depreciation	(1,216,996)	(1,237,876)	(1,258,776)	(1,279,676)	(1,300,576)	(1,321,476)	(1,342,376)	(1,363,276)	(1,384,176)	(1,405,076)	(1,425,976)	(1,446,876)	(1,467,776)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$7,102,640	7,091,760	7,070,860	7,049,960	7,029,060	7,008,160	6,987,260	6,966,360	6,945,460	6,924,560	6,903,660	6,882,760	6,861,860	
6.	Average Net Investment		7,097,200	7,081,310	7,060,410	7,039,510	7,018,610	6,997,710	6,976,810	6,955,910	6,935,010	6,914,110	6,893,210	6,872,310	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		51,566	51,450	51,299	51,147	50,995	50,843	50,691	50,539	50,387	50,236	50,084	49,932	$609,169
	b. Debt Component Grossed Up For Taxes (F)		17,343	17,304	17,253	17,202	17,151	17,100	17,049	16,998	16,947	16,896	16,845	16,794	204,882
8.	Investment Expenses														
	a. Depreciation (C)		20,880	20,900	20,900	20,900	20,900	20,900	20,900	20,900	20,900	20,900	20,900	20,900	250,780
	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)		89,789	89,654	89,452	89,249	89,046	88,843	88,640	88,437	88,234	88,032	87,829	87,626	1,064,831
	a. Recoverable Costs Allocated to Energy		89,789	89,654	89,452	89,249	89,046	88,843	88,640	88,437	88,234	88,032	87,829	87,626	1,064,831
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		87,804	87,213	87,190	86,636	85,742	86,241	85,844	85,302	85,328	85,004	85,259	85,605	1,033,168
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)		$87,804	$87,213	$87,190	$86,636	$85,742	$86,241	$85,844	$85,302	$85,328	$85,004	$85,259	$85,605	$1,033,168

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 ($338,584), and 315.44 ($351,594)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(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
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	(311,706)	(316,130)	(320,554)	(324,978)	(329,402)	(333,826)	(338,250)	(342,674)	(347,098)	(351,522)	(355,946)	(360,370)	(364,794)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,249,767	1,245,343	1,240,919	1,236,495	1,232,071	1,227,647	1,223,223	1,218,799	1,214,375	1,209,951	1,205,527	1,201,103	1,196,679	
6.	Average Net Investment		1,247,555	1,243,131	1,238,707	1,234,283	1,229,859	1,225,435	1,221,011	1,216,587	1,212,163	1,207,739	1,203,315	1,198,891	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		9,064	9,032	9,000	8,968	8,936	8,904	8,871	8,839	8,807	8,775	8,743	8,711	$106,650
	b. Debt Component Grossed Up For Taxes (F)		3,049	3,038	3,027	3,016	3,005	2,995	2,984	2,973	2,962	2,951	2,941	2,930	35,871
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)		16,537	16,494	16,451	16,408	16,365	16,323	16,279	16,236	16,193	16,150	16,108	16,065	195,609
	a. Recoverable Costs Allocated to Energy		16,537	16,494	16,451	16,408	16,365	16,323	16,279	16,236	16,193	16,150	16,108	16,065	195,609
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		16,171	16,045	16,035	15,928	15,758	15,845	15,765	15,660	15,660	15,594	15,637	15,694	189,792
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$16,171	$16,045	$16,035	$15,928	$15,758	$15,845	$15,765	$15,660	$15,660	$15,594	$15,637	$15,694	$189,792

Notes:
(A) Applicable depreciable base for Polk; account 342.81 ($1,561,473)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 3.4%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	(326,042)	(331,159)	(336,276)	(341,393)	(346,510)	(351,627)	(356,744)	(361,861)	(366,978)	(372,095)	(377,212)	(382,329)	(387,446)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,232,688	2,227,571	2,222,454	2,217,337	2,212,220	2,207,103	2,201,986	2,196,869	2,191,752	2,186,635	2,181,518	2,176,401	2,171,284	
6.	Average Net Investment		2,230,130	2,225,013	2,219,896	2,214,779	2,209,662	2,204,545	2,199,428	2,194,311	2,189,194	2,184,077	2,178,960	2,173,843	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		16,203	16,166	16,129	16,092	16,055	16,017	15,980	15,943	15,906	15,869	15,832	15,794	$191,986
	b. Debt Component Grossed Up For Taxes (F)		5,450	5,437	5,425	5,412	5,400	5,387	5,375	5,362	5,350	5,337	5,325	5,312	64,572
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)		26,770	26,720	26,671	26,621	26,572	26,521	26,472	26,422	26,373	26,323	26,274	26,223	317,962
	a. Recoverable Costs Allocated to Energy		26,770	26,720	26,671	26,621	26,572	26,521	26,472	26,422	26,373	26,323	26,274	26,223	317,962
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		26,178	25,992	25,997	25,842	25,586	25,744	25,637	25,485	25,504	25,418	25,505	25,618	308,506
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$26,178	$25,992	$25,997	$25,842	$25,586	$25,744	$25,637	$25,485	$25,504	$25,418	$25,505	$25,618	$308,506

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44 ($2,558,730)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 2.4%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	
	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	$1,649,121	$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	$1,649,121	
3.	Less: Accumulated Depreciation	(161,005)	(165,540)	(170,075)	(174,610)	(179,145)	(183,680)	(188,215)	(192,750)	(197,285)	(201,820)	(206,355)	(210,890)	(215,425)	
4.	CWIP - Non-Interest Bearing	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	367,767	
5.	Net Investment (Lines 2 + 3 + 4)	$1,855,883	1,851,348	1,846,813	1,842,278	1,837,743	1,833,208	1,828,673	1,824,138	1,819,603	1,815,068	1,810,533	1,805,998	1,801,463	
6.	Average Net Investment		1,853,616	1,849,081	1,844,546	1,840,011	1,835,476	1,830,941	1,826,406	1,821,871	1,817,336	1,812,801	1,808,266	1,803,731	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		13,468	13,435	13,402	13,369	13,336	13,303	13,270	13,237	13,204	13,171	13,138	13,105	$159,438
	b. Debt Component Grossed Up For Taxes (F)		4,530	4,519	4,507	4,496	4,485	4,474	4,463	4,452	4,441	4,430	4,419	4,408	53,624
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)		22,533	22,489	22,444	22,400	22,356	22,312	22,268	22,224	22,180	22,136	22,092	22,048	267,482
	a. Recoverable Costs Allocated to Energy		22,533	22,489	22,444	22,400	22,356	22,312	22,268	22,224	22,180	22,136	22,092	22,048	267,482
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		22,035	21,877	21,876	21,744	21,527	21,659	21,566	21,436	21,450	21,375	21,446	21,540	259,531
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)		$22,035	$21,877	$21,876	$21,744	$21,527	$21,659	$21,566	$21,436	$21,450	$21,375	$21,446	$21,540	$259,531

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41 ($1,649,121)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 3.3%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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	(145,088)	(149,175)	(153,262)	(157,349)	(161,436)	(165,523)	(169,610)	(173,697)	(177,784)	(181,871)	(185,958)	(190,045)	(194,132)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,436,799	1,432,712	1,428,625	1,424,538	1,420,451	1,416,364	1,412,277	1,408,190	1,404,103	1,400,016	1,395,929	1,391,842	1,387,755	
6.	Average Net Investment		1,434,756	1,430,669	1,426,582	1,422,495	1,418,408	1,414,321	1,410,234	1,406,147	1,402,060	1,397,973	1,393,886	1,389,799	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		10,424	10,395	10,365	10,335	10,306	10,276	10,246	10,217	10,187	10,157	10,128	10,098	$123,134
	b. Debt Component Grossed Up For Taxes (F)		3,506	3,496	3,486	3,476	3,466	3,456	3,446	3,436	3,426	3,416	3,406	3,396	41,412
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)		18,017	17,978	17,938	17,898	17,859	17,819	17,779	17,740	17,700	17,660	17,621	17,581	213,590
	a. Recoverable Costs Allocated to Energy		18,017	17,978	17,938	17,898	17,859	17,819	17,779	17,740	17,700	17,660	17,621	17,581	213,590
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		17,619	17,489	17,484	17,374	17,196	17,297	17,218	17,111	17,117	17,053	17,105	17,176	207,239
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)		$17,619	$17,489	$17,484	$17,374	$17,196	$17,297	$17,218	$17,111	$17,117	$17,053	$17,105	$17,176	$207,239

Notes:

(A) Applicable depreciable base for Big Bend; account 312.42 ($1,581,887)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 3.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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		$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)	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	
3.	Less: Accumulated Depreciation	(120,266)	(126,071)	(131,876)	(137,681)	(143,486)	(149,291)	(155,096)	(160,901)	(166,706)	(172,511)	(178,316)	(184,121)	(189,926)	
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)	$2,586,241	2,580,436	2,574,631	2,568,826	2,563,021	2,557,216	2,551,411	2,545,606	2,539,801	2,533,996	2,528,191	2,522,386	2,516,581	
6.	Average Net Investment		2,583,339	2,577,534	2,571,729	2,565,924	2,560,119	2,554,314	2,548,509	2,542,704	2,536,899	2,531,094	2,525,289	2,519,484	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		18,770	18,728	18,685	18,643	18,601	18,559	18,517	18,474	18,432	18,390	18,348	18,306	$222,453
	b. Debt Component Grossed Up For Taxes (F)		6,313	6,299	6,284	6,270	6,256	6,242	6,228	6,214	6,199	6,185	6,171	6,157	74,818
8.	Investment Expenses														
	a. Depreciation (C)		5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	69,660
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		30,888	30,832	30,774	30,718	30,662	30,606	30,550	30,493	30,436	30,380	30,324	30,268	366,931
	a. Recoverable Costs Allocated to Energy		30,888	30,832	30,774	30,718	30,662	30,606	30,550	30,493	30,436	30,380	30,324	30,268	366,931
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		30,205	29,993	29,996	29,819	29,524	29,710	29,586	29,412	29,434	29,335	29,437	29,570	356,021
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$30,205	$29,993	$29,996	$29,819	$29,524	$29,710	$29,586	$29,412	$29,434	$29,335	$29,437	$29,570	$356,021

Notes:
(A) Applicable depreciable base for Big Bend; account 312.43 ($1,995,677) and 315.43 ($710,830)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 2.6% and 2.5%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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		$7,027,032	$4,910,234	$1,815,814	$1,552,189	$262,711	$262,710	$0	$0	$0	$0	$0	$0	$15,830,690
	b. Clearings to Plant		0	0	0	0	95,683,666	262,710	0	0	0	0	0	0	$95,946,376
	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)	$72,203,171	$79,230,203	$84,140,437	$85,956,251	$87,508,440	$95,683,666	$95,946,376	$95,946,376	$95,946,376	$95,946,376	$95,946,376	$95,946,376	$95,946,376	
3.	Less: Accumulated Depreciation	0	0	0	0	0	0	(257,135)	(514,993)	(772,851)	(1,030,709)	(1,288,567)	(1,546,425)	(1,804,283)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$72,203,171	79,230,203	84,140,437	85,956,251	87,508,440	95,683,666	95,689,241	95,431,383	95,173,525	94,915,667	94,657,809	94,399,951	94,142,093	
6.	Average Net Investment		75,716,687	81,685,320	85,048,344	86,732,345	91,596,053	95,686,453	95,560,312	95,302,454	95,044,596	94,786,738	94,528,880	94,271,022	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	0	665,506	695,226	694,309	692,436	690,562	688,689	686,815	684,942	$5,498,485
	b. Debt Component Grossed Up For Taxes (F)		0	0	0	0	223,830	233,826	233,518	232,887	232,257	231,627	230,997	230,367	1,849,309
8.	Investment Expenses														
	a. Depreciation (C)		0	0	0	0	0	257,135	257,858	257,858	257,858	257,858	257,858	257,858	1,804,283
	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	889,336	1,186,187	1,185,685	1,183,181	1,180,677	1,178,174	1,175,670	1,173,167	9,152,077
	a. Recoverable Costs Allocated to Energy		0	0	0	0	889,336	1,186,187	1,185,685	1,183,181	1,180,677	1,178,174	1,175,670	1,173,167	9,152,077
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		0	0	0	0	856,340	1,151,450	1,148,283	1,141,240	1,141,792	1,137,646	1,141,270	1,146,111	8,864,132
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13) (G)		$0	$0	$0	$0	$856,340	$1,151,450	$1,148,283	$1,141,240	$1,141,792	$1,137,646	$1,141,270	$1,146,111	$8,864,132

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41 ($86,954,400) and 315.41 ($8,991,976).
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate are 3.3% and 2.5%.
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.
(G) 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 2010 to December 2010

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		$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)	$90,520,503	$90,520,503	$90,520,503	$90,520,503	$90,520,503	$90,520,503	$90,520,503	$90,520,503	$90,520,503	$90,520,503	$90,520,503	$90,520,503	$90,520,503	
3.	Less: Accumulated Depreciation	(933,071)	(1,166,916)	(1,400,761)	(1,634,606)	(1,868,451)	(2,102,296)	(2,336,141)	(2,569,986)	(2,803,831)	(3,037,676)	(3,271,521)	(3,505,366)	(3,739,211)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$89,587,432	89,353,587	89,119,742	88,885,897	88,652,052	88,418,207	88,184,362	87,950,517	87,716,672	87,482,827	87,248,982	87,015,137	86,781,292	
6.	Average Net Investment		89,470,510	89,236,665	89,002,820	88,768,975	88,535,130	88,301,285	88,067,440	87,833,595	87,599,750	87,365,905	87,132,060	86,898,215	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		650,063	648,364	646,665	644,966	643,267	641,568	639,869	638,170	636,471	634,772	633,073	631,373	$7,688,621
	b. Debt Component Grossed Up For Taxes (F)		218,636	218,065	217,493	216,922	216,350	215,779	215,207	214,636	214,065	213,493	212,922	212,350	2,585,918
8.	Investment Expenses														
	a. Depreciation (C)		233,845	233,845	233,845	233,845	233,845	233,845	233,845	233,845	233,845	233,845	233,845	233,845	2,806,140
	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)		1,102,544	1,100,274	1,098,003	1,095,733	1,093,462	1,091,192	1,088,921	1,086,651	1,084,381	1,082,110	1,079,840	1,077,568	13,080,679
	a. Recoverable Costs Allocated to Energy		1,102,544	1,100,274	1,098,003	1,095,733	1,093,462	1,091,192	1,088,921	1,086,651	1,084,381	1,082,110	1,079,840	1,077,568	13,080,679
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		1,078,164	1,070,316	1,070,235	1,063,651	1,052,892	1,059,237	1,054,572	1,048,132	1,048,668	1,044,886	1,048,244	1,052,716	12,691,713
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)		$1,078,164	$1,070,316	$1,070,235	$1,063,651	$1,052,892	$1,059,237	$1,054,572	$1,048,132	$1,048,668	$1,044,886	$1,048,244	$1,052,716	$12,691,713

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42 ($90,520,503)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 3.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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		$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)	$78,709,209	$78,709,209	$78,709,209	$78,709,209	$78,709,209	$78,709,209	$78,709,209	$78,709,209	$78,709,209	$78,709,209	$78,709,209	$78,709,209	$78,709,209	
3.	Less: Accumulated Depreciation	(2,914,986)	(3,081,834)	(3,248,682)	(3,415,530)	(3,582,378)	(3,749,226)	(3,916,074)	(4,082,922)	(4,249,770)	(4,416,618)	(4,583,466)	(4,750,314)	(4,917,162)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$75,794,223	75,627,375	75,460,527	75,293,679	75,126,831	74,959,983	74,793,135	74,626,287	74,459,439	74,292,591	74,125,743	73,958,895	73,792,047	
6.	Average Net Investment		75,710,799	75,543,951	75,377,103	75,210,255	75,043,407	74,876,559	74,709,711	74,542,863	74,376,015	74,209,167	74,042,319	73,875,471	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		550,089	548,877	547,665	546,453	545,240	544,028	542,816	541,604	540,391	539,179	537,967	536,755	$6,521,064
	b. Debt Component Grossed Up For Taxes (E)		185,012	184,604	184,197	183,789	183,381	182,973	182,566	182,158	181,750	181,342	180,935	180,527	2,193,234
8.	Investment Expenses														
	a. Depreciation (C)		166,848	166,848	166,848	166,848	166,848	166,848	166,848	166,848	166,848	166,848	166,848	166,848	2,002,176
	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)		901,949	900,329	898,710	897,090	895,469	893,849	892,230	890,610	888,989	887,369	885,750	884,130	10,716,474
	a. Recoverable Costs Allocated to Energy		901,949	900,329	898,710	897,090	895,469	893,849	892,230	890,610	888,989	887,369	885,750	884,130	10,716,474
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		882,005	875,815	875,982	870,824	862,245	867,673	864,085	859,040	859,711	856,844	859,833	863,740	10,397,797
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)		$882,005	$875,815	$875,982	$870,824	$862,245	$867,673	$864,085	$859,040	$859,711	$856,844	$859,833	$863,740	$10,397,797

Notes:
(A) Applicable depreciable base for Big Bend; account 311.43 ($3,162,013) and 312.43 ($75,547,196)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rates are 1.2% and 2.6%
(D) Line 9a x Line 10
(E) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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)	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	$61,183,337	
3.	Less: Accumulated Depreciation	(3,851,689)	(3,974,056)	(4,096,423)	(4,218,790)	(4,341,157)	(4,463,524)	(4,585,891)	(4,708,258)	(4,830,625)	(4,952,992)	(5,075,359)	(5,197,726)	(5,320,093)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$57,331,648	57,209,281	57,086,914	56,964,547	56,842,180	56,719,813	56,597,446	56,475,079	56,352,712	56,230,345	56,107,978	55,985,611	55,863,244	
6.	Average Net Investment		57,270,465	57,148,098	57,025,731	56,903,364	56,780,997	56,658,630	56,536,263	56,413,896	56,291,529	56,169,162	56,046,795	55,924,428	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		416,108	415,219	414,330	413,441	412,552	411,663	410,774	409,885	408,995	408,106	407,217	406,328	$4,934,618
	b. Debt Component Grossed Up For Taxes (F)		139,950	139,651	139,352	139,053	138,754	138,455	138,156	137,857	137,558	137,259	136,960	136,661	1,659,666
8.	Investment Expenses														
	a. Depreciation (C)		122,367	122,367	122,367	122,367	122,367	122,367	122,367	122,367	122,367	122,367	122,367	122,367	1,468,404
	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)		678,425	677,237	676,049	674,861	673,673	672,485	671,297	670,109	668,920	667,732	666,544	665,356	8,062,688
	a. Recoverable Costs Allocated to Energy		678,425	677,237	676,049	674,861	673,673	672,485	671,297	670,109	668,920	667,732	666,544	665,356	8,062,688
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	-
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		663,424	658,797	658,952	655,102	648,678	652,791	650,121	646,355	646,890	644,763	647,041	650,011	7,822,925
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)		$663,424	$658,797	$658,952	$655,102	$648,678	$652,791	$650,121	$646,355	$646,890	$644,763	$647,041	$650,011	$7,822,925

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44 ($61,183,337)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 2.4%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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		$0	$0	$0	$0	$0	$250,000	$250,000	$500,000	$750,000	$350,000	$200,000	$200,000	$2,500,000
	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)	$11,564,451	$11,564,451	$11,564,451	$11,564,451	$11,564,451	$11,564,451	$11,564,451	$11,564,451	$11,564,451	$11,564,451	$11,564,451	$11,564,451	$11,564,451	
3.	Less: Accumulated Depreciation	(560,953)	(583,239)	(605,525)	(627,811)	(650,097)	(672,383)	(694,669)	(716,955)	(739,241)	(761,527)	(783,813)	(806,099)	(828,385)	
4.	CWIP - Non-Interest Bearing	16,183	16,183	16,183	16,183	16,183	16,183	266,183	516,183	1,016,183	1,766,183	2,116,183	2,316,183	2,516,183	
5.	Net Investment (Lines 2 + 3 + 4)	$11,019,681	10,997,395	10,975,109	10,952,823	10,930,537	10,908,251	11,135,965	11,363,679	11,841,393	12,569,107	12,896,821	13,074,535	13,252,249	
6.	Average Net Investment		11,008,538	10,986,252	10,963,966	10,941,680	10,919,394	11,022,108	11,249,822	11,602,536	12,205,250	12,732,964	12,985,678	13,163,392	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		79,984	79,822	79,661	79,499	79,337	80,083	81,737	84,300	88,679	92,513	94,350	95,641	$1,015,606
	b. Debt Component Grossed Up For Taxes (F)		26,901	26,847	26,792	26,738	26,683	26,934	27,491	28,353	29,826	31,115	31,733	32,167	341,580
8.	Investment Expenses														
	a. Depreciation (C)		22,286	22,286	22,286	22,286	22,286	22,286	22,286	22,286	22,286	22,286	22,286	22,286	267,432
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		129,171	128,955	128,739	128,523	128,306	129,303	131,514	134,939	140,791	145,914	148,369	150,094	1,624,618
	a. Recoverable Costs Allocated to Energy		129,171	128,955	128,739	128,523	128,306	129,303	131,514	134,939	140,791	145,914	148,369	150,094	1,624,618
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		126,315	125,444	125,483	124,760	123,546	125,516	127,365	130,156	136,154	140,895	144,028	146,632	1,576,294
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$126,315	$125,444	$125,483	$124,760	$123,546	$125,516	$127,365	$130,156	$136,154	$140,895	$144,028	$146,632	$1,576,294

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44 ($1,456,209) and 312.45 ($10,108,242)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 2.4% and 2.3%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

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		$0	$0	$20,000	$0	$0	$0	$0	$0	$0	$0	$0	$0	$20,000
	b. Clearings to Plant		0	0	20,000	0	0	0	0	0	0	0	0	0	$20,000
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,153,186	$1,153,186	$1,153,186	$1,173,186	$1,173,186	$1,173,186	$1,173,186	$1,173,186	$1,173,186	$1,173,186	$1,173,186	$1,173,186	$1,173,186	
3.	Less: Accumulated Depreciation	(22,605)	(2,883)	(5,766)	(8,649)	(11,582)	(14,515)	(17,448)	(20,381)	(23,314)	(26,247)	(29,180)	(32,113)	(35,046)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,130,581	1,150,303	1,147,420	1,164,537	1,161,604	1,158,671	1,155,738	1,152,805	1,149,872	1,146,939	1,144,006	1,141,073	1,138,140	
6.	Average Net Investment		1,140,442	1,148,862	1,155,979	1,163,071	1,160,138	1,157,205	1,154,272	1,151,339	1,148,406	1,145,473	1,142,540	1,139,607	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		8,286	8,347	8,399	8,450	8,429	8,408	8,387	8,365	8,344	8,323	8,301	8,280	$100,319
	b. Debt Component Grossed Up For Taxes (F)		2,787	2,807	2,825	2,842	2,835	2,828	2,821	2,813	2,806	2,799	2,792	2,785	33,740
8.	Investment Expenses														
	a. Depreciation (C)		2,883	2,883	2,883	2,933	2,933	2,933	2,933	2,933	2,933	2,933	2,933	2,933	35,046
	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)		13,956	14,037	14,107	14,225	14,197	14,169	14,141	14,111	14,083	14,055	14,026	13,998	169,105
	a. Recoverable Costs Allocated to Energy		13,956	14,037	14,107	14,225	14,197	14,169	14,141	14,111	14,083	14,055	14,026	13,998	169,105
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		13,647	13,655	13,750	13,809	13,670	13,754	13,695	13,611	13,619	13,572	13,616	13,675	164,073
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)		$13,647	$13,655	$13,750	$13,809	$13,670	$13,754	$13,695	$13,611	$13,619	$13,572	$13,616	$13,675	$164,073

Notes:
(A) Applicable depreciable base for Big Bend and Polk; accounts 312.41, 312.43, 312.44, 315.40 ($1,173,186) and 345.81
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Applicable depreciation rate is 3.3%, 2.6%, 2.4%, 3.0%, and 3.1%
(D) Line 9a x Line 10
(E) Line 9b x Line 11
(F) Line 6 x 2.9324% x 1/12.

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 to December 2010

For Project: SO_2 Emissions Allowances
(in Dollars)

Line Description	Beginning of Period Amount	Projected January 10	Projected February 10	Projected March 10	Projected April 10	Projected May 10	Projected June 10	Projected July 10	Projected August 10	Projected September 10	Projected October 10	Projected November 10	Projected December 10	End of Period Total
1. Investments														
a. Purchases/Transfers		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	0
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	(40,594)	(40,314)	(40,012)	(39,771)	(39,504)	(39,191)	(38,848)	(38,490)	(38,132)	(37,788)	(37,484)	(37,121)	(36,757)	
3. Total Working Capital Balance	($40,594)	($40,314)	($40,012)	($39,771)	($39,504)	($39,191)	($38,848)	($38,490)	($38,132)	($37,788)	($37,484)	($37,121)	($36,757)	
4. Average Net Working Capital Balance		($40,454)	($40,163)	($39,891)	($39,638)	($39,348)	($39,019)	($38,669)	($38,311)	($37,960)	($37,636)	($37,303)	($36,939)	
5. Return on Average Net Working Capital Balance														
a. Equity Component Grossed Up For Taxes (A)		(294)	(292)	(290)	(288)	(286)	(283)	(281)	(278)	(276)	(273)	(271)	(268)	($3,380)
b. b. Debt Component Grossed Up For Taxes (E)		(99)	(98)	(97)	(97)	(96)	(95)	(94)	(94)	(93)	(92)	(91)	(90)	($1,136)
6. Total Return Component		(393)	(390)	(387)	(385)	(382)	(378)	(375)	(372)	(369)	(365)	(362)	(358)	($4,516)
7. Expenses:														
a. Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
b. Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
c. SO_2 Allowance Expense		46,720	42,098	46,759	47,134	48,787	47,057	48,742	48,742	47,056	48,796	45,037	46,636	563,564
8. Net Expenses (B)		46,720	42,098	46,759	47,134	48,787	47,057	48,742	48,742	47,056	48,796	45,037	46,636	563,564
9. Total System Recoverable Expenses (Lines 6 + 7)		$46,327	$41,708	$46,372	$46,749	$48,405	$46,679	$48,367	$48,370	$46,687	$48,431	$44,675	$46,278	$559,048
a. Recoverable Costs Allocated to Energy		46,327	41,708	46,372	46,749	48,405	46,679	48,367	48,370	46,687	48,431	44,675	46,278	559,048
b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10. Energy Jurisdictional Factor		0.9778879	0.9727724	0.9747108	0.9707213	0.9628980	0.9707152	0.9684555	0.9645523	0.9670659	0.9656009	0.9707400	0.9769374	0.9702548
11. Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735
12. Retail Energy-Related Recoverable Costs (C)		45,303	40,572	45,199	45,380	46,609	45,312	46,841	46,655	45,149	46,765	43,368	45,211	542,364
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)		$45,303	$40,572	$45,199	$45,380	$46,609	$45,312	$46,841	$46,655	$45,149	$46,765	$43,368	$45,211	$542,364

Notes:
(A) Line 4 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(B) Line 8 is reported on Schedule 2P
(C) Line 9a x Line 10
(D) Line 9b x Line 11
(E) Line 4 x 2.9324% x 1/12.

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Project Title: Big Bend Unit 3 Flue Gas Desulfurization Integration

Project Description:

This project involved the integration of Big Bend Unit 3 flue gases into the Big Bend Unit 4 Flue Gas Desulfurization ("FGD") system. The integration was accomplished by installing interconnecting ductwork between Unit 3 precipitator outlet ducts and the Unit 4 FGD inlet duct. The Unit 4 FGD outlet duct was interconnected with the Unit 3 chimney via new ductwork and a new stack breaching. New ductwork, linings, isolation dampers, support steel, and stack annulus pressurization fans were procured and installed. Modifications to the materials handling systems and controls were also necessary.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2009 through December 2009, is $786,289 compared to the original projection of $786,042, resulting in an insignificant variance.

The actual/estimated O&M expense for the period January 2009 through December 2009 is $3,351,790 compared to the original projection of $3,658,000 representing a variance of 8.4 percent. This variance is due to a lower cost of consumables for gypsum production as well as a decrease in maintenance costs.

Progress Summary: The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2010 through December 2010, is expected to be $764,341.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $4,241,800.

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Project Title: Big Bend Units 1 & 2 Flue Gas Conditioning

Project Description:

The existing electrostatic precipitators were not designed for the range of fuels needed for compliance with the Clean Air Act Amendments ("CAAA"). Flue gas conditioning was required to assure operation of the generating units in accordance with applicable permits and regulations. This equipment is still required to ensure compliance with the CAAA in the event the FGD system on Units 1 & 2 is not operating.

The project involved the addition of molten sulfur unloading, storage and conveying to sulfur burners and catalytic converters where SO_2 is converted to SO_3. The control and injection system then injects this into the ductwork ahead of the electrostatic precipitators.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2009 through December 2009 is $440,808 compared to the original projection of $440,693, resulting in an insignificant variance.

The actual/estimated O&M expense for this project for the period January 2009 through December 2009 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 2010 through December 2010 is projected to be $422,124.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $0.

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Project Title: Big Bend Unit 4 Continuous Emissions Monitors

Project Description:

Continuous emissions monitors (CEMs) were installed on the flue gas inlet and outlet of Big Bend Unit 4 to monitor compliance with the CAAA requirements. The monitors are capable of measuring, recording and electronically reporting SO_2, NO_x and volumetric gas flow out of the stack. The project consisted of monitors, a CEM building, the CEMs control and power cables to supply a complete system.

40 CFR Part 75 includes the general requirements for the installation, certification, operation and maintenance of CEMs and specific requirements for the monitoring of pollutants, opacity and volumetric flow. These regulations are very comprehensive and specific as to the requirements for CEMs, and in essence, they define the components needed and their configuration.

Project Accomplishment:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2009 through December 2009 is $80,611 compared to the original projection of $80,584, resulting in an insignificant variance.

Progress Summary: The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2010 through December 2010 is projected to be $78,510.

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Project Title: Big Bend Unit 1 Classifier Replacement

Project Description:

The boiler modifications at Big Bend Unit 1 are part of Tampa Electric's NO_X compliance strategy for Phase II of the CAAA. The classifier replacements will optimize coal fineness by providing a 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 2009 through December 2009 is $138,835 compared to the original projection of $138,796, resulting in an insignificant variance.

Progress Summary: The project was placed in-service December 1998.

Projections: Estimated depreciation plus return for the period January 2010 through December 2010 is projected to be $133,795.

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Project Title: Big Bend Unit 2 Classifier Replacement

Project Description:

The boiler modifications at Big Bend Unit 2 are part of Tampa Electric's NO_X compliance strategy for Phase II of the CAAA. The classifier replacements will optimize coal fineness by providing a more uniform particle size. This finer classification, combined with the equalized distribution of coal to outlet pipes and furnaces, will enable a uniform, staged combustion. As a result, firing systems will operate at lower NO_X levels.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2009 through December 2009 is $100,518 compared to the original projection of $100,489 representing no variance.

Progress Summary: The project was placed in-service May 1998.

Projections: Estimated depreciation plus return for the period January 2010 through December 2010 is projected to be $96,974.

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Project Title: Big Bend Units 1 & 2 FGD

Project Description:

The Big Bend Units 1 & 2 FGD system consists of equipment capable of removing SO_2 from the flue gas generated by the combustion of coal. The FGD was installed in order to comply with Phase II of the CAAA. Compliance with Phase II is required by January 1, 2000. The CAAA impose SO_2 emission limits on existing steam electric units with an output capacity of greater than 25 megawatts and all new utility units. Tampa Electric conducted an exhaustive analysis of options to comply with Phase II of the CAAA that culminated in the selection of the FGD project to serve Big Bend Units 1 & 2.

In Docket No. 980693-EI, Order No. PSC-99-0075-FOF-EI, issued January 11, 1999, the Commission found that the FGD project was the most cost-effective alternative for compliance with the SO_2 requirements of Phase II of the CAAA.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2009 through December 2009 is $8,921,117 compared to the original projection of $8,960,005, representing an insignificant variance.

The actual/estimated O&M expense for the period January 2009 through December 2009 is $8,386,537 as compared to the original estimate of $7,482,800 resulting in a variance of 12.1 percent. This variance is primarily due to the re-allocation of 2008 maintenance activities with the scheduled outages for 2009.

Progress Summary: The project was placed in-service in December 1999.

Projections: Estimated depreciation plus return for the period January 2010 through December 2010 is expected to be $8,823,552.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $7,443,300.

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Project Title: Big Bend Section 114 Mercury Testing Platform

Project Description:

The Mercury Emissions Information Collection Effort is mandated by the EPA. The EPA asserts that Section 114 of the CAAA grants to the EPA the authority to request the collection of information necessary for it to study whether it is appropriate and necessary to develop performance or emission standards for electric utility steam generating units.

In a letter dated November 25, 1998, Tampa Electric was notified by the EPA that, pursuant to Section 114 of the CAAA, the company was required to periodically sample and analyze coal shipments for mercury and chlorine content during the period January 1, 1999 through December 31, 1999.

In addition to coal sampling, stack testing and analyses are also required. Tampa Electric received a second letter from EPA, dated March 11, 1999, requiring Tampa Electric to perform 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 2009 through December 2009, is $13,584 compared to the original projection of $13,577, 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 2010 through December 2010 is expected to be $13,303.

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Project Title: Big Bend FGD Optimization and Utilization

Project Description:

In order to meet the requirements of the FDEP Consent Final 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 2009 through December 2009 is $2,533,290 compared to the original projection of $2,532,454, representing an insignificant variance.

Progress Summary: The project was placed in-service in January 2002.

Projections: Estimated depreciation plus return for the period January 2010 through December 2010 is expected to be $2,475,526.

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Project Title: Big Bend PM Minimization and Monitoring

Project Description:

In order to meet the requirements of the FDEP Consent Final 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 2009 through December 2009 is $1,086,037 as compared to the original projection of $1,124,629 resulting in an insignificant variance.

The actual/estimated O&M expense the period January 2009 through December 2009 is $467,907 as compared to the original projection of $455,000, representing an insignificant variance.

Progress Summary: This project was placed in-service July 2005.

Projections: Estimated depreciation plus return for the period January 2010 through December 2010 is expected to be $1,064,831.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $470,000.

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Project Title: Big Bend NO_x Emissions Reduction

Project Description:

In order to meet the requirements of the FDEP Consent Final 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 2009 through December 2009 is $802,153 as compared to the original projection of $793,965 resulting in an insignificant variance.

The actual/estimated O&M expense the period January 2009 through December 2009 is $361,773 as compared to the original projection of $358,000, representing an insignificant variance.

Progress Summary: The project was placed in-service January 2006.

Projections: Estimated depreciation plus return for the period January 2010 through December 2010 is expected to be $804,002.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $396,000.

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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 2009 through December 2009 is $54,575 compared to the original projection of $54,560, representing an insignificant variance.

Progress Summary: The project was placed in-service October 1998.

Projections: Estimated depreciation plus return for the period January 2010 through December 2010 is projected to be $53,079.

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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 2009 through December 2009 is $89,767 compared to the original projection of $89,738, representing an insignificant variance.

Progress Summary: The project was placed in-service December 1998.

Projections: Estimated depreciation plus return for the period January 2010 through December 2010 is projected to be $87,302.

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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 2009 through December 2009, is $5,862 compared to the original projection of $5,859, 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 2010 through December 2010 is projected to be $5,667.

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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 2009 through December 2009 is $9,215 compared to the original projection of $9,211, 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 2010 through December 2010 is projected to be $8,899.

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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 2009 through December 2009 is ($5,037) compared to the original projection of ($1,669) representing a 201.8 percent variance. The variance is due to the sale of SO_2 allowances originally projected to occur in 2009 but transpired throughout 2008.

The actual/estimated O&M for the period January 2009 through December 2009 is $377,496 compared to the original projection of ($12,123,542) representing a variance of 103.1 percent. The significant variance is driven by the revenue shortfall precipitated by a significant market decline in SO_2 emission allowance prices.

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 2010 through December 2010 is projected to be ($4,516).

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $563,564.

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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 2009 through December 2009 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 2010 through December 2010 are projected to be $34,500.

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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 2009 through December 2009 is $194,066 compared to the original projection of $50,000, which represents a variance of 288.1 percent. The variance is due to the delayed invoicing from contractors.

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 2010.

Projections: Estimated O&M costs for the period January 2010 through December 2010 are projected to be $30,000.

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Project Title: Polk NO_x Emissions Reduction

Project Description:

This project is designed to meet a lower NO_x emissions limit established by the FDEP for Polk Unit 1 by July 1, 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 2009 through December 2009 is $201,759 as compared to the original projection of $201,701, representing an insignificant variance.

The actual/estimated O&M for the period January 2009 through December 2009 is $49,036 compared to the original projection of $75,000, which represents a variance of 34.6 percent. The variance is due to the need for less maintenance than originally anticipated.

Progress Summary: The project was placed in-service January 2005.

Project Projections: Estimated depreciation plus return for the period January 2010 through December 2010 is projected to be $195,609.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $50,000.

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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 2009 through December 2009 is $122,057 compared to the original projection of $82,000 resulting in a variance of 48.9 percent. The variance is due to the increase in price and consumption of ammonia.

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 2010 through December 2010 are projected to be $114,000.

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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 2009 through December 2009 is $325,057 compared to the original projection of $324,949, resulting in an insignificant variance.

The actual/estimated O&M for the period January 2009 through December 2009 is $25,718 compared to the original projection of $50,000, which represents a variance of 48.6 percent. This variance is due to a correction made to the General Ledger for a cost inadvertently booked against the project.

Progress Summary: The project was placed in-service November 2004.

Projections: Estimated depreciation plus return for the period January 2010 through December 2010 is projected to be $317,962.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $62,000.

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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 2010 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 2009 through December 2009 is $273,776 compared to the original projection of $279,459, resulting in an insignificant variance.

The actual/estimated O&M for the period January 2009 through December 2009 is $77,000 compared to the original projection of $77,000 representing no variance.

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 2010 through December 2010 is projected to be $267,482.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $75,000.

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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 2010 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 2009 through December 2009 is $219,267 compared to the original projection of $219,196, resulting in an insignificant variance.

The actual/estimated O&M for the period January 2009 through December 2009 is $67,722 compared to the original projection of $77,000, which represents a variance of 12.0 percent. 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 2010 through December 2010 is projected to be $213,590.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $31,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 3 Pre-SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2010 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 2009 through December 2009 is $378,117 compared to the original projection of $279,459, resulting in an insignificant variance.

No O&M costs are anticipated for the period January 2009 through December 2009.

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 2010 through December 2010 is projected to be $366,931.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $31,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
Description and Progress Report for
Environmental Compliance Activities and Projects

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 2009 through December 2009 is $47,240 compared to the original projection of $150,000, which represents a variance of 68.5 percent. This variance is due to the decrease in contractor costs to complete the impingement study reports.

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 2010 through December 2010 are projected to be $60,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
Description and Progress Report for
Environmental Compliance Activities and Projects

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 2010 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 2010 through December 2010 is projected to be $9,152,077.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $1,001,600.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
Description and Progress Report for
Environmental Compliance Activities and Projects

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 2010 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 April 2010.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2009 through December 2009 is $4,884,018 compared to the original projection of $8,618,125, which represents variance of 43.3 percent. This variance is due to the delay in commercial operation.

The actual/estimated O&M for the period January 2009 through December 2009 is $728,900 compared to the original projection of $1,807,700 representing a variance of 59.7 percent. The variance is due to the delay in commercial operation.

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 2010 through December 2010 is projected to be $13,080,679.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $1,668,100.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
Description and Progress Report for
Environmental Compliance Activities and Projects

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 2010 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 2010.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2009 through December 2009 is $10,944,895 compared to the original projection of $11,145,102, resulting in an insignificant variance.

The actual/estimated O&M for the period January 2009 through December 2009 is $1,437,288 compared to the original projection of $2,204,900 representing a variance of 34.8 percent. The variance is due to less ammonia used than originally anticipated.

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 2010 through December 2010 is projected to be $10,716,474.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $1,668,100.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 4 SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2010 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 2010.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2009 through December 2009 is $8,232,257 compared to the original projection of $8,232,074, resulting in an insignificant variance.

The actual/estimated O&M for the period January 2009 through December 2009 is $678,922 compared to the original projection of $1,252,800 representing a variance of 45.8 percent. The variance is due to 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 2010 through December 2010 is projected to be $8,062,688.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $778,700.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
Description and Progress Report for
Environmental Compliance Activities and Projects

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 2009 through December 2009 is $115,846 compared to the original projection of $114,000, resulting in an insignificant variance.

Progress Summary: 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.

Projections: Estimated O&M costs for the period January 2010 through December 2010 are projected to be $50,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
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 2009 through December 2009 is $1,566,595 compared to the original projection of $1,587,494, resulting in an insignificant variance.

Progress Summary: 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.

Projections: Estimated depreciation plus return for the period January 2010 through December 2010 is projected to be $1,624,618.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2010 through December 2010
Description and Progress Report for
Environmental Compliance Activities and Projects

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 2009 through December 2009 is $151,020 compared to the original projection of $110,652, which represents a variance of 36.5 percent. The variance is due to the installation of the equipment to collect baseline data in preparation for rule changes.

Progress Summary: A petition was filed on August 30, 2006 seeking Commission approval of cost recovery through the ECRC for the new CAMR program.

Projections: Estimated depreciation plus return for the period January 2010 through December 2010 is projected to be $169,105.

Estimated O&M costs for the period January 2010 through December 2010 are projected to be $8,000.

Form 42 - 6P

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2010 to December 2010

Rate Class	(1) Average 12 CP Load Factor at Meter (%)	(2) Projected Sales at Meter (MWh)	(3) Effective Sales at Secondary Level (MWh)	(4) Projected Avg 12 CP at Meter (MW)	(5) Demand Loss Expansion Factor	(6) Energy Loss Expansion Factor	(7) Projected Sales at Generation (MWh)	(8) Projected Avg 12 CP at Generation (MW)	(9) Percentage of MWh Sales at Generation (%)	(10) Percentage of 12 CP Demand at Generation (%)	(11) 12 CP & 25% Allocation Factor (%)
RS	52.81%	8,824,328	8,824,328	1,908	1.08536	1.05482	9,308,101	2,070	46.17%	54.81%	52.65%
GS, TS	54.51%	1,030,757	1,030,757	216	1.08536	1.05482	1,087,266	234	5.39%	6.20%	6.00%
GSD, SBF	74.30%	8,039,231	8,026,251	1,204	1.08085	1.05106	8,449,676	1,302	41.92%	34.47%	36.33%
IS	75.80%	1,061,694	1,043,681	160	1.03968	1.02124	1,084,239	166	5.38%	4.40%	4.65%
LS1	498.93%	218,062	218,062	5	1.08536	1.05482	230,017	5	1.14%	0.13%	0.38%
TOTAL *		19,174,072	19,143,079	3,493			20,159,299	3,777	100.00%	100.00%	100.00%

Notes: (1) Average 12 CP load factor based on 2009 projected calendar data
(2) Projected MWh sales for the period January 2010 to December 2010
(3) Effective sales at secondary level for the period January 2010 to December 2010.
(4) Based on 12 months average CP at meter
(5) Based on 2009 proposed load research data
(6) Average 12 CP load factor based on 2009 proposed load research data
(7) Projected MWh sales for the period January 2010 to December 2010
(8) Column 4 x Column 5
(9) Based on 2009 proposed load research data
(10) Column 8 / Total Column 8
(11) Column 9 x 0.25 + Column 10 x 0.75

* Totals on this schedule may not foot due to rounding

DOCKET NO. 090007-EI
ECRC 2010 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 6

Form 42 - 7P
REVISED 10/19/09

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2010 to December 2010

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	**(8)**
Rate Class	Percentage of MWh Sales at Generation (%)	12 CP & 25% Allocation Factor (%)	Energy-Related Costs ($)	Demand-Related Costs ($)	Total Environmental Costs ($)	Projected Sales at Meter (MWh)	Effective Sales at Secondary Level (MWh)	**Environmental Cost Recovery Factors (¢/kWh)**
RS	46.170%	52.65%	42,648,484	274,890	42,923,374	8,824,328	8,824,328	**0.486**
GS, TS	5.390%	6.00%	4,978,890	31,313	5,010,203	1,030,757	1,030,757	**0.486**
GSD, SBF	41.920%	36.33%	38,722,644	189,695	38,912,339	8,039,231	8,026,251	
Secondary								**0.485**
Primary								**0.480**
Transmission								**0.475**
IS	5.380%	4.65%	4,969,652	24,252	4,993,904	1,061,694	1,043,681	
Secondary								**0.478**
Primary								**0.474**
Transmission								**0.469**
LS1	1.140%	0.38%	1,053,049	1,997	1,055,046	218,062	218,062	**0.484**
TOTAL *	100.00%	100.00%	92,372,719	522,109	92,894,828	19,174,072	19,143,079	**0.485**

* Totals on this schedule may not foot due to rounding

Notes:
(1) From Form 42-6P, Column 9
(2) From Form 42-6P, Column 11
(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) From Form 42-6P, Column 3
(8) Column 5 / Column 7 x 100

Exhibit to the Testimony of James O. Vick

Exhibit (JOV-1)_______

Enclosed Documentation	Page
Plant Smith Consumptive Use Permit	1
NWFWMD correspondence to Gulf Power dated October 20, 2008	7
Federal Register Notice of Agency Information Collection Request dated July 2, 2009	8

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 31
COMPANY Gulf Power Company (Direct)
WITNESS J. O. Vick (JOV-1)
DATE 11/02/09

Northwest Florida Water Management District

152 Water Management Drive, Havana, Florida 32333-4712
(U.S. Highway 90, 10 miles west of Tallahassee)
(850) 539-5999 (Fax) 539-2777

Douglas E. Barr
Executive Director

December 4, 2006

Gulf Power, Inc.
Lansing Smith Electric Generating Plant
One Energy Place
Pensacola, FL 32520-0328

NOTICE OF AGENCY ACTION
Individual Water Use Permit No. 19850073
Consumptive Use Permit Application No. I 06771

Dear Permitee:

Your Individual Water Use Permit was approved by the Governing Board of the Northwest Florida Water Management District at a public hearing on November 30, 2006. The permit issued is subject to the terms and conditions set forth in the enclosed permit document. As you are legally responsible for compliance with the conditions of the permit please read the document thoroughly. Pay close attention to any condition(s) of the permit which require the one-time or periodic submittal of information to the District. Non-compliance may require the District to initiate enforcement action, including the possible assessment of administrative fines. Please designate an individual as the contact person for compliance. This can be done by sending the person's name, address, phone number and email address in hard-copy to the above address or via email (compliance@nwfwmd.state.fl.us).

If the property where the withdrawal facility is located changes ownership, the permit must be transferred. A permit transfer request must be made on NWFWMD Form A2-F (http://www.nwfwmd.state.fl.us/permits/forms/permit_transfer.pdf) and approved by the Executive Director. If the permit is not transferred you may remain responsible for compliance with the conditions of the permit.

If you have any questions concerning the permit document or if the District can be of any other service, please let us know.

Sincerely,

Angela Chelette, Chief
Bureau of Ground Water Regulation
Division of Resource Regulation

Enclosure
cc: Richard M. Markey

NORTHWEST FLORIDA WATER MANAGEMENT DISTRICT
INDIVIDUAL WATER USE PERMIT

(NWFWMD Form No. A2-E)

Permit granted to:	Permit No.: 19850073 Renewal/Modification
Gulf Power Company Lansing Smith Electric Generating Plant One Energy Place Pensacola, Florida 32520-0328 (Legal Name and Address)	Date Permit Granted: November 30, 2006 Permit Expires On: December 1, 2011 Source Classification: Floridan Aquifer, North Bay, Recycled Water Use Classification: Power Generation, Public Supply, Industrial Uses
County: Bay Area: B	Location: Section ____ 1/4 Section ____
Application No.: I06771	Township 2 South Range 14, 15 West

Terms and standard conditions of this Permit are as follows:

1. That all statements in the application and in supporting data are true and accurate and based upon the best information available, and that all conditions set forth herein will be complied with. If any of the statements in the application and in the supporting data are found to be untrue and inaccurate, or if the Permittee fails to comply with all of the conditions set forth herein, then this Permit shall be revoked as provided by Chapter 373.243, Florida Statutes.

2. This Permit is predicated upon the assertion by the Permittee that the use of water applied for and granted is and continues to be a reasonable and beneficial use as defined in Section 373.019(4), Florida Statutes, is and continues to be consistent with the public interest, and will not interfere with any legal use of water existing on the date this Permit is granted.

3. This Permit is conditioned on the Permittee having obtained or obtaining all other necessary permit(s) to construct, operate and certify withdrawal facilities and the operation of water system.

4. This Permit is issued to the Permittee contingent upon continued ownership, lease or other present control of property rights in underlying, overlying, or adjacent lands. This Permit may be assigned to a subsequent owner as provided by Chapter 40A-2.351, Florida Administrative Code, and the acceptance by the transferee of all terms and conditions of the Permit.

19850073/106771

5. This Permit authorizes the Permittee to make a combined average annual withdrawal of **275,200,000*** gallons of water per day, a maximum combined withdrawal of **276,160,000**** gallons during a single day, and a combined monthly withdrawal of **8,531,200,000***** gallons. Withdrawals for the individual facilities are authorized as shown in the table below in paragraph six. However, the total combined amount of water withdrawn by all facilities listed in paragraph six shall not exceed the amounts identified above.

6. *Individual Withdrawal Facility Authorization*

WITHDRAWAL POINT ID NO.	LOCATION SEC,TWN,RNG	GALLONS/DAY AVERAGE	GALLONS/DAY MAXIMUM
LSGP #1 (AAA6592)	Sec. 36, T2S, R15W		720,000
LSGP #2 (AAA6591)	Sec. 36, T2S, R15W		720,000
LSGP #3 (AAA6590)	Sec. 36, T2S, R15W		Abandoned
LSGP #4 (AAD3491)	Sec. 35, T2S, R15W		720,000
LSGP #5 (AAE0186)	Sec. 19, T2S, R15W		720,000
LSGP #6 (To Be Assigned)	Sec. 17, T2S, R14W		720,000 Proposed
LOSP 1A/NB	Sec. 36, T2S, R15W		68,256,000
LOSP 1B/NB	Sec. 36, T2S, R15W		68,256,000
LOSP 2A/NB	Sec. 36, T2S, R15W		68,256,000
LOSP 2B/NB	Sec. 36, T2S, R15W		68,256,000

* 1,200,000 Ground Water - 274,000,000 Surface Water
** 2,160,000 Ground Water - 274,000,000 Surface Water
*** 37,200,000 Ground Water - 8,494,000,000 Surface Water

7. The use of the permitted water withdrawal is restricted to the use classification set forth by the Permit. Any change in the use of said water shall require a modification of this Permit.

8. The District's staff, upon proper identification, will have permission to enter, inspect and observe permitted and related facilities in order to determine compliance with the approved plans, specifications and conditions of this Permit.

9. The District's staff, upon providing prior notice and proper identification, may request permission to collect water samples for analysis, measure static and/or pumping water levels and collect any other information deemed necessary to protect the water resources of the area.

10. The District reserves the right, at a future date, to require the Permittee to submit pumpage records for any or all withdrawal point(s) covered by this Permit.

11. Permittee shall mitigate any significant adverse impact caused by withdrawals permitted herein on the resource and legal water withdrawals and uses, and on adjacent land use, which existed at the time of permit application. The District reserves the right to curtail permitted withdrawal rates if the withdrawal causes significant adverse impact on the resource and legal uses of water, or adjacent land use, which existed at the time of permit application.

12. Permittee shall not cause significant saline water intrusion or increased chloride levels. The District reserves the right to curtail permitted withdrawal rates if withdrawals cause significant saline water intrusion or increased chloride levels.

13. The District, pursuant to Section 373.042, Florida Statutes, at a future date, may establish minimum and/or management water levels in the aquifer, aquifers, or surface water hydrologically associated with the permitted withdrawals; these water levels may require the Permittee to limit withdrawal from these water sources at times when water levels are below established levels.

14. Nothing in this Permit should be construed to limit the authority of the Northwest Florida Water Management District to declare water shortages and issue orders pursuant to Section 373.175, Florida Statutes, or to formulate and implement a plan during periods of water shortage pursuant to Section 373.246, Florida Statutes, or to declare Water Resource Caution Areas pursuant to Chapters 40A-2.801, and 62-40.41, Florida Administrative Code

    (a) In the event of a declared water shortage, water withdrawal reductions shall be made as ordered by the District.

    (b) In the event of a declared water shortage or an area as a Water Resource Caution Area, the District may alter, modify or inactivate all or parts of this permit.

15. The Permittee shall properly plug and abandon any well determined unsuitable for its intended use, not properly operated and maintained, or removed from service. The well(s) shall be plugged and abandoned to District Standards in accordance with Section 40A-3.531, Florida Administrative Code.

16. Any Specific Permit Condition(s) enumerated in Attachment A are herein made a part of this Permit.

Authorized Signature
Northwest Florida Water Management District

ATTACHMENT
Gulf Power Company
Lansing Smith Electric Generating Plant

Individual Water Use Permit No. 19850073
Individual Water Use Application No. I06771

1. The Permittee shall include the Individual Water Use Permit number and the well's Florida Unique Identification Number when submitting reports or otherwise corresponding with the District.

2. The Permittee shall not exceed ground water withdrawal amounts of an annual average daily amount of 1.2 million gallons, a maximum daily amount of 2.16 million gallons, and a maximum monthly amount of 37.2 million gallons.

3. The Permittee shall not exceed surface water withdrawal amounts of an annual average daily amount of 274 million gallons, a maximum daily amount of 274 million gallons and a maximum monthly amount of 8,494 million gallons.

4. The Permittee shall record the data required on the Water Use Summary Reporting Form, NWFWMD A2-I, and submit copies to the District by January 31 of each year. The withdrawals shall be reported separately by source (ground water, surface, and reclaimed). The ground and surface water withdrawals shall also be provided as an aggregate. The Permittee, if preferred, may submit the report electronically by downloading the correct form from the District website, filling it out properly, and e-mailing it to compliance@nwfwmd.state.fl.us. The next report is due January 31, 2007.

5. The Permittee, by January 31, April 30, July 31, and October 31 of each year, shall report the following information as specified below:

   a. Water quality results from tests conducted on each production well of the system during the first two weeks of the months of January, April, July, and October as appropriate to the reporting period. The water quality analysis shall test for the following chemical concentrations: chloride, sodium, sulfate, bicarbonate, carbonate, calcium, magnesium, potassium, and total dissolved solids. Prior to sampling, the Permittee shall purge approximately three to five well volumes from each well, and shall report with each set of test results, the duration of purging, purge volume, and purge rates used.

   b. Static water level data for each production well as recorded during the first two weeks of January, April, July, and October as appropriate to the reporting period. The water level data shall be referenced to mean sea level.

The next water use, water quality and water level reports are due by January 31, 2007.

19850073-006771

6. The Permittee shall continue to return approximately 95 percent or more of the surface water withdrawn.

7. The Permittee, at the time of construction, shall install an in-line totaling flow meter at the well head of proposed well LSGP #6. The Permittee shall maintain in working order in-line totaling flow meters on all other ground water wells.

8. The Permittee shall not exceed a withdrawal rate of 2,000 gallons per minute from the Floridan aquifer. The Permittee, at the time that LSGP #6 is operational, shall implement the pumping scenario identified in the ground water modeling analysis whereby LSGP #4, LSGP #5, and LSGP #6 are operated as primary wells and LSGP #1 and #2 are operated as backup and emergency supply wells.

9. The Permittee shall develop a plan to continue and expand implementation of water conservation and efficiency measures at the plant. The findings of the plan, along with a timetable for implementation, shall be submitted to the District no later than July 31, 2009.

10. The Permittee shall mitigate impacts attributable to the authorized withdrawal that interfere with users of water in the vicinity of Gulf Power's wells. The Permittee shall report the occurrence of any such impacts to the District and shall identify the mitigation action undertaken to address the impacts.

Northwest Florida Water Management District

152 Water Management Drive, Havana, Florida 32333-4712
(U.S. Highway 90, 10 miles west of Tallahassee)

(850) 539-5999 • (Fax) 539-2777

Douglas E. Barr
Executive Director

October 20, 2008

Mr. Mike Markey
Gulf Power Company
One Energy Place
Pensacola, Florida 32520-0328

RE: Individual Water Use Permit No. 19850073
Specific Condition No. 9

Dear Mr. Markey:

The District understands that Gulf Power is working to obtain reuse water as part of Gulf Power's water conservation effort in accordance with Specific Condition No. 9 of the Individual Water Use Permit. Obtaining and utilizing reuse water to directly reduce demand for ground water and surface water would result in a significant benefit to the water resources of the area. This activity clearly meets the intent of the permit condition. If I can provide any other information or endorsement in support of this effort, please contact me.

Sincerely,

Angela Chelette, P.G.
Chief, Bureau of Ground Water Regulation

local and Tribal governments, the general public and international community to comment on the scope of the EIS, including identification of reasonable alternatives and specific issues to be addressed.

DOE will hold public scoping meetings from 5:30 p.m.–9:30 p.m. on the following dates and locations:

- July 21, 2009 Two Rivers Convention Center, 159 Main Street, Grand Junction, CO 81501.
- July 23, 2009 Embassy Suites Kansas City—Plaza, 220 West 43rd Street, Kansas City, MO 64111.
- July 28, 2009 Clarion Hotel and Conference Center, 1515 George Washington Way, Richland, WA 99352.
- July 30, 2009 North Augusta Municipal Center, 100 Georgia Avenue, North Augusta, SC 29841.
- August 4, 2009 El Capitan Resort, 540 F Street, Hawthorne, NV 89415.
- August 6, 2009 James Roberts Civic Center, 855 E. Broadway, Andrews, TX 79714.
- August 11, 2009 Shilo Inn/O'Callahans Convention Center, 780 Lindsay Blvd., Idaho Falls, ID 83402.

Additional details on the scoping meetings will be provided in local media and at *http://www.mercurystorageeis.com.*

At each scoping meeting, DOE plans to hold an open house one hour prior to the formal portion of the meetings to allow participants to register to provide oral comments, view informational materials, and engage project staff. The registration table will have an oral comment registration form as well as a sign up sheet for those who do not wish to give oral comments but who would like to be included on the mailing list to receive future information. The public may provide written and/or oral comments at the scoping meetings.

Analysis of all public comments provided during the scoping meetings as well as those submitted as described in ADDRESSES above, will be considered in helping DOE further develop the scope of the EIS and potential issues to be addressed. DOE expects to issue a Draft EIS in the fall of 2009.

Issued in Washington, DC, on June 24, 2009.

Scott Blake Harris,

General Counsel.

[FR Doc. E9–15704 Filed 7–1–09; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Basic Energy Sciences Advisory Committee

AGENCY: Department of Energy, Office of Science.

ACTION: Notice of open meeting.

SUMMARY: This notice announces a meeting of the Basic Energy Sciences Advisory Committee (BESAC). Federal Advisory Committee Act (Pub. L. 92–463, 86 Stat. 770) requires that public notice of these meetings be announced in the **Federal Register**.

DATES: Thursday, July 9, 2009, 8:30 a.m.–5:30 p.m., and Friday, July 10, 2009, 8:30 a.m. to 12 noon.

ADDRESSES: Bethesda North Marriott Hotel and Conference Center, 5701 Marinelli Road, North Bethesda, MD 20852.

FOR FURTHER INFORMATION CONTACT: Katie Perine; Office of Basic Energy Sciences; U. S. Department of Energy; Germantown Building, Independence Avenue, Washington, DC 20585; Telephone: (301) 903–6529.

SUPPLEMENTARY INFORMATION: *Purpose of the Meeting:* The purpose of this meeting is to provide advice and guidance with respect to the basic energy sciences research program.

Tentative Agenda: Agenda will include discussions of the following:

- News from Office of Science/DOE;
- News from the Office of Basic Energy Sciences;
- Report from the New Era Subcommittee's Photon Workshop;
- Energy Frontier Research Center Update;
- COV Report for Materials Science and Engineering Division;
- New BESAC Charge.

Public Participation: The meeting is open to the public. If you would like to file a written statement with the Committee, you may do so either before or after the meeting. If you would like to make oral statements regarding any of the items on the agenda, you should contact Katie Perine at 301–903–6594 (fax) or *katie.perine@science.doe.gov* (e-mail). Reasonable provision will be made to include the scheduled oral statements on the agenda. The Chairperson of the Committee will conduct the meeting to facilitate the orderly conduct of business. Public comment will follow the 10-minute rule. This notice is being published less than 15 days before the date of the meeting due to programmatic issues that had to be resolved.

Minutes: The minutes of this meeting will be available for public review and copying within 30 days at the Freedom of Information Public Reading Room; 1E–190, Forrestal Building; 1000 Independence Avenue, SW.; Washington, D.C. 20585; between 9 a.m. and 4 p.m., Monday through Friday, except holidays.

Issued in Washington, DC, on June 30, 2009.

Rachel M. Samuel,

Deputy Committee Management Officer.

[FR Doc. E9–15779 Filed 7–1–09; 8:45 am]

BILLING CODE 6450–01–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OAR–2009–0234; FRL–8925–7]

Agency Information Collection Activities: Proposed Collection; Comment Request; Information Request for National Emission Standards for Coal- and Oil-fired Electric Utility Steam Generating Units; EPA ICR No. 2362.01

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act (PRA) (44 U.S.C. 3501 *et seq.*), this action announces that EPA is planning to submit a request for a new Information Collection Request (ICR) to the Office of Management and Budget (OMB). Before submitting the ICR to OMB for review and approval, EPA is soliciting comments on the proposed information collection as described below.

DATES: Comments must be submitted on or before August 31, 2009.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2009–0234, by one of the following methods:

- *www.regulations.gov:* Follow the on-line instructions for submitting comments.
- E-mail: *a-and-r-docket@epa.gov.*
- Fax: (202) 566–1741.
- Mail: Air and Radiation Docket and Information Center, Environmental Protection Agency, Mailcode: 2282IT, 1200 Pennsylvania Ave., NW., Washington, DC 20460.
- Hand Delivery: Air and Radiation Docket and Information Center, U.S. EPA, Room 3334, EPA West Building, 1301 Constitution Avenue, NW., Washington, DC. Such deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

Instructions: Direct your comments to Docket ID No. EPA-HQ-OAR-2009-0234. EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *www.regulations.gov*, including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *www.regulations.gov* or e-mail. The *www.regulations.gov* Web site is an "anonymous access" system, which means EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an e-mail comment directly to EPA without going through *www.regulations.gov* your e-mail address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD-ROM you submit. If EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional information about EPA's public docket, visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm*.

FOR FURTHER INFORMATION CONTACT: William Maxwell, Energy Strategies Group, Sector Policies and Program Division, (D243-01), Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541-5430; fax number: (919) 541-5450; e-mail address: *maxwell.bill@epa.gov*.

SUPPLEMENTARY INFORMATION:

How Can I Access the Docket and/or Submit Comments?

EPA has established a public docket for this ICR under Docket ID No. EPA-HQ-OAR-2009-0234, which is available for online viewing at *www.regulations.gov*, or in-person viewing at the Air and Radiation Docket in the EPA Docket Center (EPA/DC), EPA West, Room 3334, 1301 Constitution Ave., NW., Washington, DC. The EPA/DC Public Reading Room is open from 8 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Reading Room is 202-566-1744, and the telephone number for the Air and Radiation Docket is 202-566-1742.

Use *www.regulations.gov* to obtain a copy of the draft collection of information, submit or view public comments, access the index listing of the contents of the docket, and to access those documents in the public docket that are available electronically. Once in the system, select "search," then key in the docket ID number identified in this document.

What Information Is EPA Particularly Interested in?

Pursuant to PRA section 3506(c)(2)(A), EPA specifically solicits comments and information to enable it to:

(i) Ealuate whether the proposed collection of information is necessary for the proper performance of the functions of the Agency, including whether the information will have practical utility;

(ii) Evaluate the accuracy of the Agency's estimate of the burden of the proposed collection of information, including the validity of the methodology and assumptions used;

(iii) enhance the quality, utility, and clarity of the information to be collected; and

(iv) minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated electronic, mechanical, or other technological collection techniques or other forms of information technology (*e.g.*, permitting electronic submission of responses).

What Should I Consider When I Prepare My Comments for EPA?

You may find the following suggestions helpful for preparing your comments.

1. Explain your views as clearly as possible and provide specific examples.
2. Describe any assumptions that you used.
3. Provide copies of any technical information and/or data you used that support your views.
4. If you estimate potential burden or costs, explain how you arrived at the estimate that you provide.
5. Offer alternative ways to improve the collection activity.
6. Make sure to submit your comments by the deadline identified under **DATES**.
7. To ensure proper receipt by EPA, be sure to identify the docket ID number assigned to this action in the subject line on the first page of your response. You may also provide the name, date, and **Federal Register** citation.

What Information Collection Activity or ICR Does This Apply to?

Affected entities: Entities potentially affected by this action are coal- and oil-fired electric utility steam generating units that emit hazardous air pollutants (HAP). Hazardous air pollutant means any pollutant listed pursuant to Clean Air Act (CAA) section 112(b). CAA section 112(a)(8) defines an electric utility steam generating unit as

* * * any fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 MWe output to any utility power distribution system for sale is also considered a utility unit.

Title: Information Collection Effort for Coal- and Oil-fired Electric Utility Steam Generating Units.

ICR numbers: EPA ICR No. 2362.01.

ICR status: This ICR is for a new information collection activity. An Agency may not conduct or sponsor, and a person is not required to respond to, a collection of information, unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in title 40 of the CFR, after appearing in the **Federal Register** when approved, are listed in 40 CFR part 9, are displayed either by publication in the **Federal Register** or by other appropriate means, such as on the related collection instrument or form, if applicable. The display of OMB control numbers in certain EPA regulations is consolidated in 40 CFR part 9.

Abstract: To obtain the information necessary to identify and categorize all coal- and oil-fired electric utility steam generating units potentially affected by the CAA section 112(d) standard, this ICR will solicit information from all potentially affected units under authority of CAA section 114. EPA intends to provide the survey in electronic format; however, written responses will also be accepted. The survey will be submitted to all facilities identified as being coal- or oil-fired electric utility steam generating units through databases available to the Agency. EPA envisions allowing recipients 3 months to respond to the survey. To further define the emission level being achieved by average of the top performing 12 percent of similar sources for the existing population, this ICR requires that certain units conduct emission testing concurrent with the survey. EPA envisions allowing recipients 6 months to respond to the emission testing requirement.

EPA estimates the cost of the information collection will be 100,370 hours and $104,807,458.

On December 20, 2000 (65 FR 79825, 79831), EPA added coal- and oil-fired electric utility steam generating units to the list of source categories under section 112(c). The CAA requires EPA to establish National Emission Standards for Hazardous Air Pollutants (NESHAP) for the control of HAP from both existing and new coal- and oil-fired electric utility steam generating units. Section 112(d) provides that for major sources, EPA must establish emission standards that reflect the maximum degree of reduction in emissions of HAP that is achievable, taking into consideration the cost of achieving the emission reduction, any non-air quality health and environmental impacts, and energy requirements. This level of control is commonly referred to as the "maximum achievable control technology" (MACT). The minimum level of emission reduction that the MACT standards must achieve is known as the "MACT floor," as defined under CAA section 112(d)(3). The MACT floor for existing sources is the emission limitation achieved by the average of the best-performing 12 percent of existing sources in the category or subcategory. For new sources, the MACT floor cannot be less stringent than the emission control achieved in practice by the best-controlled similar source. For major sources, CAA section 112(d) also requires EPA to consider whether more stringent limits—known as beyond the floor standards—are achievable after taking into consideration the cost of achieving such emission reduction, any non-air health and environmental impacts, and energy impacts.

The Agency acquired unit-specific data and data on mercury from coal-fired units in an ICR approved on November 13, 1998 (OMB Control No. 2060–0396). These data were gathered in advance of the December 20, 2000 regulatory finding. These data sources are now over 10 years old and addressed only coal-fired electric utility steam generating units and only mercury emissions from such units. The Agency is aware that significant changes have been made in the intervening years in the number of operating coal- and oil-fired units, in industry ownership practices, and in emission control configurations. Further, in light of the statutory requirements for establishing emission standards under section 112(d) and the recent case law interpreting those requirements, the Agency believes that it needs additional data from both coal- and oil-fired electric utility steam generating units. We believe that obtaining updated information will be crucial to informing our decision on the NESHAP for coal- and oil-fired electric utility steam generating units.

The information in this ICR will be collected under authority of CAA section 114. CAA section 114(a) states, in pertinent part:

For the purpose * * * (i) of * * * developing * * * any emission standard under section 7412 of this title * * * or (iii) carrying out any provision of this Chapter * * * (1) the Administrator may require any person who owns or operates any emission source * * * who the Administrator believes may have information necessary for the purposes set forth in this subsection * * * on a one-time, periodic or continuous basis to- * * * (B) make such reports * * *; (E) keep records on control equipment parameters, production variables or other indirect data when direct monitoring of emissions is impractical * * *, and (G) provide such other information as the Administrator may reasonably require * * *

The data collected will be used to confirm the population of potentially affected coal- and oil-fired electric utility steam generating units, and update existing emission test data and fuel analysis information. These data will be used by the Agency to develop the NESHAP for coal- and oil-fired electric utility steam generating units under CAA section 112(d). Specifically, the data will provide the Agency with updated information on the number of potentially affected units, and available emission test data and fuel analysis data to address variability. All data collected will be added to existing emission test databases for coal- and oil-fired electric utility steam generating units; it will also be used to further evaluate the HAP emissions from these sources.

This collection of information is mandatory under CAA section 114 (42 U.S.C. 7414). All information submitted to EPA pursuant to this ICR for which a claim of confidentiality is made is safeguarded according to Agency policies in 40 CFR part 2, subpart B. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. OMB control numbers for EPA's regulations in 40 CFR are listed in 40 CFR part 9.

The EPA would like to solicit comments to:

(i) Evaluate whether the proposed collection of information is necessary for the proper performance of the functions of the Agency, including whether the information will have practical utility;

(ii) Evaluate the accuracy of the Agency's estimate of the burden of the proposed collection of information, including the methodology and assumptions used;

(iii) Enhance the quality, utility, and clarity of the information to be collected; and

(iv) Minimize the burden of the collection of information on those who are to respond, including through the use of appropriate automated electronic, mechanical, or other technological collection techniques or other forms of information technology (*e.g.*, permitting electronic submission of responses).

Burden Statement: The projected cost and hour burden for this one-time collection of information is $104,807,458 and 100,370 hours. This burden is based on an estimated 555 facilities (1,325 units) being respondents to the survey and required emission testing. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements which have subsequently changed; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

The ICR provides a detailed explanation of the Agency's estimate, which is only briefly summarized here.

Estimated total number of potential respondents: 555 facilities (1,325 units).

Frequency of response: One time.

Estimated total average number of responses for each respondent: 1.

Estimated total annual burden hours: 100,370.

Estimated total annual burden costs: $104,807,458.

What Is the Next Step in the Process for This ICR?

EPA will consider the comments received and amend the ICR as appropriate. The final ICR package will then be submitted to OMB for review and approval pursuant to 5 CFR 1320.12. At that time, EPA will issue another **Federal Register** notice pursuant to 5 CFR 1320.5(a)(1)(iv) to announce the submission of the ICR to OMB and the opportunity to submit additional comments to OMB. If you have any questions about this ICR or the approval process, please contact the technical person listed under **FOR FURTHER INFORMATION CONTACT.**

Dated: June 26, 2009.

Mary E. Henigin,

Acting Director, Sector Policies and Programs Division.

[FR Doc. E9-15686 Filed 7-1-09; 8:45 am]

BILLING CODE 6560-50-P

ENVIRONMENTAL PROTECTION AGENCY

[EPA-HQ-OECA-2008-0369; FRL-8925-4]

Agency Information Collection Activities; Submission to OMB for Review and Approval; Comment Request; NESHAP for Clay Ceramics Manufacturing (Renewal), EPA ICR Number 2023.04, OMB Control Number 2060-0513

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: In compliance with the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*), this document announces that an Information Collection Request (ICR) has been forwarded to the Office of Management and Budget (OMB) for review and approval. This is a request to renew an existing approved collection. The ICR, which is abstracted below, describes the nature of the collection and the estimated burden and cost.

DATES: Additional comments may be submitted on or before August 3, 2009.

ADDRESSES: Submit your comments, referencing docket ID number EPA-OECA-2008-0369, to (1) EPA online using *http://www.regulations.gov* (our preferred method), or by e-mail to *docket.oeca@epa.gov*, or by mail to: EPA Docket Center (EPA/DC), Environmental Protection Agency, Enforcement and Compliance Docket and Information Center, mail code 28221T, 1200 Pennsylvania Avenue, NW., Washington, DC 20460, and (2) OMB at: Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), Attention: Desk Officer for EPA, 725 17th Street, NW., Washington, DC 20503.

FOR FURTHER INFORMATION CONTACT: Sounjay Gairola, Office of Enforcement and Compliance Assurance, Mail Code 2242A, Environmental Protection Agency, 1200 Pennsylvania Avenue, NW., Washington, DC 20460; telephone number: (202) 564-4003; e-mail address: *gairola.sounjay@epa.gov.*

SUPPLEMENTARY INFORMATION: EPA has submitted the following ICR to OMB for review and approval according to the procedures prescribed in 5 CFR 1320.12. On May 30, 2008 (73 FR 31088), EPA sought comments on this ICR pursuant to 5 CFR 1320.8(d). EPA received no comments. Any additional comments on this ICR should be submitted to EPA and OMB within 30 days of this notice.

EPA has established a public docket for this ICR under docket ID number EPA-HQ-OECA-2008-0369, which is available for public viewing online at *http://www.regulations.gov*, in person viewing at the Enforcement and Compliance Docket in the EPA Docket Center (EPA/DC), EPA West, Room 3334, 1301 Constitution Avenue, NW., Washington, DC. The EPA Docket Center Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Reading Room is (202) 566-1744, and the telephone number for the Enforcement and Compliance Docket is (202) 566-1752.

Use EPA's electronic docket and comment system at *http://www.regulations.gov*, to submit or view public comments, access the index listing of the contents of the docket, and to access those documents in the docket that are available electronically. Once in the system, select "docket search," then key in the docket ID number identified above. Please note that EPA's policy is that public comments, whether submitted electronically or in paper, will be made available for public viewing at *http://www.regulations.gov*, as EPA receives them and without change, unless the comment contains copyrighted material, Confidential Business Information (CBI), or other information whose public disclosure is restricted by statute. For further information about the electronic docket, go to *http://www.regulations.gov*.

Title: NESHAP for Clay Ceramics Manufacturing (Renewal).

ICR Numbers: EPA ICR Number 2023.04, OMB Control Number 2060-0513.

ICR Status: This ICR is scheduled to expire on August 31, 2009. Under OMB regulations, the Agency may continue to conduct or sponsor the collection of information while this submission is pending at OMB. An Agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for EPA's regulations in title 40 of the CFR, after appearing in the **Federal Register** when approved, are listed in 40 CFR part 9, and displayed either by publication in the **Federal Register** or by other appropriate means, such as on the related collection instrument or form, if applicable. The display of OMB control numbers in certain EPA regulations is consolidated in 40 CFR part 9.

Abstract: The National Emission Standards for Hazardous Air Pollutants (NESHAP) for Clay Ceramics Manufacturing (40 CFR part 63, subpart KKKKK) were proposed on July 22, 2002 (67 FR 47893) and promulgated on May 16, 2003 (67 FR 26738).

The affected entities are subject to the General Provisions of the NESHAP at 40 CFR part 63, subpart A, and any changes, or additions to the General Provisions specified at 40 CFR part 63, subpart KKKKK.

Owners or operators of the affected facilities must submit a one-time-only report of any physical or operational changes, initial performance tests, and periodic reports and results. Owners or operators are also required to maintain records of the occurrence and duration of any startup, shutdown, or malfunction in the operation of an affected facility, or any period during which the monitoring system is inoperative. Reports, at a minimum, are required semiannually.

Burden Statement: The annual public reporting and recordkeeping burden for this collection of information is estimated to average 17 hours per response. Burden means the total time, effort, or financial resources expended by persons to generate, maintain, retain, or disclose or provide information to or for a Federal agency. This includes the time needed to review instructions; develop, acquire, install, and utilize technology and systems for the purposes of collecting, validating, and verifying information, processing and maintaining information, and disclosing and providing information; adjust the existing ways to comply with any previously applicable instructions and requirements which have subsequently changed; train personnel to be able to respond to a collection of information; search data sources; complete and review the collection of information; and transmit or otherwise disclose the information.

Respondents/Affected Entities: Clay ceramics manufacturing facilities.

Estimated Number of Respondents: 10.

Frequency of Response: Initially, occasionally, and semiannually.

Estimated Total Annual Hour Burden: 527.

Estimated Total Annual Cost: $45,702, which includes labor costs of $42,532, O&M costs of $2,468, and annualized capital/startup costs of $702.

Changes in the Estimates: There is no change in the total estimated burden

Schedule 1A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2008 - December 2008

Line		Period Amount ($)
1	End of Period Actual Total True-Up for the Period January 2008 - December 2008 (Schedule 2A, Line 5 + 6)	(1,428,879)
2	Estimated/Actual True-Up Amount approved for the period January 2008 - December 2008 (FPSC Order No. PSC-08-0775-FOF-EI)	(2,810,290)
3	Final True-Up Amount to be refunded/(recovered) in the in the projection period January 2010 - December 2010 (Lines 1 - 2)	1,381,411

Docket No. 090007-EI
ECRC 2009 Final True-up
Exhibit RWD-1, Page 1 of 38

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 32
COMPANY Gulf Power Company (Direct)
WITNESS R. W. Dodd (RWD-1)
DATE 11/02/09

Schedule 2A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2008 - December 2008

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)	4,058.103	3,422,308	3,346.536	3,480.637	4,329.372	4,831,384	5,305,640	4,867,102	4,656.354	3,769.208	3,472,081	4,439,433	49,978.158
2	True-Up Provision (Order No PSC-07-0922-FOF-EI)	11,705	11,705	11,705	11,705	11,705	11,705	11,705	11,705	11,705	11,705	11,705	11,704	140,459
3	**ECRC Revenues Applicable to Period (Lines 1 + 2)**	4,069.808	3,434.013	3,358,241	3,492,342	4.341,077	4,843,089	5,317,345	4.878,807	4.668.059	3.780,913	3.483,786	4.451,137	50,118,617
4	Jurisdictional ECRC Costs													
	a O & M Activities (Schedule 5A, Line 9)	1,193,539	1,711,847	905,878	1,280,921	930,661	1,519,145	1,317,052	1,012,236	1,397.131	814,418	857,324	1,089,175	14,029,327
	b Capital Investment Projects (Schedule 7A, Line 9)	2,878,246	2.907,557	2,946,619	3,072,904	3,180.615	3,206,613	3,221,888	3,217,077	3,223,763	3,218,907	3,214,160	3,238,909	37,527.258
	c **Total Jurisdictional ECRC Costs**	4,071,785	4,619,404	3.852,497	4.353,825	4,111,276	4,725,758	4,538,940	4,229.313	4,620,894	4.033,325	4,071.484	4.328,084	51,556.585
5	**Over/(Under) Recovery (Line 3 - Line 4c)**	(1,977)	(1,185,391)	(494,256)	(861,483)	229,801	117.331	778,405	649,494	47,165	(252,412)	(587,698)	123,053	(1,437,968)
6	Interest Provision (Schedule 3A, Line 10)	5,387	2,577	369	(1,217)	(1,895)	(1,429)	(546)	884	2,377	2,170	425	(12)	9.089
7	Beginning Balance True-Up & Interest Provision													
	a Actual Total for True-Up Period 2007	(647,455)	(655,750)	(1,850,269)	(2,355.861)	(3,230,266)	(3,014,065)	(2,909,868)	(2,143,714)	(1,505,042)	(1,467,204)	(1,729,152)	(2,328.130)	(647.455)
	b Final True-Up from January 2006 - December 2006 (Order No PSC-07-0922-FOF-EI)	2,258,385	2,258,385	2,258.385	2,258,385	2,258.385	2,258.385	2,258,385	2,258,385	2,258,385	2,258,385	2,258.385	2,258,385	2.258.385
8	True-Up Collected/(Refunded) (see Line 2)	(11,705)	(11,705)	(11,705)	(11,705)	(11,705)	(11,705)	(11,705)	(11,705)	(11,705)	(11,705)	(11,705)	(11,704)	(140,459)
9	Adjustments													
10	End of Period Total True-Up (Lines 5 + 6 + 7a + 7b + 8)	1,602,635	408,116	(97,476)	(971,881)	(755,680)	(651,483)	114,671	753,343	791,181	529,233	(69,745)	41,592	41,592

Docket No. 090007-EI
ECRC 2009 Final True-up
Exhibit RWD-1, Page 2 of 38

Schedule 3A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2008 - December 2008

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)	1,610,930	1,602,635	408,116	(97,476)	(971,881)	(755,680)	(651,483)	114,671	753,343	791,181	529,233	(69,745)	
2	Ending True-Up Amount Before Interest (Line 1 + Schedule 2A, Lines 5 + 8)	1,597,248	405,539	(97,845)	(970,664)	(753,785)	(650,054)	115,217	752,460	788,803	527,064	(70,170)	41,604	
3	*Total of Beginning & Ending True-up (Lines 1 + 2)*	3,208,178	2,008,173	310,271	(1,068,140)	(1,725,666)	(1,405,734)	(536,266)	867,131	1,542,147	1,318,244	459,064	(28,141)	
4	Average True-Up Amount (Line 3 x 1/2)	1,604,089	1,004,087	155,136	(534,070)	(862,833)	(702,867)	(268,133)	433,565	771,073	659,122	229,532	(14,070)	
5	Interest Rate (First Day of Reporting Business Month)	0.049800	0.030800	0.030800	0.026300	0.028400	0.024300	0.024500	0.024400	0.024500	0.049500	0.029500	0.014900	
6	Interest Rate (First Day of Subsequent Business Month)	0.030800	0.030800	0.026300	0.028400	0.024300	0.024500	0.024400	0.024500	0.049500	0.029500	0.014900	0.005400	
7	Total of Beginning and Ending Interest Rates (Line 5 + Line 6)	0.080600	0.061600	0.057100	0.054700	0.052700	0.048800	0.048900	0.048900	0.074000	0.079000	0.044400	0.020300	
8	*Average Interest Rate (Line 7 x 1/2)*	*0.040300*	*0.030800*	*0.028550*	*0.027350*	*0.026350*	*0.024400*	*0.024450*	*0.024450*	*0.037000*	*0.039500*	*0.022200*	*0.010150*	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.003358	0.002567	0.002379	0.002279	0.002196	0.002033	0.002038	0.002038	0.003083	0.003292	0.001850	0.000846	
10	Interest Provision for the Month (Line 4 x Line 9)	5,387	2,577	369	(1,217)	(1,895)	(1,429)	(546)	884	2,377	2,170	425	(12)	9,089

Docket No. 090007-EI
ECRC 2009 Final True-up
Exhibit RWD-1, Page 3 of 38

Schedule 4A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2008 - December 2008

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	824,122	824,622	(500)	(0.1)	%
	.3 Title V	102,830	98,173	4,657	4.7	%
	.4 Asbestos Fees	300	2,184	(1,884)	(86.3)	%
	.5 Emission Monitoring	509,981	530,117	(20,136)	(3.8)	%
	.6 General Water Quality	408,499	366,108	42,391	11.6	%
	.7 Groundwater Contamination Investigation	1,494,099	1,504,437	(10,338)	(0.7)	%
	.8 State NPDES Administration	42,000	42,000	0	0.0	%
	9 Lead and Copper Rule	20,890	21,348	(458)	(2.1)	%
	.10 Env Auditing/Assessment	18,847	6,700	12,147	181.3	%
	.11 General Solid & Hazardous Waste	428,048	373,491	54,557	14.6	%
	.12 Above Ground Storage Tanks	106,811	177,549	(70,738)	(39.8)	%
	.13 Low Nox	0	0	0	0.0	%
	.14 Ash Pond Diversion Curtains	0	0	0	0.0	%
	.15 Mercury Emissions	0	0	0	0.0	%
	.16 Sodium Injection	207,299	247,939	(40,640)	(16.4)	%
	.17 Gulf Coast Ozone Study	0	0	0	0.0	%
	.18 SPCC Substation Project	68,945	0	68,945	0.0	%
	.19 FDEP NOX Reduction Agreement	3,639,883	3,713,809	(73,926)	(2.0)	%
	.20 CAIR/CAMR/CAVR Compliance Program	583,406	473,267	110,139	23.3	%
	.21 Mercury Allowances	0	0	0	0.0	%
	22 Annual NOx Allowances	0	0	0	0.0	%
	.23 Seasonal NOx Allowances	0	0	0	0.0	%
	.24 SO2 Allowances	6,047,510	6,835,142	(787,632)	(11.5)	%
2	Total O & M Activities	14,503,470	15,216,886	(713,416)	(4.7)	%
3	Recoverable Costs Allocated to Energy	11,915,031	12,723,069	(808,038)	(6.4)	%
4	Recoverable Costs Allocated to Demand	2,588,439	2,493,817	94,622	3.8	%

Notes:

Column (1) is the End of Period Totals on Schedule 5A
Column (2) contains the approved Estimated/Actual amounts in accordance with FPSC Order No. PSC-08-0775-FOF-EI
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2008 - December 2008

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	Energy
1	Description of O & M Activities															
	1 Sulfur	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.2 Air Emission Fees	-	700,225	23	-	-	-	-	-	-	-	-	123,874	824,122	0	824,122
	3 Title V	8,180	9,382	8,735	7,963	6,200	8,317	9,668	8,906	9,299	8,686	8,365	9,129	102,830	0	102,830
	.4 Asbestos Fees	1,500	-	300	(1,537)	(79)	-	-	-	-	300	-	(184)	300	300	0
	5 Emission Monitoring	30,700	31,550	59,328	39,967	43,127	40,897	23,046	47,554	36,120	40,971	43,706	73,015	509,981	0	509,981
	6 General Water Quality	9,714	25,580	12,045	15,198	28,455	47,583	40,869	39,012	77,796	46,332	42,477	23,438	408,499	408,499	0
	7 Groundwater Contamination Investigation	(6,161)	64,126	84,006	62,604	122,829	561,836	179,514	33,258	253,815	59,367	41,162	37,743	1,494,099	1,494,099	0
	.8 State NPDES Administration	-	-	-	-	-	-	-	-	-	-	7,500	34,500	42,000	42,000	0
	9 Lead and Copper Rule	3,583	-	3,036	-	547	3,382	-	3,974	300	6,068	-	-	20,890	20,890	0
	.10 Env Auditing/Assessment	-	-	3,909	377	414	-	10,302	2,808	21	-	215	801	18,847	18,847	0
	11 General Solid & Hazardous Waste	19,751	15,681	55,590	30,230	36,632	35,756	71,588	33,756	16,933	38,192	17,134	56,805	428,048	428,048	0
	12 Above Ground Storage Tanks	(7,688)	7,188	35,683	24,143	(7,078)	5,491	25,468	341	1,127	-	19,697	2,439	106,811	106,811	0
	.13 Low Nox	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	14 Ash Pond Diversion Curtains	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	15 Mercury Emissions	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	16 Sodium Injection	18,013	18,068	5,376	24,848	17,380	29,554	7,314	14,571	22,607	7,844	7,457	34,267	207,299	0	207,299
	17 Gulf Coast Ozone Study	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	18 SPCC Substation Project	-	-	-	-	-	-	-	-	-	-	14,155	54,790	68,945	0	68,945
	.19 FDEP NOX Reduction Agreement	596,519	389,227	169,915	438,599	207,430	258,005	303,745	215,627	281,206	250,847	305,751	223,012	3,639,883	0	3,639,883
	20 CAIR/CAMR/CAVR Compliance Program	-	-	-	169,999	55,534	(10,665)	19,182	20,261	197,080	21,529	19,557	90,929	583,406	0	583,406
	21 Mercury Allowances	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	22 Annual NOx Allowances	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.23 Seasonal NOx Allowances	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	24 SO2 Allowances	563,792	510,454	499,179	509,587	449,566	590,490	668,732	624,613	545,756	361,070	359,941	364,330	6,047,510	0	6,047,510
2	Total of O & M Activities	1,237,903	1,771,481	937,125	1,321,978	960,957	1,570,646	1,359,428	1,044,681	1,442,060	841,206	887,117	1,128,888	14,503,470	2,519,494	11,983,976
3	Recoverable Costs Allocated to Energy	1,217,204	1,658,906	742,556	1,190,963	779,237	916,598	1,031,687	931,532	1,092,068	690,947	744,777	918,556	11,915,031		
4	Recoverable Costs Allocated to Demand	20,699	112,575	194,569	131,015	181,720	654,048	327,741	113,149	349,992	150,259	142,340	210,332	2,588,439		
5	Retail Energy Jurisdictional Factor	0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849			
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)	1,173,581	1,603,301	718,271	1,154,594	755,444	888,501	1,001,039	903,136	1,059,663	669,536	720,077	886,370	11,533,513		
8	Jurisdictional Demand Recoverable Costs (B)	19,958	108,546	187,607	126,327	175,217	630,644	316,013	109,100	337,468	144,882	137,247	202,805	2,495,814		
9	Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8)	1,193,539	1,711,847	905,878	1,280,921	930,661	1,519,145	1,317,052	1,012,236	1,397,131	814,418	857,324	1,089,175	14,029,327		

Notes:
(A) Line 3 x Line 5 x 1.0007 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 2008 - December 2008

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	46,339	46,344	(5)	(0.0)	%
.2	Crist 5, 6 & 7 Precipitator Projects	1,942,918	1,951,133	(8,215)	(0.4)	%
.3	Crist 7 Flue Gas Conditioning	168,690	168,693	(3)	(0.0)	%
.4	Low NOx Burners, Crist 6 & 7	2,052,286	2,052,284	2	0.0	%
.5	CEMS - Plants Crist, Scholz, Smith, & Daniel	820,797	832,135	(11,338)	(1.4)	%
.6	Sub Contam. Mobile Groundwater Treat Sys	104,419	104,412	7	0.0	%
.7	Raw Water Well Flowmeters - Plants Crist & Smith	27,821	27,825	(4)	(0.0)	%
.8	Crist Cooling Tower Cell	59,390	59,391	(1)	(0.0)	%
.9	Crist 1-5 Dechlorination	28,377	28,374	3	0.0	%
.10	Crist Diesel Fuel Oil Remediation	7,119	7,121	(2)	(0.0)	%
.11	Crist Bulk Tanker Unload Sec Contain Struc	9,442	9,446	(4)	(0.0)	%
.12	Crist IWW Sampling System	5,502	5,502	0	0.0	%
.13	Sodium Injection System	49,924	49,923	1	0.0	%
.14	Smith Stormwater Collection System	259,100	259,098	2	0.0	%
.15	Smith Waste Water Treatment Facility	36,307	36,309	(2)	(0.0)	%
.16	Daniel Ash Management Project	2,113,885	2,113,083	802	0.0	%
.17	Smith Water Conservation	16,627	16,633	(6)	(0.0)	%
.18	Underground Fuel Tank Replacement	0	0	0	0.0	%
.19	Crist FDEP Agreement for Ozone Attainment	18,239,305	18,263,765	(24,460)	(0.1)	%
.20	Crist Stormwater Collection System	128,439	128,437	2	0.0	%
.21	Crist Common FTIR Monitor	8,122	8,126	(4)	(0.0)	%
.22	Precipitator Upgrades for CAM Compliance	3,839,369	3,835,676	3,693	0.1	%
.23	Plant Groundwater Investigation	0	0	0	0.0	%
.24	Crist Water Conservation	13,435	13,086	349	2.7	%
.25	Crist Condenser Tubes	811,688	808,517	3,171	0.4	%
.26	CAIR/CAMR/CAVR Compliance	6,859,590	7,056,845	(197,255)	(2.8)	%
.27	General Water Quality	7,140	7,137	3	0.0	%
.28	Mercury Allowances	0	0	0	0.0	%
.29	Annual Nox Allowances	0	0	0	0.0	%
.30	Seasonal Nox Allowances	0	0	0	0.0	%
.31	SO2 Allowances	1,119,632	1,101,320	18,312	1.7	%
2	Total Investment Projects - Recoverable Costs	38,775,663	38,990,615	(214,952)	(0.6)	%
3	Recoverable Costs Allocated to Energy	35,426,104	35,651,631	(225,527)	(0.6)	%
4	Recoverable Costs Allocated to Demand	3,349,559	3,338,984	10,575	0.3	%

Notes:
Column (1) is the End of Period Totals on Schedule 7A
Column (2) contains the approved Estimated/Actual amounts in accordance with FPSC Order No PSC-08-0775-FOF-EI
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2008 - December 2008

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	3,998	3,973	3,948	3,923	3,899	3,874	3,849	3,824	3,800	3,775	3,750	3,726	46,339	0	46,339
	2 Crist 5, 6 & 7 Precipitator Projects	164,510	164,039	163,565	163,093	162,619	162,148	161,672	161,201	160,726	160,255	159,781	159,309	1 942,918	0	1,942,918
	3 Crist 7 Flue Gas Conditioning	14,068	14,067	14,064	14,062	14,060	14,059	14,057	14,054	14,053	14,051	14,049	14,046	168,690	0	168,690
	4 Low NOx Burners, Crist 6 & 7	172,282	172,054	171 824	171,596	171,367	171,138	170,910	170,680	170,451	170,223	169,994	169,767	2,052,286	0	2,052,286
	5 CEMS - Plants Crist, Scholz, Smith & Daniel	64,247	64,141	64 032	65,227	66,422	71,502	73,484	70,207	70,057	70,057	70,190	71,231	820,797	0	820,797
	.6 Sub Contam Mobile Groundwater Treat Sys	8,795	8,779	8,762	8,745	8,727	8 712	8 693	8,676	8,659	8,642	8,623	8,606	104,419	96,387	8,032
	7 Raw Water Well Flowmeters - Plants Crist & Smith	2,349	2,343	2,339	2,333	2,327	2,322	2,316	2,310	2,303	2,300	2,293	2,286	27,821	25,680	2,141
	8 Crist Cooling Tower Cell	4,970	4,950	4,956	4,953	4,950	4,949	4,948	4,946	4,944	4,943	4,941	4,940	59,390	54,822	4,568
	9 Crist 1-5 Dechlorination	2,406	2,399	2,392	2,383	2,376	2,369	2,360	2,353	2,347	2,338	2,330	2,324	28,377	26,193	2,184
	10 Crist Diesel Fuel Oil Remediation	603	601	600	598	596	595	592	591	589	586	586	582	7,119	6,572	547
	11 Crist Bulk Tanker Unload Sec Contain Struc	801	799	795	794	791	787	786	783	780	778	776	772	9,442	8,716	726
	12 Crist IWW Sampling System	467	466	464	462	461	459	458	457	455	452	452	449	5,502	5,078	424
	13 Sodium Injection System	4,212	4,202	4,192	4,184	4,174	4,166	4,155	4,148	4,137	4,126	4,119	4,109	49,924	0	49,924
	14 Smith Stormwater Collection System	21,892	21,838	21,783	21,729	21,673	21,618	21,564	21,509	21,455	21,401	21,346	21,292	259,100	239,169	19,931
	15 Smith Waste Water Treatment Facility	3,045	3,042	3,037	3,033	3,031	3,026	3 024	3,020	3 017	3,014	3,011	3,007	36,307	33,517	2,790
	16 Daniel Ash Management Project	178,747	178,270	177,792	177,305	176,813	176,325	175,887	175,443	174,985	174,562	174,112	173,644	2,113,885	1,951,277	162,608
	17 Smith Water Conservation	1,400	1,397	1,395	1 392	1,390	1,387	1,386	1,380	1,379	1,376	1,374	1,371	16,627	15,348	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	1,534,268	1,533,932	1,533,514	1,529,852	1,526,182	1,522,534	1,518 877	1,515,200	1,511,546	1,507,877	1,503,984	1,501,539	18,239,305	0	18,239,305
	20 Crist Stormwater Collection System	10,830	10,807	10,784	10,762	10,738	10,715	10,691	10,669	10,645	10,622	10,600	10,576	128,439	118,559	9,880
	21 Crist Common FTIR Monitor	686	684	682	682	679	677	676	675	672	671	670	668	8 122	0	8,122
	22 Precipitator Upgrades for CAM Compliance	232,460	258,161	298,220	330,809	338,911	340,676	340,689	340,622	340,622	340,139	339,345	338,715	3,839,369	0	3,839,369
	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	1,426	13,435	12,401	1,034
	25 Crist Condenser Tubes	67,521	67,373	67,228	67,079	66,934	66,853	69,278	69,585	67,441	67,385	67,461	67,550	811,688	749,249	62,439
	26 CAIR/CAMR/CAVR Compliance	365,808	370,958	375,761	475,969	589,483	621,643	640,934	652,723	669,856	678,750	689,889	727,816	6,859,590	0	6,859,590
	27 General Water Quality	615	611	608	605	601	597	593	590	585	582	578	575	7 140	6,591	549
	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	123,134	118,067	113,304	108,546	102,006	95,266	89,317	83,025	77,505	73,227	69,826	66,409	1,119,632	0	1,119,632
2	Total Investment Projects - Recoverable Costs	2,985,218	3,009,054	3,047,140	3,171,212	3,282,304	3,309,488	3,322,286	3,319,758	3,324,094	3,323,214	3,325,160	3,356,735	38,775,663	3,349,559	35,426,104
3	Recoverable Costs Allocated to Energy	2,703,176	2,727,724	2,766 495	2,891,270	3,003,071	3,030,897	3,041,981	3,039,698	3,046,553	3,046,233	3,048,638	3,080,368	35,426,104		
4	Recoverable Costs Allocated to Demand	282,042	281,330	280,645	279,942	279,233	278,591	280,305	280,060	277,541	276,981	276,522	276,367	3,349,559		
5	Retail Energy Jurisdictional Factor	0 9634865	0 9658052	0 9666186	0 9687846	0 9687876	0 9686688	0 9696144	0 9688390	0 9696486	0 9683344	0 9661598	0 9642849			
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)	2,606,297	2,636,294	2,676,017	2,802,979	2,911,374	2,937,991	2,951,613	2,947,039	2,956,154	2,951,837	2,947,533	2,972,432	34,297 560		
8	Jurisdictional Demand Recoverable Costs (C)	271,949	271,263	270,602	269,925	269,241	268,622	270,275	270,038	267,609	267,070	266,627	266,477	3,229,698		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	2,878,246	2,907,557	2,946,619	3,072,904	3,180,615	3,206,613	3,221,888	3,217,077	3,223,763	3,218,907	3,214,160	3,238,909	37,527,258		

Notes:

(A) Pages 1-27 of Schedule 8A Line 9 Pages 28-31 of Schedule 8A, 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 Final True-Up 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	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	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)	(73,211)	(75,834)	(78,456)	(81,079)	(83,701)	(86,324)	(88,946)	(91,569)	(94,191)	(96,814)	(99,436)	(102,059)	(104,682)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	147,083	144,460	141,838	139,215	136,593	133,970	131,348	128,725	126,103	123,480	120,858	118,235	115,612	
6	Average Net Investment		145,772	143,149	140,527	137,904	135,282	132,659	130,037	127,414	124,792	122,169	119,547	116,924	
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	2,622	2,623	2,622	2,623	2,622	2,623	2,622	2,623	2,622	2,623	2,623	31,471
	c Dismantlement		0	0	0	0	0	0	0	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	3,973	3,948	3,923	3,899	3,874	3,849	3,824	3,800	3,775	3,750	3,726	46,339
	a Recoverable Costs Allocated to Energy		3,998	3,973	3,948	3,923	3,899	3,874	3,849	3,824	3,800	3,775	3,750	3,726	46,339
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
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	3,840	3,819	3,803	3,780	3,755	3,735	3,707	3,687	3,658	3,626	3,595	44,860
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)		3,855	3,840	3,819	3,803	3,780	3,755	3,735	3,707	3,687	3,658	3,626	3,595	44,860

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 amortization; 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 Final True-Up 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	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	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)	(2,382,642)	(2,432,772)	(2,482,904)	(2,533,034)	(2,583,166)	(2,633,297)	(2,683,429)	(2,733,560)	(2,783,692)	(2,833,823)	(2,883,955)	(2,934,087)	(2,984,219)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	12,149,236	12,099,106	12,048,974	11,998,844	11,948,712	11,898,581	11,848,449	11,798,318	11,748,186	11,698,055	11,647,923	11,597,791	11,547,659	
6	Average Net Investment		12,124,171	12,074,040	12,023,909	11,973,778	11,923,647	11,873,515	11,823,384	11,773,252	11,723,121	11,672,989	11,622,857	11,572,725	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		89,077	88,708	88,340	87,972	87,603	87,235	86,866	86,499	86,130	85,761	85,393	85,025	1,044,609
	b Debt Component (Line 6 x Debt Component x 1/12)		25,303	25,199	25,095	24,989	24,885	24,781	24,675	24,570	24,465	24,362	24,256	24,152	296,732
8	Investment Expenses														
	a Depreciation (E)		38,756	38,756	38,756	38,756	38,757	38,756	38,757	38,756	38,757	38,756	38,758	38,758	465,079
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		11,374	11,376	11,374	11,376	11,374	11,376	11,374	11,376	11,374	11,376	11,374	11,374	136,498
	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)		164,510	164,039	163,565	163,093	162,619	162,148	161,672	161,201	160,726	160,255	159,781	159,309	1,942,918
	a Recoverable Costs Allocated to Energy		164,510	164,039	163,565	163,093	162,619	162,148	161,672	161,201	160,726	160,255	159,781	159,309	1,942,918
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
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)		158,614	158,541	158,216	158,114	157,654	157,178	156,869	156,287	155,957	155,289	154,482	153,727	1,880,928
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)		158,614	158,541	158,216	158,114	157,654	157,178	156,869	156,287	155,957	155,289	154,482	153,727	1,880,928

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) 3.2% 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 Final True-Up 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	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	1,469,714	1,469,510	1,469,306	1,469,102	1,468,899	1,468,695	1,468,491	1,468,287	1,468,084	1,467,880	1,467,676	1,467,472	1,467,269	
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)	1,469,714	1,469,510	1,469,306	1,469,102	1,468,899	1,468,695	1,468,491	1,468,287	1,468,084	1,467,880	1,467,676	1,467,472	1,467,269	
6	Average Net Investment		1,469,612	1,469,408	1,469,204	1,469,001	1,468,797	1,468,593	1,468,389	1,468,186	1,467,982	1,467,778	1,467,574	1,467,371	
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	203	204	204	204	203	204	204	204	203	2,445
	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	14,062	14,060	14,059	14,057	14,054	14,053	14,051	14,049	14,046	168,690
	a Recoverable Costs Allocated to Energy		14,068	14,067	14,064	14,062	14,060	14,059	14,057	14,054	14,053	14,051	14,049	14,046	168,690
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
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)		13,564	13,595	13,604	13,633	13,631	13,628	13,639	13,626	13,636	13,616	13,583	13,554	163,309
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)		13,564	13,595	13,604	13,633	13,631	13,628	13,639	13,626	13,636	13,616	13,583	13,554	163,309

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 Final True-Up 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	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	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)	6,604,116	6,579,852	6,555,588	6,531,324	6,507,060	6,482,796	6,458,532	6,434,268	6,410,004	6,385,740	6,361,476	6,337,211	6,312,945	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	15,702,039	15,677,775	15,653,511	15,629,247	15,604,983	15,580,719	15,556,455	15,532,191	15,507,927	15,483,663	15,459,399	15,435,134	15,410,868	
6	Average Net Investment		15,689,907	15,665,643	15,641,379	15,617,115	15,592,851	15,568,587	15,544,323	15,520,059	15,495,795	15,471,531	15,447,267	15,423,001	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		115,274	115,095	114,917	114,739	114,561	114,382	114,204	114,026	113,847	113,670	113,490	113,313	1,371,518
	b Debt Component (Line 6 x Debt Component x 1/12)		32,744	32,695	32,643	32,593	32,542	32,492	32,442	32,390	32,340	32,289	32,239	32,188	389,597
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	24,265	24,266	291,171
	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)		172,282	172,054	171,824	171,596	171,367	171,138	170,910	170,680	170,451	170,223	169,994	169,767	2,052,286
	a Recoverable Costs Allocated to Energy		172,282	172,054	171,824	171,596	171,367	171,138	170,910	170,680	170,451	170,223	169,994	169,767	2,052,286
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
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)		166,108	166,287	166,205	166,356	166,134	165,892	165,833	165,477	165,393	164,948	164,356	163,818	1,986,807
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		166,108	166,287	166,205	166,356	166,134	165,892	165,833	165,477	165,393	164,948	164,356	163,818	1,986,807

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 Final True-Up Amount
January 2008 - December 2008

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, 1357, 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	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	277,167	443	1,098,159	(745,439)	28,912	9,022	14,100	39,569	67,919	
	b Clearings to Plant		0	0	0	0	0	0	252,857	29,239	4,099	(1,728)	0	692,586	
	c Retirements		0	0	0	0	0	0	0	157,729	0	0	0	70,000	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	764	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	4,298,478	4,298,478	4,298,478	4,298,478	4,298,478	4,298,478	4,298,478	4,551,335	4,422,845	4,426,944	4,425,216	4,425,216	5,047,802	
3	Less: Accumulated Depreciation (C)	949,689	937,922	926,149	914,377	902,604	890,837	879,060	866,849	1,012,146	999,932	987,712	975,495	1,033,395	
4	CWIP - Non Interest Bearing	187,201	187,201	187,201	187,201	464,368	464,811	1,562,970	564,674	564,347	569,270	585,098	624,667	0	
5	Net Investment (Lines 2 + 3 + 4)	5,435,368	5,423,601	5,411,828	5,400,056	5,665,450	5,654,126	6,740,508	5,982,858	5,999,338	5,996,146	5,998,026	6,025,378	6,081,197	
6	Average Net Investment		5,429,484	5,417,714	5,405,942	5,532,753	5,659,788	6,197,317	6,361,683	5,991,098	5,997,742	5,997,086	6,011,702	6,053,287	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		39,892	39,802	39,718	40,647	41,585	45,531	46,740	44,015	44,066	44,061	44,168	44,474	514,699
	b Debt Component (Line 6 x Debt Component x 1/12)		11,329	11,307	11,283	11,548	11,811	12,935	13,274	12,501	12,518	12,517	12,546	12,634	146,203
8	Investment Expenses														
	a Depreciation (E)		11,635	11,641	11,640	11,641	11,635	11,645	12,079	12,300	12,082	12,088	12,085	12,732	143,203
	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		1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259	1,259	15,108
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		64,247	64,141	64,032	65,227	66,422	71,502	73,484	70,207	70,057	70,057	70,190	71,231	820,797
	a Recoverable Costs Allocated to Energy		64,247	64,141	64,032	65,227	66,422	71,502	73,484	70,207	70,057	70,057	70,190	71,231	820,797
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
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)		61,944	61,991	61,938	63,235	64,394	69,310	71,301	68,067	67,978	67,886	67,862	68,735	794,641
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)		61,944	61,991	61,938	63,235	64,394	69,310	71,301	68,067	67,978	67,886	67,862	68,735	794,641

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist, $2,232,602; Scholz $790,065; Smith $688,899; Daniel $586,912 Ending Balances: Crist, $2,232,602; Scholz $916,803; Smith $1,317,122; Daniel $581,275.
(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 Final True-Up 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	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	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)	(179,302)	(181,138)	(182,974)	(184,811)	(186,647)	(188,483)	(190,320)	(192,156)	(193,992)	(195,829)	(197,665)	(199,501)	(201,338)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	738,722	736,886	735,050	733,213	731,377	729,541	727,704	725,868	724,032	722,195	720,359	718,523	716,686	
6	Average Net Investment		737,805	735,969	734,132	732,296	730,460	728,623	726,787	724,951	723,114	721,278	719,442	717,605	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		5,420	5,407	5,393	5,380	5,367	5,354	5,340	5,327	5,313	5,300	5,285	5,272	64,158
	b Debt Component (Line 6 x Debt Component x 1/12)		1,539	1,536	1,532	1,529	1,524	1,521	1,517	1,513	1,509	1,506	1,502	1,497	18,225
8	Investment Expenses														
	a Depreciation (E)		1,836	1,836	1,837	1,836	1,836	1,837	1,836	1,836	1,837	1,836	1,836	1,837	22,036
	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)		8,795	8,779	8,762	8,745	8,727	8,712	8,693	8,676	8,659	8,642	8,623	8,606	104,419
	a Recoverable Costs Allocated to Energy		676	676	675	672	671	670	669	668	666	664	663	662	8,032
	b Recoverable Costs Allocated to Demand		8,119	8,103	8,087	8,073	8,056	8,042	8,024	8,008	7,993	7,978	7,960	7,944	96,387
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
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)		652	653	653	651	651	649	649	648	646	643	641	639	7,775
13	Retail Demand-Related Recoverable Costs (I)		7,828	7,813	7,798	7,784	7,768	7,754	7,737	7,721	7,707	7,693	7,675	7,660	92,938
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		8,480	8,466	8,451	8,435	8,419	8,403	8,386	8,369	8,353	8,336	8,316	8,299	100,713

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 Final True-Up 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	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	28	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	28	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)	242,944	242.944	242,944	242,944	242,944	242,944	242.944	242,972	242.972	242.972	242,972	242.972	242.972	
3	Less: Accumulated Depreciation (C)	(56.572)	(57,166)	(57.760)	(58,354)	(58.948)	(59,541)	(60.135)	(60.729)	(61,323)	(61,916)	(62,510)	(63,104)	(63.696)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	186,372	185,778	185,184	184.590	183,996	183,403	182.809	182,243	181,649	181,056	180.462	179,868	179,276	
6	Average Net Investment		186,075	185,481	184,887	184,293	183,700	183,106	182.526	181,946	181.353	180,759	180,165	179,573	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,367	1,362	1,359	1,354	1.350	1,346	1,341	1,337	1,332	1,328	1,323	1,319	16,118
	b Debt Component (Line 6 x Debt Component x 1/12)		388	387	386	385	384	382	381	379	378	378	376	375	4,579
8	Investment Expenses														
	a Depreciation (E)		594	594	594	594	593	594	594	594	593	594	594	592	7,124
	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	2,343	2.339	2.333	2.327	2.322	2,316	2.310	2,303	2.300	2,293	2,286	27,821
	a Recoverable Costs Allocated to Energy		181	181	180	179	179	178	178	178	178	177	176	176	2.141
	b Recoverable Costs Allocated to Demand		2.168	2,162	2,159	2.154	2,148	2,144	2.138	2.132	2.125	2,123	2,117	2,110	25,680
10	Energy Jurisdictional Factor		0 9634865	0 9658052	0.9666186	0 9687846	0 9687876	0 9686688	0 9696144	0 9688390	0 9696486	0 9683344	0 9661598	0 9642849	
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	175	174	174	174	173	173	173	173	172	170	170	2,076
13	Retail Demand-Related Recoverable Costs (I)		2,090	2,085	2,082	2.077	2,071	2,067	2,061	2,056	2,049	2,047	2,041	2,034	24,760
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,265	2,260	2,256	2,251	2,245	2,240	2,234	2,229	2,222	2,219	2,211	2,204	26,836

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning balances: Crist $149,921; Smith $93,023 Ending balances Crist $149,949; 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 Final True-Up 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	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		(5,004)	1,398	0	(251)	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)	512,169	507,003	508,239	508,077	507,664	507,502	507,340	507,178	507,016	506,854	506,692	506,530	506,368	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	512,169	507,003	508,239	508,077	507,664	507,502	507,340	507,178	507,016	506,854	506,692	506,530	506,368	
6	Average Net Investment		509,586	507,621	508,158	507,871	507,583	507,421	507,259	507,097	506,935	506,773	506,611	506,449	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		3,744	3,729	3,733	3,731	3,729	3,728	3,727	3,726	3,724	3,723	3,722	3,721	44,737
	b Debt Component (Line 6 x Debt Component x 1/12)		1,064	1,059	1,061	1,060	1,059	1,059	1,059	1,058	1,058	1,058	1,057	1,057	12,709
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)		4,970	4,950	4,956	4,953	4,950	4,949	4,948	4,946	4,944	4,943	4,941	4,940	59,390
	a Recoverable Costs Allocated to Energy		382	381	381	381	381	381	381	380	380	380	380	380	4,568
	b Recoverable Costs Allocated to Demand		4,588	4,569	4,575	4,572	4,569	4,568	4,567	4,566	4,564	4,563	4,561	4,560	54,822
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
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)		368	368	369	369	369	369	370	368	369	368	367	367	4,421
13	Retail Demand-Related Recoverable Costs (I)		4,424	4,406	4,411	4,408	4,406	4,405	4,404	4,403	4,401	4,400	4,398	4,397	52,863
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		4,792	4,774	4,780	4,777	4,775	4,774	4,774	4,771	4,770	4,768	4,765	4,764	57,284

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 Final True-Up 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	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	
3	Less: Accumulated Depreciation (C)	(136,087)	(136,901)	(137,715)	(138,530)	(139,344)	(140,158)	(140,973)	(141,787)	(142,601)	(143,416)	(144,230)	(145,044)	(145,859)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	169,236	168,422	167,608	166,793	165,979	165,165	164,350	163,536	162,722	161,907	161,093	160,279	159,464	
6	Average Net Investment		168,829	168,015	167,201	166,386	165,572	164,758	163,943	163,129	162,315	161,500	160,686	159,872	
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	1,204	1,199	1,193	1,187	1,181	1,175	14,489
	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	815	814	814	815	814	814	815	814	814	815	9,772
	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)		2,406	2,399	2,392	2,383	2,376	2,369	2,360	2,353	2,347	2,338	2,330	2,324	28,377
	a Recoverable Costs Allocated to Energy		185	185	184	183	183	182	182	181	181	180	179	179	2,184
	b Recoverable Costs Allocated to Demand		2,221	2,214	2,208	2,200	2,193	2,187	2,178	2,172	2,166	2,158	2,151	2,145	26,193
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
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	179	178	177	177	176	177	175	176	174	173	173	2,113
13	Retail Demand-Related Recoverable Costs (I)		2,142	2,135	2,129	2,121	2,115	2,109	2,100	2,094	2,088	2,081	2,074	2,068	25,256
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,320	2,314	2,307	2,298	2,292	2,285	2,277	2,269	2,264	2,255	2,247	2,241	27,369

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity 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 Final True-Up 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	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	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)	(24,418)	(24,602)	(24,786)	(24,970)	(25,154)	(25,338)	(25,522)	(25,706)	(25,890)	(26,074)	(26,257)	(26,441)	(26,624)	
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)	44,505	44,321	44,137	43,953	43,769	43,585	43,401	43,217	43,033	42,849	42,666	42,482	42,299	
6	Average Net Investment		44,413	44,229	44,045	43,861	43,677	43,493	43,309	43,125	42,941	42,758	42,574	42,391	
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	183	184	183	2,206
	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	586	586	582	7,119
	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	541	541	537	6,572
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
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	45	45	45	45	44	44	44	44	43	531
13	Retail Demand-Related Recoverable Costs (I)		537	535	534	532	530	529	526	526	525	522	522	518	6,336
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		581	579	578	577	575	574	571	570	569	566	566	561	6,867

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 Final True-Up 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	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	
3	Less: Accumulated Depreciation (C)	(45,171)	(45,442)	(45,713)	(45,983)	(46,254)	(46,525)	(46,795)	(47,066)	(47,337)	(47,607)	(47,878)	(48,149)	(48,419)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	56,324	56,053	55,782	55,512	55,241	54,970	54,700	54,429	54,158	53,888	53,617	53,346	53,076	
6	Average Net Investment		56,189	55,918	55,647	55,377	55,106	54,835	54,565	54,294	54,023	53,753	53,482	53,211	
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	270	271	271	270	271	271	270	271	271	270	3,248
	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	795	794	791	787	786	783	780	778	776	772	9,442
	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	734	733	730	726	726	723	720	718	716	713	8,716
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
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	708	707	704	700	700	697	694	692	690	687	8,404
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		773	771	767	766	763	759	758	755	752	750	748	744	9,106

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 Final True-Up 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	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	
3	*Less: Accumulated Depreciation (C)*	(26,818)	(26,977)	(27,136)	(27,295)	(27,454)	(27,613)	(27,772)	(27,931)	(28,090)	(28,249)	(28,407)	(28,566)	(28,724)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	32,725	32,566	32,407	32,248	32,089	31,930	31,771	31,612	31,453	31,294	31,136	30,977	30,819	
6	Average Net Investment		32,646	32,487	32,328	32,169	32,010	31,851	31,692	31,533	31,374	31,215	31,057	30,898	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		240	239	238	236	235	234	233	232	231	229	228	227	2,802
	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	158	159	158	1,906
	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	464	462	461	459	458	457	455	452	452	449	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	428	426	426	424	423	422	420	417	417	414	5,078
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
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	413	411	411	409	408	407	405	402	402	399	4,898
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		451	450	448	446	445	443	442	441	439	436	436	433	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 Final True-Up 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	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	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)	(48,220)	(49,201)	(50,182)	(51,163)	(52,144)	(53,125)	(54,106)	(55,087)	(56,068)	(57,049)	(58,029)	(59,010)	(59,991)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	342,899	341,918	340,937	339,956	338,975	337,994	337,013	336,032	335,051	334,070	333,090	332,109	331,128	
6	Average Net Investment		342,409	341,428	340,447	339,466	338,485	337,504	336,523	335,542	334,561	333,580	332,600	331,619	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,516	2,509	2,501	2,494	2,487	2,480	2,472	2,466	2,458	2,450	2,444	2,436	29,713
	b Debt Component (Line 6 x Debt Component x 1/12)		715	712	710	709	706	705	702	701	698	696	694	692	8,440
8	Investment Expenses														
	a Depreciation (E)		981	981	981	981	981	981	981	981	981	980	981	981	11,771
	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	4,192	4,184	4,174	4,166	4,155	4,148	4,137	4,126	4,119	4,109	49,924
	a Recoverable Costs Allocated to Energy		4,212	4,202	4,192	4,184	4,174	4,166	4,155	4,148	4,137	4,126	4,119	4,109	49,924
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
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)		4,061	4,061	4,055	4,056	4,047	4,038	4,032	4,022	4,014	3,998	3,982	3,965	48,331
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)		4,061	4,061	4,055	4,056	4,047	4,038	4,032	4,022	4,014	3,998	3,982	3,965	48,331

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 Final True-Up 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	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	
3	Less: Accumulated Depreciation (C)	(1,073,517)	(1,079,313)	(1,085,109)	(1,090,905)	(1,096,701)	(1,102,497)	(1,108,293)	(1,114,089)	(1,119,885)	(1,125,681)	(1,131,478)	(1,137,274)	(1,143,071)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	1,709,083	1,703,287	1,697,491	1,691,695	1,685,899	1,680,103	1,674,307	1,668,511	1,662,715	1,656,919	1,651,122	1,645,326	1,639,529	
6	Average Net Investment		1,706,185	1,700,389	1,694,593	1,688,797	1,683,001	1,677,205	1,671,409	1,665,613	1,659,817	1,654,021	1,648,224	1,642,428	
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	5,797	5,796	5,797	69,554
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	21,401	21,346	21,292	259,100
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	19,755	19,704	19,654	239,169
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
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	1,624	1,621	1,620	1,616	1,612	1,610	1,605	1,601	1,595	1,588	1,581	19,297
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	19,048	18,999	18,951	230,611
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		21,109	21,061	21,008	20,960	20,906	20,853	20,803	20,749	20,697	20,643	20,587	20,532	249,908

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

Docket No. 090007-EI
ECRC 2009 Final True-up
Exhibit RWD-1, Page 21 of 38

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up 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	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	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)	104,476	104,103	103,731	103,358	102,986	102,613	102,241	101,868	101,496	101,123	100,750	100,377	100,003	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	283,438	283,065	282,693	282,320	281,948	281,575	281,203	280,830	280,458	280,085	279,712	279,339	278,965	
6	Average Net Investment		283,252	282,879	282,507	282,134	281,762	281,389	281,017	280,644	280,272	279,899	279,526	279,153	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,081	2,079	2,075	2,073	2,070	2,067	2,065	2,062	2,059	2,057	2,054	2,051	24,793
	b Debt Component (Line 6 x Debt Component x 1/12)		591	591	589	588	588	587	586	586	585	584	584	582	7,041
8	Investment Expenses														
	a Depreciation (E)		373	372	373	372	373	372	373	372	373	373	373	374	4,473
	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	3,042	3,037	3,033	3,031	3,026	3,024	3,020	3,017	3,014	3,011	3,007	36,307
	a Recoverable Costs Allocated to Energy		235	234	233	233	233	232	232	232	232	232	231	231	2,790
	b Recoverable Costs Allocated to Demand		2,810	2,808	2,804	2,800	2,798	2,794	2,792	2,788	2,785	2,782	2,780	2,776	33,517
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
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)		227	226	225	226	226	225	225	225	225	225	223	223	2,701
13	Retail Demand-Related Recoverable Costs (I)		2,709	2,708	2,704	2,700	2,698	2,694	2,692	2,688	2,685	2,682	2,681	2,677	32,318
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,936	2,934	2,929	2,926	2,924	2,919	2,917	2,913	2,910	2,907	2,904	2,900	35,019

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 Final True-Up 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	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	394	10,061	0	72	(58)	2	(13)	
	b Clearings to Plant		0	0	0	0	0	0	0	0	10.527	(58)	2	(13)	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		835	2,423	554	0	639	0	427	(261)	4.498	7,161	2.180	2.870	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	16,193,793	16,193,793	16,193,793	16,193,793	16,193,793	16,193.793	16.193,793	16,193,793	16.193,793	16,204,320	16.204.262	16,204.264	16.204,251	
3	Less: Accumulated Depreciation (C)	(5,896,039)	(5.947,345)	(5,997,062)	(6,048,648)	(6,100,790)	(6,152,291)	(6,204,431)	(6,256,145)	(6,308,547)	(6,356,203)	(6,401,210)	(6.451.197)	(6.500,495)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	394	10,455	10,455	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	10,297,754	10,246.448	10.196,731	10.145,145	10,093,003	10.041,502	9,989,756	9,948,103	9,895.701	9,848,117	9,803,052	9,753,067	9,703,756	
6	Average Net Investment		10,272.101	10,221,590	10,170,938	10,119,074	10,067,253	10,015.629	9,968,930	9.921.902	9,871,909	9,825,585	9,778,060	9,728,412	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		75.469	75,098	74,726	74,345	73,964	73,584	73,242	72,896	72,529	72.189	71,839	71,474	881,355
	b Debt Component (Line 6 x Debt Component x 1/12)		21.438	21,333	21,227	21,119	21.010	20,902	20,805	20.707	20,603	20.506	20,407	20,303	250,360
8	Investment Expenses														
	a Depreciation (E)		41.829	41.828	41.828	41,830	41.828	41,828	41,829	41,829	41,842	41,856	41,855	41,856	502,038
	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		29,699	29,699	29,699	29,699	29,699	29,699	29,699	29.699	29.699	29,699	29,699	29,699	356.388
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		178,747	178,270	177,792	177,305	176,813	176,325	175,887	175,443	174,985	174,562	174,112	173,644	2,113,885
	a Recoverable Costs Allocated to Energy		13,750	13,713	13.677	13,639	13,601	13.563	13,530	13,496	13.460	13,428	13,393	13,358	162,608
	b Recoverable Costs Allocated to Demand		164,997	164.557	164,115	163,666	163,212	162,762	162,357	161.947	161.525	161,134	160.719	160,286	1.951,277
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0 9687876	0.9686688	0 9696144	0 9688390	0 9696486	0 9683344	0 9661598	0 9642849	
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)		13,257	13,253	13,230	13.223	13,186	13,147	13,128	13,085	13.061	13,012	12,949	12,890	157.421
13	Retail Demand-Related Recoverable Costs (I)		159,093	158,668	158,242	157,809	157,372	156,938	156.547	156.152	155,745	155.368	154,968	154,550	1,881.452
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		172.350	171,921	171,472	171,032	170.558	170,085	169,675	169.237	168,806	168,380	167,917	167.440	2,038,873

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

Docket No. 090007-EI
ECRC 2009 Final True-up
Exhibit RWD-1, Page 23 of 38

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up 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	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	
3	Less: Accumulated Depreciation (C)	(15,214)	(15,494)	(15,773)	(16,053)	(16,332)	(16,612)	(16,891)	(17,171)	(17,450)	(17,730)	(18,008)	(18,288)	(18,567)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	118,919	118,639	118,360	118,080	117,801	117,521	117,242	116,962	116,683	116,403	116,125	115,845	115,566	
6	Average Net Investment		118,779	118,500	118,220	117,941	117,661	117,382	117,102	116,823	116,543	116,265	115,985	115,706	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		872	870	869	867	864	863	861	858	856	855	852	850	10,337
	b Debt Component (Line 6 x Debt Component x 1/12)		248	248	246	246	246	245	245	243	243	243	242	242	2,937
8	Investment Expenses														
	a Depreciation (E)		280	279	280	279	280	279	280	279	280	278	280	279	3,353
	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)		1,400	1,397	1,395	1,392	1,390	1,387	1,386	1,380	1,379	1,376	1,374	1,371	16,627
	a Recoverable Costs Allocated to Energy		107	107	107	107	107	107	107	106	106	106	106	106	1,279
	b Recoverable Costs Allocated to Demand		1,293	1,290	1,288	1,285	1,283	1,280	1,279	1,274	1,273	1,270	1,268	1,265	15,348
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
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)		103	103	104	104	104	104	104	103	103	103	102	102	1,239
13	Retail Demand-Related Recoverable Costs (I)		1,247	1,244	1,242	1,239	1,237	1,234	1,233	1,228	1,227	1,225	1,223	1,220	14,799
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,350	1,347	1,346	1,343	1,341	1,338	1,337	1,331	1,330	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

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up 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	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	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		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
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 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 Final True-Up 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, 1287
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		15,772	686,332	2,518	(426)	581	4,004	(1,686)	575	2,636	(2,440)	(44,622)	304,513	
	b Clearings to Plant		15,772	1,150	61	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)	134,427,864	134,443,636	134,444,786	134,444,847	134,444,847	134,444,847	134,444,847	134,444,847	134,444,847	134,444,847	134,444,847	134,444,847	134,444,847	
3	Less: Accumulated Depreciation (C)	(12,843,244)	(13,232,242)	(13,621,263)	(14,010,286)	(14,399,308)	(14,788,331)	(15,177,354)	(15,566,377)	(15,955,399)	(16,344,422)	(16,733,445)	(17,122,468)	(17,511,490)	
4	CWIP - Non Interest Bearing	0	0	685,182	687,639	687,213	687,794	691,798	690,112	690,687	693,323	690,883	646,261	950,774	
5	Net Investment (Lines 2 + 3 + 4)	121,584,620	121,211,394	121,508,705	121,122,200	120,732,752	120,344,310	119,959,291	119,568,582	119,180,135	118,793,748	118,402,285	117,968,640	117,884,131	
6	Average Net Investment		121,398,007	121,360,050	121,315,453	120,927,476	120,538,531	120,151,801	119,763,937	119,374,359	118,986,942	118,598,017	118,185,463	117,926,386	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		891,912	891,632	891,306	888,454	885,595	882,755	879,906	877,044	874,197	871,340	868,308	866,405	10,568,854
	b Debt Component (Line 6 x Debt Component x 1/12)		253,358	253,279	253,185	252,376	251,564	250,756	249,948	249,134	248,326	247,514	246,653	246,112	3,002,205
8	Investment Expenses														
	a Depreciation (E)		358,026	358,049	358,051	358,051	358,051	358,051	358,051	358,051	358,051	358,051	358,051	358,051	4,296,585
	b Amortization (F)		2,292	2,292	2,292	2,291	2,292	2,292	2,292	2,291	2,292	2,292	2,292	2,291	27,501
	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)		1,534,268	1,533,932	1,533,514	1,529,852	1,526,182	1,522,534	1,518,877	1,515,200	1,511,546	1,507,877	1,503,984	1,501,539	18,239,305
	a Recoverable Costs Allocated to Energy		1,534,268	1,533,932	1,533,514	1,529,852	1,526,182	1,522,534	1,518,877	1,515,200	1,511,546	1,507,877	1,503,984	1,501,539	18,239,305
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
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)		1,479,281	1,482,517	1,483,361	1,483,135	1,479,581	1,475,864	1,473,756	1,469,012	1,466,694	1,461,151	1,454,106	1,448,925	17,657,383
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)		1,479,281	1,482,517	1,483,361	1,483,135	1,479,581	1,475,864	1,473,756	1,469,012	1,466,694	1,461,151	1,454,106	1,448,925	17,657,383

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

Docket No. 090007-EI
ECRC 2009 Final True-up
Exhibit RWD-1, Page 26 of 38

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2008 - December 2008

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 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)	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	919,836	
3	Less: Accumulated Depreciation (C)	(30,629)	(33,082)	(35,535)	(37,988)	(40,442)	(42,895)	(45,348)	(47,801)	(50,255)	(52,708)	(55,161)	(57,615)	(60,068)	
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)	889,207	886,754	884,301	881,848	879,394	876,941	874,488	872,035	869,581	867,128	864,675	862,221	859,768	
6	Average Net Investment		887,981	885,528	883,075	880,621	878,168	875,715	873,262	870,808	868,355	865,902	863,448	860,995	
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	1,822	1,817	1,812	1,807	1,802	1,797	21,900
8	Investment Expenses														
	a Depreciation (E)		2,453	2,453	2,453	2,454	2,453	2,453	2,453	2,454	2,453	2,453	2,454	2,453	29,439
	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	10,762	10,738	10,715	10,691	10,669	10,645	10,622	10,600	10,576	128,439
	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	9,934	9,912	9,891	9,869	9,848	9,826	9,805	9,785	9,762	118,559
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
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	803	803	803	801	799	798	796	795	792	788	785	9,566
13	Retail Demand-Related Recoverable Costs (I)		9,639	9,619	9,598	9,579	9,557	9,537	9,516	9,496	9,474	9,454	9,435	9,413	114,317
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		10,442	10,422	10,401	10,382	10,358	10,336	10,314	10,292	10,269	10,246	10,223	10,198	123,883

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

Docket No. 090007-EI
ECRC 2009 Final True-up
Exhibit RWD-1, Page 27 of 38

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up 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	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	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)	(7,895)	(8,063)	(8,231)	(8,398)	(8,566)	(8,734)	(8,901)	(9,069)	(9,237)	(9,404)	(9,572)	(9,740)	(9,907)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	54,975	54,807	54,639	54,472	54,304	54,136	53,969	53,801	53,633	53,466	53,298	53,130	52,963	
6	Average Net Investment		54,891	54,723	54,556	54,388	54,220	54,053	53,885	53,717	53,550	53,382	53,214	53,047	
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	167	168	168	167	168	168	167	168	168	167	2,012
	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	682	682	679	677	676	675	672	671	670	668	8,122
	a Recoverable Costs Allocated to Energy		686	684	682	682	679	677	676	675	672	671	670	668	8,122
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
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	661	660	661	658	656	656	654	652	650	648	645	7,862
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)		661	661	660	661	658	656	656	654	652	650	648	645	7,862

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 Final True-Up 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	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		2,535,141	2,977,155	2,109,373	1,109,428	336,771	63,963	47,649	50,433	59,512	(29,396)	8,342	(2,908)	
	b Clearings to Plant		18,648	(11,425)	12,355,971	1,109,428	336,771	63,963	47,649	50,433	59,512	(29,396)	8,342	(2,908)	
	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)	15,832,690	15,851,338	15,839,913	28,195,884	29,305,312	29,642,083	29,706,046	29,753,695	29,804,128	29,863,640	29,834,244	29,842,586	29,839,678	
3	Less: Accumulated Depreciation (C)	(701,457)	(734,635)	(767,826)	(817,473)	(885,079)	(954,611)	(1,024,678)	(1,094,893)	(1,165,242)	(1,235,737)	(1,306,272)	(1,376,778)	(1,447,293)	
4	CWIP - Non Interest Bearing	4,741,525	7,258,018	10,246,598	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	19,872,758	22,374,721	25,318,685	27,378,411	28,420,233	28,687,472	28,681,368	28,658,802	28,638,886	28,627,903	28,527,972	28,465,808	28,392,385	
6	Average Net Investment		21,123,740	23,846,703	26,348,548	27,899,322	28,553,853	28,684,420	28,670,085	28,648,844	28,633,395	28,577,938	28,496,890	28,429,097	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		155,196	175,202	193,583	204,976	209,787	210,744	210,639	210,484	210,369	209,962	209,367	208,868	2,409,177
	b Debt Component (Line 6 x Debt Component x 1/12)		44,086	49,768	54,990	58,227	59,592	59,865	59,835	59,789	59,758	59,642	59,472	59,332	684,356
8	Investment Expenses														
	a Depreciation (E)		33,178	33,191	49,647	67,606	69,532	70,067	70,215	70,349	70,495	70,535	70,506	70,515	745,836
	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)		232,460	258,161	298,220	330,809	338,911	340,676	340,689	340,622	340,622	340,139	339,345	338,715	3,839,369
	a Recoverable Costs Allocated to Energy		232,460	258,161	298,220	330,809	338,911	340,676	340,689	340,622	340,622	340,139	339,345	338,715	3,839,369
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
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)		224,129	249,508	288,467	320,707	328,563	330,233	330,568	330,239	330,515	329,599	328,091	326,846	3,717,465
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)		224,129	249,508	288,467	320,707	328,563	330,233	330,568	330,239	330,515	329,599	328,091	326,846	3,717,465

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist $0; Smith $15,715,200; Scholz $117,490 Ending Balances: Crist, $13,997,697; Smith $15,715,200; Scholz $126,781
(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 Final True-Up 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	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	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		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
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 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 Final True-Up Amount
January 2008 - December 2008

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Water Conservation Project
P.E.'s 1227 & 1298
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	73,956	
	b Clearings to Plant		0	0	0	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	73,956	
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	161,543	
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	124,690	
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	916	8,126
	b Debt Component (Line 6 x Debt Component x 1/12)		189	188	188	187	187	186	186	185	185	184	184	260	2,309
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)		1,104	1,101	1,099	1,096	1,094	1,091	1,090	1,087	1,085	1,082	1,080	1,426	13,435
	a Recoverable Costs Allocated to Energy		85	85	85	84	84	84	84	84	83	83	83	110	1,034
	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	1,316	12,401
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
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	82	81	81	80	80	106	999
13	Retail Demand-Related Recoverable Costs (I)		983	980	978	976	974	971	970	967	966	963	961	1,269	11,958
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,065	1,062	1,060	1,057	1,055	1,052	1,052	1,048	1,047	1,043	1,041	1,375	12,957

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 Final True-Up 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	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	14,165	429,961	(332,359)	10,372	8,916	997	9,263	
	b Clearings to Plant		0	0	0	0	0	0	357,658	(357,658)	0	0	132,052	9,263	
	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	6,185,365	5,827,707	5,827,707	5,827,707	5,959,759	5,969,022	
3	Less: Accumulated Depreciation (C)	(310,347)	(325,890)	(341,432)	(356,975)	(372,517)	(388,060)	(403,602)	(419,622)	(435,641)	(451,184)	(466,726)	(482,445)	(498,352)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	14,165	86,468	111,767	122,139	131,055	0	0	
5	Net Investment (Lines 2 + 3 + 4)	5,517,360	5,501,817	5,486,275	5,470,732	5,455,190	5,439,647	5,438,270	5,852,211	5,503,833	5,498,662	5,492,036	5,477,314	5,470,670	
6	Average Net Investment		5,509,589	5,494,046	5,478,504	5,462,961	5,447,419	5,438,959	5,645,241	5,678,022	5,501,248	5,495,349	5,484,675	5,473,992	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		40,479	40,365	40,251	40,136	40,022	39,960	41,476	41,716	40,417	40,374	40,296	40,218	485,710
	b Debt Component (Line 6 x Debt Component x 1/12)		11,499	11,466	11,434	11,401	11,369	11,351	11,782	11,850	11,481	11,469	11,446	11,425	137,973
8	Investment Expenses														
	a Depreciation (E)		15,543	15,542	15,543	15,542	15,543	15,542	16,020	16,019	15,543	15,542	15,719	15,907	188,005
	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)		67,521	67,373	67,228	67,079	66,934	66,853	69,278	69,585	67,441	67,385	67,461	67,550	811,688
	a Recoverable Costs Allocated to Energy		5,194	5,183	5,171	5,160	5,149	5,142	5,330	5,353	5,188	5,184	5,189	5,196	62,439
	b Recoverable Costs Allocated to Demand		62,327	62,190	62,057	61,919	61,785	61,711	63,948	64,232	62,253	62,201	62,272	62,354	749,249
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
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	5,002	5,002	4,992	4,984	5,172	5,190	5,034	5,023	5,017	5,014	60,447
13	Retail Demand-Related Recoverable Costs (I)		60,097	59,965	59,836	59,703	59,574	59,503	61,660	61,934	60,025	59,975	60,044	60,123	722,439
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		65,105	64,974	64,838	64,705	64,566	64,487	66,832	67,124	65,059	64,998	65,061	65,137	782,886

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

Docket No. 090007-EI
ECRC 2009 Final True-up
Exhibit RWD-1, Page 32 of 38

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2008 - December 2008

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, 1810, 1824, & 1826
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		830,025	331,656	719,566	16,357,754	3,012.664	3,258,228	911,121	1,643,992	2,038,220	97,002	2,273.958	3,217,262	
	b Clearings to Plant		40,901	285.642	86,162	15,188,343	2,209,064	612,699	9.917	538.595	43,048	(8,471)	1,019,078	10,825,472	
	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)	29,838,820	29,879,721	30,165,363	30,251,525	45,439,868	47,648,932	48,261,631	48,271,548	48,810,143	48,853,191	48,844,720	49,863,798	60,689,270	
3	Less: Accumulated Depreciation (C)	(487,156)	(566,022)	(645,303)	(725,183)	(825,566)	(949,149)	(1,076,496)	(1,204,675)	(1,333,799)	(1,463,912)	(1,594,074)	(1,725,427)	(1,870,105)	
4	CWIP - Non Interest Bearing	688,520	1,477,644	1,523,658	2,157,062	3,326,473	4,130,073	6,775,602	7,676,806	8,782,203	10,777,375	10,882,848	12,137,728	4,529,518	
5	Net Investment (Lines 2 + 3 + 4)	30,040,184	30,791,343	31,043,718	31,683,404	47,940,775	50,829,856	53,960,737	54,743,679	56,258,547	58,166,654	58,133,494	60,276,099	63,348,683	
6	Average Net Investment		30,415,764	30,917,531	31,363,561	39,812,090	49,385,316	52,395,297	54,352,208	55,501,113	57,212,601	58,150,074	59,204,797	61,812,391	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		223,464	227,152	230,425	292,498	362,834	384,948	399,324	407,768	420,342	427,228	434,975	454,135	4,265,093
	b Debt Component (Line 6 x Debt Component x 1/12)		63,478	64,525	65,456	83,088	103,066	109,348	113,431	115,831	119,401	121,360	123,561	129,003	1,211,548
8	Investment Expenses														
	a Depreciation (E)		78,408	78,823	79,422	99,925	123,125	126,889	127,721	128,666	129,655	129,704	130,895	144,220	1,377,453
	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)		365,808	370,958	375,761	475,969	589,483	621,643	640,934	652,723	669,856	678,750	689,889	727,816	6,859,590
	a Recoverable Costs Allocated to Energy		365,808	370,958	375,761	475,969	589,483	621,643	640,934	652,723	669,856	678,750	689,889	727,816	6,859,590
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
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)		352,698	358,524	363,472	461,434	571,484	602,588	621,894	632,826	649,980	657,717	667,010	702,313	6,641,940
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)		352,698	358,524	363,472	461,434	571,484	602,588	621,894	632,826	649,980	657,717	667,010	702,313	6,641,940

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Beginning Balances: Crist $29,626,570; Smith $212,250; Daniel $0, Scholz $0 Ending Balances: Crist $49,169,695; Smith $7,698,377, Daniel $3,264,866, Scholz $556,331
(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 Final True-Up 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	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	
3	Less: Accumulated Depreciation (C)	0	(394)	(788)	(1,182)	(1,577)	(1,971)	(2,365)	(2,759)	(3,154)	(3,548)	(3,942)	(4,336)	(4,731)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	23,654	23,260	22,866	22,472	22,077	21,683	21,289	20,895	20,500	20,106	19,712	19,318	18,923	
6	Average Net Investment		23,457	23,063	22,669	22,275	21,880	21,486	21,092	20,698	20,303	19,909	19,515	19,121	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		172	169	167	164	161	158	155	152	149	146	143	140	1,876
	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	395	394	394	394	395	394	394	394	395	4,731
	c Dismantlement		0	0	0	0	0	0	0	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	608	605	601	597	593	590	585	582	578	575	7,140
	a Recoverable Costs Allocated to Energy		47	47	47	47	46	46	46	45	45	45	44	44	549
	b Recoverable Costs Allocated to Demand		568	564	561	558	555	551	547	545	540	537	534	531	6,591
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
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	46	45	45	45	44	44	44	43	42	533
13	Retail Demand-Related Recoverable Costs (I)		548	544	541	538	535	531	527	525	521	518	515	512	6,355
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		593	589	586	584	580	576	572	569	565	562	558	554	6,888

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 Final True-Up Amount
January 2008 - December 2008

Return on Working Capital, Mercury Expenses
For Project: Mercury Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	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	0	0	0	0	0	0	0	0	0	0	0	0
	c SO2 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		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
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 Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

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 6A and 7A
(E) Line 8 is reported on Schedule 4A and 5A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2008 - December 2008

Return on Working Capital, Annual NOx Expenses
For Project: Annual NOx Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	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	0	0	0	0	0	0	0	0	0	0	0	0
	c SO2 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		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
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 Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

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 6A and 7A
(E) Line 8 is reported on Schedule 4A and 5A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2008 - December 2008

Return on Working Capital, Seasonal NOx Expenses
For Project: Seasonal NOx Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	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	0	0	0	0	0	0	0	0	0	0	0	0
	c SO2 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		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
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 Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

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 6A and 7A
(E) Line 8 is reported on Schedule 4A and 5A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2008 - December 2008

Return on Working Capital, SO2 Expenses
For Project: SO2 Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	427,351	(38,638)	40,559	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	14,376,402	13,804,389	13,285,714	12,778,314	12,260,506	11,763,103	11,130,296	10,412,487	9,738,797	9,143,964	8,733,817	8,324,799	7,911,392	
	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	(1,042,409)	(1,034,188)	(1,025,967)	(1,017,746)	(1,009,525)	(1,389,039)	(1,308,084)	(1,299,566)	(1,250,489)	(1,201,412)	(1,152,335)	(1,103,258)	(1,054,181)	
3	Total Working Capital Balance	13,333,993	12,770,201	12,259,747	11,760,568	11,250,981	10,374,064	9,822,212	9,112,921	8,488,308	7,942,552	7,581,482	7,221,541	6,857,211	
4	Average Net Working Capital Balance		13,052,097	12,514,974	12,010,157	11,505,774	10,812,522	10,098,138	9,467,566	8,800,614	8,215,430	7,762,017	7,401,511	7,039,376	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		95,894	91,948	88,239	84,533	79,440	74,191	69,558	64,658	60,359	57,028	54,379	51,718	871,945
	b Debt Component (Line 4 x Debt Component x 1/12)		27,240	26,119	25,065	24,013	22,566	21,075	19,759	18,367	17,146	16,199	15,447	14,691	247,687
6	Total Return Component (D)		123,134	118,067	113,304	108,546	102,006	95,266	89,317	83,025	77,505	73,227	69,826	66,409	1,119,632
7	Expenses														
	a Gains		(8,221)	(8,221)	(8,221)	(8,221)	(47,837)	(42,317)	(49,077)	(49,077)	(49,077)	(49,077)	(49,077)	(49,077)	(417,500)
	b Losses		0	0	0	0	0	0	0	0	0	0	0		0
	c SO2 Allowance Expense		572,013	518,675	507,400	517,808	497,403	632,807	717,809	673,690	594,833	410,147	409,018	413,407	6,465,010
8	Net Expenses (E)		563,792	510,454	499,179	509,587	449,566	590,490	668,732	624,613	545,756	361,070	359,941	364,330	6,047,510
9	Total System Recoverable Expenses (Lines 6 + 8)		686,926	628,521	612,483	618,133	551,572	685,756	758,049	707,638	623,261	434,297	429,767	430,739	7,167,142
	a Recoverable Costs Allocated to Energy		686,926	628,521	612,483	618,133	551,572	685,756	758,049	707,638	623,261	434,297	429,767	430,739	7,167,142
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9634865	0.9658052	0.9666186	0.9687846	0.9687876	0.9686688	0.9696144	0.9688390	0.9696486	0.9683344	0.9661598	0.9642849	
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)		662,307	607,454	592,452	599,257	534,730	664,735	735,530	686,067	604,767	420,839	415,514	415,646	6,939,298
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)		662,307	607,454	592,452	599,257	534,730	664,735	735,530	686,067	604,767	420,839	415,514	415,646	6,939,298

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 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 2009 - December 2009

Line		Period Amount ($)
1	Over/(Under) Recovery for the current period (Schedule 2E, Line 5)	380,995
2	Interest Provision (Schedule 2E, Line 6)	24,132
3	Current Period True-Up Amount to be refunded/(recovered) in the projection period January 2010 - December 2010 (Lines 1 + 2)	405,127

Schedule 2E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2009 - December 2009

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)	6,067,061	5,402,835	5,434,031	5,599,141	6,665,802	8,490,566	8,338,461	8,318,469	7,134,880	6,129,612	5,412,518	6,256,549	79,249,926
2	True-Up Provision (Order No. PSC-08-0775-FOF-EI)	(111,652)	(111,652)	(111,652)	(111,652)	(111,652)	(111,652)	(111,652)	(111,652)	(111,652)	(111,652)	(111,652)	(111,653)	(1,339,820)
3	**ECRC Revenues Applicable to Period (Lines 1 + 2)**	5,955,410	5,291,184	5,322,379	5,487,490	6,554,150	8,378,914	8,226,809	8,206,817	7,023,228	6,017,960	5,300,866	6,144,896	77,910,106
4	Jurisdictional ECRC Costs													
a	O & M Activities (Schedule 5E, Line 9)	349,748	1,311,706	1,180,305	1,459,214	2,241,236	2,503,337	3,744,465	4,093,259	4,384,950	3,504,031	3,587,058	4,576,384	32,935,693
b	Capital Investment Projects (Schedule 7E, Line 9)	3,261,259	3,288,480	3,353,293	3,421,103	3,457,904	3,535,159	3,597,454	3,571,015	3,536,508	3,501,391	3,474,184	6,595,668	44,593,418
c	**Total Jurisdictional ECRC Costs**	3,611,007	4,600,186	4,533,598	4,880,317	5,699,140	6,038,496	7,341,919	7,664,274	7,921,458	7,005,422	7,061,242	11,172,052	77,529,111
5	**Over/(Under) Recovery (Line 3 - Line 4c)**	2,344,403	690,998	788,781	607,173	855,010	2,340,418	884,890	542,543	(898,230)	(987,462)	(1,760,376)	(5,027,156)	380,995
6	Interest Provision (Schedule 3E, Line 10)	703	1,862	2,034	1,808	1,580	1,930	2,583	2,825	2,806	2,565	2,197	1,239	24,132
7	Beginning Balance True-Up & Interest Provision													
a	Actual Total for True-Up Period 2008	(1,428,879)	1,027,879	1,832,390	2,734,857	3,455,489	4,423,731	6,877,731	7,876,856	8,533,876	7,750,104	6,876,859	5,230,332	(1,428,879)
b	Final True-Up from January 2007 - December 2007 (Order No. PSC-08-0775-FOF-EI)	1,470,471	1,470,471	1,470,471	1,470,471	1,470,471	1,470,471	1,470,471	1,470,471	1,470,471	1,470,471	1,470,471	1,470,471	1,470,471
8	True-Up Collected/(Refunded) (see Line 2)	111,652	111,652	111,652	111,652	111,652	111,652	111,652	111,652	111,652	111,652	111,652	111,653	1,339,820
9	Adjustments													
10	End of Period Total True-Up (Lines 5 + 6 + 7a + 7b + 8)	2,498,350	3,302,861	4,205,328	4,925,960	5,894,202	8,348,202	9,347,327	10,004,347	9,220,575	8,347,330	6,700,803	1,786,539	1,786,539

Schedule 3E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2009 - December 2009

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)	41,592	2,498,350	3,302,861	4,205,328	4,925,960	5,894,202	8,348,202	9,347,327	10,004,347	9,220,575	8,347,330	6,700,803	
2	Ending True-Up Amount Before Interest (Line 1 + Schedule 2E, Lines 5 + 8)	2,497,647	3,300,999	4,203,294	4,924,152	5,892,622	8,346,272	9,344,744	10,001,522	9,217,769	8,344,765	6,698,606	1,785,300	
3	Total of Beginning & Ending True-up (Lines 1 + 2)	2,539,239	5,799,348	7,506,154	9,129,479	10,818,582	14,240,474	17,692,946	19,348,849	19,222,116	17,565,340	15,045,936	8,486,103	
4	Average True-Up Amount (Line 3 x 1/2)	1,269,619	2,899,674	3,753,077	4,564,740	5,409,291	7,120,237	8,846,473	9,674,424	9,611,058	8,782,670	7,522,968	4,243,051	
5	Interest Rate (First Day of Reporting Business Month)	0.005400	0.007900	0.007500	0.005500	0.004000	0.003000	0.003500	0.003500	0.003500	0.003500	0.003500	0.003500	
6	Interest Rate (First Day of Subsequent Business Month)	0.007900	0.007500	0.005500	0.004000	0.003000	0.003500	0.003500	0.003500	0.003500	0.003500	0.003500	0.003500	
7	Total of Beginning and Ending Interest Rates (Line 5 + Line 6)	0.013300	0.015400	0.013000	0.009500	0.007000	0.006500	0.007000	0.007000	0.007000	0.007000	0.007000	0.007000	
8	Average Interest Rate (Line 7 x 1/2)	0.006650	0.007700	0.006500	0.004750	0.003500	0.003250	0.003500	0.003500	0.003500	0.003500	0.003500	0.003500	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.000554	0.000642	0.000542	0.000396	0.000292	0.000271	0.000292	0.000292	0.000292	0.000292	0.000292	0.000292	
10	Interest Provision for the Month (Line 4 x Line 9)	703	1,862	2,034	1,808	1,580	1,930	2,583	2,825	2,806	2,565	2,197	1,239	24,132

Schedule 4E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2009 - December 2009

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	896,914	964,374	(67,460)	(7.0) %
	.3 Title V	117,587	129,352	(11,765)	(9.1) %
	.4 Asbestos Fees	3,404	2,500	904	36.2 %
	.5 Emission Monitoring	609,314	656,209	(46,895)	(7.1) %
	.6 General Water Quality	585,921	556,074	29,847	5.4 %
	.7 Groundwater Contamination Investigation	1,548,387	1,631,176	(82,789)	(5.1) %
	.8 State NPDES Administration	46,062	42,000	4,062	9.7 %
	.9 Lead and Copper Rule	15,989	20,400	(4,411)	(21.6) %
	.10 Env Auditing/Assessment	12,226	7,300	4,926	67.5 %
	.11 General Solid & Hazardous Waste	481,274	417,471	63,803	15.3 %
	.12 Above Ground Storage Tanks	56,237	90,100	(33,863)	(37.6) %
	.13 Low Nox	0	0	0	0.0 %
	.14 Ash Pond Diversion Curtains	1,003,700	800,000	203,700	25.5 %
	.15 Mercury Emissions	0	0	0	0.0 %
	.16 Sodium Injection	175,841	313,000	(137,159)	(43.8) %
	.17 Gulf Coast Ozone Study	0	0	0	0.0 %
	.18 SPCC Substation Project	(27,395)	0	(27,395)	0.0 %
	.19 FDEP NOX Reduction Agreement	2,442,072	4,168,665	(1,726,593)	(41.4) %
	.20 CAIR/CAMR/CAVR Compliance Program	2,738,176	5,972,528	(3,234,352)	(54.2) %
	.21 Mercury Allowances	0	0	0	0.0 %
	.22 Annual NOx Allowances	16,976,956	18,635,785	(1,658,829)	(8.9) %
	.23 Seasonal NOx Allowances	964,576	2,154,990	(1,190,414)	(55.2) %
	.24 SO2 Allowances	5,420,531	5,912,773	(492,242)	(8.3) %
2	Total O & M Activities	34,067,772	42,474,697	(8,406,925)	(19.8) %
3	Recoverable Costs Allocated to Energy	31,345,667	39,707,676	(8,362,009)	(21.1) %
4	Recoverable Costs Allocated to Demand	2,722,105	2,767,020	(44,915)	(1.6) %

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-08-0775-FOF-EI
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2009 - December 2009

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	-	772,540	-	-	-	-	-	-	-	-	124,374	-	896,914	0	896,914
.3	Title V	8,338	6,559	7,489	10,925	6,205	10,154	17,944	9,190	9,620	9,696	10,885	10,582	117,587	0	117,587
.4	Asbestos Fees	1,500	-	904	-	-	-	-	-	-	-	-	1,000	3,404	3,404	0
.5	Emission Monitoring	37,623	44,799	46,766	19,604	72,503	45,319	56,078	57,740	55,535	57,447	52,097	63,803	609,314	0	609,314
.6	General Water Quality	13,930	18,674	25,203	16,026	12,442	70,228	60,743	70,345	90,695	102,745	68,345	36,545	585,921	585,921	0
.7	Groundwater Contamination Investigation	59,115	83,125	91,563	43,612	66,587	380,863	94,957	78,733	413,633	78,733	78,733	78,733	1,548,387	1,548,387	0
.8	State NPDES Administration	-	4,062	-	-	-	-	-	-	-	-	7,500	34,500	46,062	46,062	0
.9	Lead and Copper Rule	-	36	-	-	3,953	-	-	4,000	-	4,000	-	4,000	15,989	15,989	0
.10	Env Auditing/Assessment	3	31	6,955	-	4,647	2,401	(3,111)	-	650	-	-	650	12,226	12,226	0
.11	General Solid & Hazardous Waste	40,996	26,760	53,760	93,690	734	58,426	40,896	32,013	34,744	32,745	32,746	33,764	481,274	481,274	0
.12	Above Ground Storage Tanks	780	2,236	1,540	4,328	1,528	(1,035)	3,000	1,500	30,860	2,500	7,500	1,500	56,237	56,237	0
.13	Low Nox	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
.14	Ash Pond Diversion Curtains	-	-	-	-	-	-	-	170,200	318,000	159,000	356,500	-	1,003,700	0	1,003,700
.15	Mercury Emissions	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
.16	Sodium Injection	18,564	9,147	10,987	9,787	17,543	8,563	20,000	12,750	21,500	13,000	20,500	13,500	175,841	0	175,841
.17	Gulf Coast Ozone Study	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
.18	SPCC Substation Project	(27,395)	-	-	-	-	-	-	-	-	-	-	-	(27,395)	(27,395)	0
.19	FDEP NOX Reduction Agreement	(9,942)	178,291	226,174	67,132	149,524	100,177	186,657	197,884	200,759	669,633	269,191	206,592	2,442,072	0	2,442,072
.20	CAIR/CAMR/CAVR Compliance Program	33,823	108,098	10,403	25,120	98,959	128,283	164,001	162,593	162,656	164,156	222,656	1,457,428	2,738,176	0	2,738,176
.21	Mercury Allowances	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
.22	Annual NOx Allowances	-	-	574,101	1,035,552	1,370,250	1,335,942	2,167,270	2,367,617	2,192,942	1,868,272	1,963,205	2,101,806	16,976,956	0	16,976,956
.23	Seasonal NOx Allowances	-	-	-	-	182,048	161,239	212,318	212,318	196,654	-	-	-	964,576	0	964,576
.24	SO2 Allowances	185,350	105,270	165,326	180,777	326,980	284,560	846,383	853,399	804,290	465,051	504,768	698,377	5,420,531	0	5,420,531
2	Total of O & M Activities	362,685	1,359,628	1,221,171	1,506,553	2,313,902	2,585,120	3,867,136	4,230,282	4,532,538	3,626,978	3,719,000	4,742,780	34,067,772	2,722,105	31,345,667
3	Recoverable Costs Allocated to Energy	273,756	1,224,704	1,041,246	1,348,897	2,224,011	2,074,237	3,670,651	4,043,691	3,961,956	3,406,255	3,524,176	4,552,088	31,345,667		
4	Recoverable Costs Allocated to Demand	88,929	134,924	179,925	157,656	89,891	510,883	196,485	186,591	570,582	220,723	194,824	190,692	2,722,105		
5	Retail Energy Jurisdictional Factor	0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705			
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)	264,001	1,181,610	1,006,818	1,307,200	2,154,562	2,010,735	3,555,011	3,913,345	3,834,786	3,291,206	3,399,206	4,392,516	30,310,996		
8	Jurisdictional Demand Recoverable Costs (B)	85,747	130,096	173,487	152,014	86,674	492,602	189,454	179,914	550,164	212,825	187,852	183,868	2,624,697		
9	Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8)	349,748	1,311,706	1,180,305	1,459,214	2,241,236	2,503,337	3,744,465	4,093,259	4,384,950	3,504,031	3,587,058	4,576,384	32,935,693		

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 2009 - December 2009

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	42,783	42,783	0	0.0	%
.2	Crist 5, 6 & 7 Precipitator Projects	1,875,933	1,946,449	(70,516)	(3.6)	%
.3	Crist 7 Flue Gas Conditioning	168,416	168,416	0	0.0	%
.4	Low NOx Burners, Crist 6 & 7	2,019,321	2,019,321	0	0.0	%
.5	CEMS - Plants Crist, Scholz, Smith, & Daniel	924,002	873,071	50,931	5.8	%
.6	Sub. Contam. Mobile Groundwater Treat. Sys.	101,917	101,919	(2)	(0.0)	%
.7	Raw Water Well Flowmeters - Plants Crist & Smith	27,019	27,017	2	0.0	%
.8	Crist Cooling Tower Cell	59,161	59,161	0	0.0	%
.9	Crist 1-5 Dechlorination	27,271	27,271	0	0.0	%
.10	Crist Diesel Fuel Oil Remediation	6,872	6,872	0	0.0	%
.11	Crist Bulk Tanker Unload Sec Contain Struc	9,076	9,076	0	0.0	%
.12	Crist IWW Sampling System	5,289	5,286	3	0.1	%
.13	Sodium Injection System	48,595	48,595	0	0.0	%
.14	Smith Stormwater Collection System	251,223	251,224	(1)	(0.0)	%
.15	Smith Waste Water Treatment Facility	35,800	35,802	(2)	(0.0)	%
.16	Daniel Ash Management Project	2,101,686	2,079,731	21,955	1.1	%
.17	Smith Water Conservation	16,251	16,253	(2)	(0.0)	%
.18	Underground Fuel Tank Replacement	0	0	0	0.0	%
.19	Crist FDEP Agreement for Ozone Attainment	17,818,659	17,944,006	(125,347)	(0.7)	%
.20	SPCC Compliance	126,250	128,006	(1,756)	(1.4)	%
.21	Crist Common FTIR Monitor	7,899	7,897	2	0.0	%
.22	Precipitator Upgrades for CAM Compliance	4,012,474	4,001,988	10,486	0.3	%
.23	Plant Groundwater Investigation	0	0	0	0.0	%
.24	Crist Water Conservation	59,899	38,538	21,361	55.4	%
.25	Crist Condenser Tubes	799,655	800,840	(1,185)	(0.1)	%
.26	CAIR/CAMR/CAVR Compliance	13,474,791	13,413,321	61,470	0.5	%
.27	General Water Quality	6,604	6,604	0	0.0	%
.28	Mercury Allowances	0	0	0	100.0	%
.29	Annual Nox Allowances	977,343	196,948	780,395	396.2	%
.30	Seasonal Nox Allowances	43,104	121,722	(78,618)	(64.6)	%
.31	SO2 Allowances	1,085,788	936,401	149,387	16.0	%
2	Total Investment Projects - Recoverable Costs	46,133,081	45,314,518	818,563	1.8	%
3	Recoverable Costs Allocated to Energy	42,778,646	3,317,168	39,461,478	1,189.6	%
4	Recoverable Costs Allocated to Demand	3,354,435	41,997,350	(38,642,915)	(92.0)	%

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-08-0775-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 2009 - December 2009

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	3,702	3,676	3,652	3,627	3,603	3,577	3,553	3,528	3,504	3,478	3,454	3,429	42,783	0	42,783
.2	Crist 5, 6 & 7 Precipitator Projects	158,837	158,363	157,890	157,460	157,042	156,596	156,140	155,667	155,194	154,721	154,248	153,775	1,875,933	0	1,875,933
.3	Crist 7 Flue Gas Conditioning	14,045	14,044	14,041	14,040	14,037	14,036	14,033	14,032	14,030	14,028	14,026	14,024	168,416	0	168,416
.4	Low NOx Burners, Crist 6 & 7	169,536	169,307	169,078	168,849	168,620	168,391	168,162	167,934	167,704	167,475	167,247	167,018	2,019,321	0	2,019,321
.5	CEMS - Plants Crist, Scholz, Smith, & Daniel	72,176	71,950	71,961	75,279	78,366	78,279	78,186	78,163	78,139	79,215	80,775	81,513	924,002	0	924,002
.6	Sub. Contam. Mobile Groundwater Treat. Sys.	8,588	8,571	8,553	8,536	8,519	8,501	8,484	8,468	8,450	8,433	8,415	8,399	101,917	94,077	7,840
.7	Raw Water Well Flowmeters - Plants Crist & Smith	2,282	2,276	2,271	2,266	2,261	2,254	2,249	2,244	2,237	2,233	2,226	2,220	27,019	24,940	2,079
.8	Crist Cooling Tower Cell	4,939	4,937	4,935	4,934	4,932	4,931	4,930	4,927	4,926	4,925	4,923	4,922	59,161	54,609	4,552
.9	Crist 1-5 Dechlorination	2,315	2,307	2,300	2,292	2,284	2,276	2,269	2,261	2,253	2,246	2,238	2,230	27,271	25,173	2,098
.10	Crist Diesel Fuel Oil Remediation	582	581	578	577	576	573	572	570	568	567	565	563	6,872	6,344	528
.11	Crist Bulk Tanker Unload Sec Contain Struc	770	768	765	763	760	758	755	753	750	747	745	742	9,076	8,379	697
.12	Crist IWW Sampling System	449	448	446	444	443	441	440	439	437	435	434	433	5,289	4,883	406
.13	Sodium Injection System	4,100	4,091	4,082	4,073	4,063	4,054	4,045	4,036	4,027	4,017	4,008	3,999	48,595	0	48,595
.14	Smith Stormwater Collection System	21,236	21,182	21,126	21,072	21,017	20,962	20,908	20,853	20,799	20,744	20,689	20,635	251,223	231,899	19,324
.15	Smith Waste Water Treatment Facility	3,002	2,999	2,996	2,992	2,989	2,985	2,982	2,979	2,974	2,971	2,967	2,964	35,800	33,045	2,755
.16	Daniel Ash Management Project	170,772	170,341	170,991	172,953	174,618	177,068	178,700	178,221	177,743	177,251	176,760	176,268	2,101,686	1,940,018	161,668
.17	Smith Water Conservation	1,369	1,366	1,364	1,361	1,358	1,356	1,353	1,350	1,348	1,345	1,342	1,339	16,251	15,001	1,250
.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	1,499,307	1,497,442	1,496,511	1,493,487	1,490,774	1,488,340	1,484,655	1,480,981	1,477,304	1,473,629	1,469,953	1,466,276	17,818,659	0	17,818,659
.20	SPCC Compliance	10,553	10,530	10,553	10,576	10,552	10,530	10,517	10,503	10,479	10,456	10,469	10,532	126,250	116,538	9,712
.21	Crist Common FTIR Monitor	667	665	664	662	661	659	657	656	655	652	651	650	7,899	0	7,899
.22	Precipitator Upgrades for CAM Compliance	338,031	337,366	336,701	336,036	335,371	334,706	334,040	333,375	332,710	332,045	331,379	330,714	4,012,474	0	4,012,474
.23	Plant Groundwater Investigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
.24	Crist Water Conservation	1,076	1,073	1,070	1,068	1,065	1,063	1,061	1,059	1,056	1,054	1,051	48,203	59,899	55,291	4,608
.25	Crist Condenser Tubes	67,496	67,347	67,157	67,006	66,856	66,706	66,556	66,407	66,256	66,106	65,956	65,806	799,655	738,142	61,513
.26	CAIR/CAMR/CAVR Compliance	761,583	760,846	765,411	805,850	848,846	877,137	901,690	904,610	905,601	905,965	910,509	4,126,743	13,474,791	0	13,474,791
.27	General Water Quality	571	567	563	560	556	552	548	544	541	538	534	530	6,604	6,096	508
.28	Mercury Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
.29	Annual Nox Allowances	0	33,094	87,077	105,853	104,934	118,813	130,886	119,105	97,593	78,436	60,363	41,189	977,343	0	977,343
.30	Seasonal Nox Allowances	0	0	4,820	9,688	8,877	7,258	5,496	3,493	1,564	636	636	636	43,104	0	43,104
.31	SO2 Allowances	63,817	62,445	61,169	59,307	56,682	95,485	131,840	123,821	116,002	110,015	105,440	99,765	1,085,788	0	1,085,788
2	Total Investment Projects - Recoverable Costs	3,381,801	3,408,582	3,468,725	3,531,611	3,570,662	3,648,287	3,715,707	3,690,979	3,654,844	3,624,363	3,602,003	6,835,517	46,133,081	3,354,435	42,778,646
3	Recoverable Costs Allocated to Energy	3,108,572	3,136,005	3,195,798	3,257,087	3,294,860	3,370,480	3,436,639	3,412,598	3,377,169	3,347,394	3,325,714	6,516,330	42,778,646		
4	Recoverable Costs Allocated to Demand	273,229	272,577	272,927	274,524	275,802	277,807	279,068	278,381	277,675	276,969	276,289	319,187	3,354,435		
5	Retail Energy Jurisdictional Factor	0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705			
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)	2,997,807	3,025,657	3,090,132	3,156,403	3,191,971	3,267,293	3,328,372	3,302,596	3,268,769	3,234,333	3,207,782	6,287,903	41,359,018		
8	Jurisdictional Demand Recoverable Costs (C)	263,452	262,823	263,161	264,700	265,933	267,866	269,082	268,419	267,739	267,058	266,402	307,765	3,234,400		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	3,261,259	3,288,480	3,353,293	3,421,103	3,457,904	3,535,159	3,597,454	3,571,015	3,536,508	3,501,391	3,474,184	6,595,668	44,593,418		

Notes:

(A) Pages 1-27 of Schedule 8E, Line 9, Pages 28-31 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 2009 - December 2009

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)	(104,682)	(107,305)	(109,928)	(112,551)	(115,174)	(117,797)	(120,420)	(123,043)	(125,666)	(128,289)	(130,912)	(133,535)	(136,158)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	115,612	112,989	110,366	107,743	105,120	102,497	99,874	97,251	94,628	92,005	89,382	86,759	84,136	
6	Average Net Investment		114,301	111,678	109,055	106,432	103,809	101,186	98,563	95,940	93,317	90,694	88,071	85,448	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		840	820	801	782	763	743	724	705	686	666	647	628	8,805
	b Debt Component (Line 6 x Debt Component x 1/12)		239	233	228	222	217	211	206	200	195	189	184	178	2,502
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)		3,702	3,676	3,652	3,627	3,603	3,577	3,553	3,528	3,504	3,478	3,454	3,429	42,783
	a Recoverable Costs Allocated to Energy		3,702	3,676	3,652	3,627	3,603	3,577	3,553	3,528	3,504	3,478	3,454	3,429	42,783
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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)		3,570	3,547	3,531	3,515	3,490	3,467	3,441	3,414	3,392	3,361	3,332	3,309	41,369
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		3,570	3,547	3,531	3,515	3,490	3,467	3,441	3,414	3,392	3,361	3,332	3,309	41,369

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity 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

Schedule 8E
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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2009 - December 2009

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	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	8,988	2,545	3,452	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)	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	
3	Less: Accumulated Depreciation (C)	(2,984,218)	(3,034,350)	(3,084,482)	(3,134,614)	(3,175,758)	(3,223,345)	(3,270,025)	(3,320,157)	(3,370,289)	(3,420,421)	(3,470,553)	(3,520,685)	(3,570,817)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	11,547,661	11,497,529	11,447,397	11,397,265	11,356,121	11,308,534	11,261,854	11,211,722	11,161,590	11,111,458	11,061,326	11,011,194	10,961,062	
6	Average Net Investment		11,522,595	11,472,463	11,422,331	11,376,693	11,332,328	11,285,194	11,236,788	11,186,656	11,136,524	11,086,392	11,036,260	10,986,128	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		84,657	84,288	83,920	83,585	83,259	82,912	82,557	82,188	81,820	81,452	81,083	80,715	992,436
	b Debt Component (Line 6 x Debt Component x 1/12)		24,048	23,943	23,838	23,743	23,651	23,552	23,451	23,347	23,242	23,137	23,033	22,928	281,913
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)		158,837	158,363	157,890	157,460	157,042	156,596	156,140	155,667	155,194	154,721	154,248	153,775	1,875,933
	a Recoverable Costs Allocated to Energy		158,837	158,363	157,890	157,460	157,042	156,596	156,140	155,667	155,194	154,721	154,248	153,775	1,875,933
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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)		153,177	152,791	152,670	152,594	152,138	151,802	151,221	150,649	150,213	149,495	148,778	148,384	1,813,912
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)		153,177	152,791	152,670	152,594	152,138	151,802	151,221	150,649	150,213	149,495	148,778	148,384	1,813,912

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

Schedule 8E
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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2009 - December 2009

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)	1,467,272	1,467,068	1,466,864	1,466,660	1,466,456	1,466,252	1,466,048	1,465,844	1,465,640	1,465,436	1,465,232	1,465,028	1,464,824	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	1,467,272	1,467,068	1,466,864	1,466,660	1,466,456	1,466,252	1,466,048	1,465,844	1,465,640	1,465,436	1,465,232	1,465,028	1,464,824	
6	Average Net Investment		1,467,170	1,466,966	1,466,762	1,466,558	1,466,354	1,466,150	1,465,946	1,465,742	1,465,538	1,465,334	1,465,130	1,464,926	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		10,779	10,778	10,776	10,775	10,773	10,772	10,770	10,769	10,767	10,766	10,764	10,763	129,252
	b Debt Component (Line 6 x Debt Component x 1/12)		3,062	3,062	3,061	3,061	3,060	3,060	3,059	3,059	3,059	3,058	3,058	3,057	36,716
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)		14,045	14,044	14,041	14,040	14,037	14,036	14,033	14,032	14,030	14,028	14,026	14,024	168,416
	a Recoverable Costs Allocated to Energy		14,045	14,044	14,041	14,040	14,037	14,036	14,033	14,032	14,030	14,028	14,026	14,024	168,416
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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)		13,545	13,550	13,577	13,606	13,599	13,606	13,591	13,580	13,580	13,554	13,529	13,532	162,849
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)		13,545	13,550	13,577	13,606	13,599	13,606	13,591	13,580	13,580	13,554	13,529	13,532	162,849

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 2009 - December 2009

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		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	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)	6,312,945	6,288,681	6,264,417	6,240,153	6,215,889	6,191,625	6,167,361	6,143,097	6,118,833	6,094,569	6,070,305	6,046,041	6,021,777	
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)	15,410,868	15,386,604	15,362,340	15,338,076	15,313,812	15,289,548	15,265,284	15,241,020	15,216,756	15,192,492	15,168,228	15,143,964	15,119,700	
6	Average Net Investment		15,398,736	15,374,472	15,350,208	15,325,944	15,301,680	15,277,416	15,253,152	15,228,888	15,204,624	15,180,360	15,156,096	15,131,832	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		113,135	112,956	112,778	112,600	112,421	112,243	112,065	111,887	111,708	111,530	111,352	111,174	1,345,849
	b Debt Component (Line 6 x Debt Component x 1/12)		32,137	32,087	32,036	31,985	31,935	31,884	31,833	31,783	31,732	31,681	31,631	31,580	382,304
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)		169,536	169,307	169,078	168,849	168,620	168,391	168,162	167,934	167,704	167,475	167,247	167,018	2,019,321
	a Recoverable Costs Allocated to Energy		169,536	169,307	169,078	168,849	168,620	168,391	168,162	167,934	167,704	167,475	167,247	167,018	2,019,321
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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)		163,495	163,350	163,488	163,630	163,354	163,236	162,864	162,521	162,321	161,818	161,316	161,163	1,952,556
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)		163,495	163,350	163,488	163,630	163,354	163,236	162,864	162,521	162,321	161,818	161,316	161,163	1,952,556

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) 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 2009 - December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: CEMS - Plants Crist, Scholz, Smith, & Daniel
P.E.s 1001, 1154, 1164, 1217, 1240, 1245, 1283, 1286, 1289, 1290, 1311, 1316, 1323, 1324, 1357, 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		360	5,068	62,641	556,604	1,553	6,730	250	18,250	250	252,666	103,404	0	
	b Clearings to Plant		360	5,068	62,641	556,604	1,553	6,730	250	18,250	250	65,000	0	291,070	
	c Retirements		0	125,636	110,727	0	0	0	0	0	0	59,148	0	0	
	d Cost of Removal		0	0	1,008	1	0	(1)	0	0	0	2,000	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	5,047,801	5,048,161	4,927,594	4,879,508	5,436,112	5,437,664	5,444,394	5,444,644	5,462,894	5,463,144	5,468,996	5,468,996	5,760,066	
3	Less: Accumulated Depreciation (C)	1,033,395	1,019,886	1,132,137	1,230,674	1,216,959	1,202,657	1,188,345	1,174,025	1,159,680	1,145,311	1,192,081	1,177,696	1,162,923	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	187,666	291,070	0	
5	Net Investment (Lines 2 + 3 + 4)	6,081,196	6,068,047	6,059,730	6,110,182	6,653,071	6,640,322	6,632,740	6,618,670	6,622,575	6,608,456	6,848,744	6,937,763	6,922,990	
6	Average Net Investment		6,074,622	6,063,889	6,084,956	6,381,626	6,646,696	6,636,531	6,625,705	6,620,622	6,615,515	6,728,600	6,893,253	6,930,376	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		44,630	44,551	44,706	46,886	48,833	48,759	48,679	48,642	48,604	49,435	50,645	50,917	575,287
	b Debt Component (Line 6 x Debt Component x 1/12)		12,678	12,655	12,699	13,318	13,872	13,850	13,828	13,817	13,807	14,043	14,386	14,464	163,417
8	Investment Expenses														
	a Depreciation (E)		13,377	13,253	13,065	13,584	14,170	14,179	14,188	14,213	14,237	14,246	14,253	14,641	167,406
	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		1,359	1,359	1,359	1,359	1,359	1,359	1,359	1,359	1,359	1,359	1,359	1,359	16,308
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		72,176	71,950	71,961	75,279	78,366	78,279	78,186	78,163	78,139	79,215	80,775	81,513	924,002
	a Recoverable Costs Allocated to Energy		72,176	71,950	71,961	75,279	78,366	78,279	78,186	78,163	78,139	79,215	80,775	81,513	924,002
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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)		69,604	69,418	69,582	72,952	75,919	75,883	75,723	75,643	75,631	76,539	77,911	78,656	893,461
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)		69,604	69,418	69,582	72,952	75,919	75,883	75,723	75,643	75,631	76,539	77,911	78,656	893,461

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist, $2,232,602; Scholz $916;802 Smith $1,317,122; Daniel $581,275. Ending Balances: Crist, $2,521,810; Scholz $916,802; Smith $1,740,179; Daniel $581,275.
(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 2009 - December 2009

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)	(201,338)	(203,174)	(205,010)	(206,846)	(208,682)	(210,518)	(212,354)	(214,190)	(216,026)	(217,862)	(219,698)	(221,534)	(223,370)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	716,686	714,850	713,014	711,178	709,342	707,506	705,670	703,834	701,998	700,162	698,326	696,490	694,654	
6	Average Net Investment		715,769	713,933	712,097	710,261	708,425	706,589	704,753	702,917	701,081	699,245	697,409	695,573	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		5,259	5,245	5,232	5,218	5,205	5,191	5,178	5,164	5,151	5,137	5,124	5,110	62,214
	b Debt Component (Line 6 x Debt Component x 1/12)		1,494	1,490	1,486	1,482	1,478	1,475	1,471	1,467	1,463	1,459	1,455	1,452	17,672
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	1,835	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)		8,588	8,571	8,553	8,536	8,519	8,501	8,484	8,468	8,450	8,433	8,415	8,399	101,917
	a Recoverable Costs Allocated to Energy		661	659	657	656	656	654	653	651	650	649	648	646	7,840
	b Recoverable Costs Allocated to Demand		7,927	7,912	7,896	7,880	7,863	7,847	7,831	7,817	7,800	7,784	7,767	7,753	94,077
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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)		637	636	635	636	636	634	632	630	629	627	625	623	7,580
13	Retail Demand-Related Recoverable Costs (I)		7,643	7,629	7,613	7,598	7,582	7,566	7,551	7,537	7,521	7,505	7,489	7,476	90,710
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		8,280	8,265	8,248	8,234	8,218	8,200	8,183	8,167	8,150	8,132	8,114	8,099	98,290

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 2009 - December 2009

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)	242,972	242,972	242,972	242,972	242,972	242,972	242,972	242,972	242,972	242,972	242,972	242,972	242,972	
3	Less: Accumulated Depreciation (C)	(63,696)	(64,290)	(64,884)	(65,478)	(66,072)	(66,666)	(67,260)	(67,854)	(68,448)	(69,042)	(69,636)	(70,230)	(70,823)	
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)	179,276	178,682	178,088	177,494	176,900	176,306	175,712	175,118	174,524	173,930	173,336	172,742	172,149	
6	Average Net Investment		178,979	178,385	177,791	177,197	176,603	176,009	175,415	174,821	174,227	173,633	173,039	172,446	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,315	1,310	1,306	1,302	1,298	1,293	1,289	1,285	1,280	1,276	1,271	1,267	15,492
	b Debt Component (Line 6 x Debt Component x 1/12)		373	372	371	370	369	367	366	365	363	363	361	360	4,400
8	Investment Expenses														
	a Depreciation (E)		594	594	594	594	594	594	594	594	594	594	594	593	7,127
	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)		2,282	2,276	2,271	2,266	2,261	2,254	2,249	2,244	2,237	2,233	2,226	2,220	27,019
	a Recoverable Costs Allocated to Energy		175	175	175	175	174	173	173	172	172	172	172	171	2,079
	b Recoverable Costs Allocated to Demand		2,107	2,101	2,096	2,091	2,087	2,081	2,076	2,072	2,065	2,061	2,054	2,049	24,940
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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)		169	169	169	170	169	168	168	166	166	166	166	165	2,011
13	Retail Demand-Related Recoverable Costs (I)		2,032	2,026	2,021	2,016	2,012	2,007	2,002	1,998	1,991	1,987	1,980	1,976	24,048
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,201	2,195	2,190	2,186	2,181	2,175	2,170	2,164	2,157	2,153	2,146	2,141	26,059

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning and Ending Balances: Crist, $149,949; 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 2009 - December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Cooling Tower Cell
P.E. 1232
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	506,368	506,206	506,044	505,882	505,720	505,558	505,396	505,234	505,072	504,910	504,748	504,586	504,424	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	506,368	506,206	506,044	505,882	505,720	505,558	505,396	505,234	505,072	504,910	504,748	504,586	504,424	
6	Average Net Investment		506,287	506,125	505,963	505,801	505,639	505,477	505,315	505,153	504,991	504,829	504,667	504,505	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		3,720	3,719	3,717	3,716	3,715	3,714	3,713	3,711	3,710	3,709	3,708	3,707	44,559
	b Debt Component (Line 6 x Debt Component x 1/12)		1,057	1,056	1,056	1,056	1,055	1,055	1,055	1,054	1,054	1,054	1,053	1,053	12,658
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)		4,939	4,937	4,935	4,934	4,932	4,931	4,930	4,927	4,926	4,925	4,923	4,922	59,161
	a Recoverable Costs Allocated to Energy		380	380	380	380	379	379	379	379	379	379	379	379	4,552
	b Recoverable Costs Allocated to Demand		4,559	4,557	4,555	4,554	4,553	4,552	4,551	4,548	4,547	4,546	4,544	4,543	54,609
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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)		366	367	367	368	367	367	367	367	367	366	366	366	4,401
13	Retail Demand-Related Recoverable Costs (I)		4,396	4,394	4,392	4,391	4,390	4,389	4,388	4,385	4,384	4,383	4,381	4,380	52,653
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		4,762	4,761	4,759	4,759	4,757	4,756	4,755	4,752	4,751	4,749	4,747	4,746	57,054

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 2009 - December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 1-5 Dechlorination
P.E. 1248
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	
3	Less: Accumulated Depreciation (C)	(145,859)	(146,673)	(147,487)	(148,301)	(149,115)	(149,929)	(150,743)	(151,557)	(152,371)	(153,185)	(153,999)	(154,813)	(155,627)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	159,464	158,650	157,836	157,022	156,208	155,394	154,580	153,766	152,952	152,138	151,324	150,510	149,696	
6	Average Net Investment		159,057	158,243	157,429	156,615	155,801	154,987	154,173	153,359	152,545	151,731	150,917	150,103	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,169	1,163	1,157	1,151	1,145	1,139	1,133	1,127	1,121	1,115	1,109	1,103	13,632
	b Debt Component (Line 6 x Debt Component x 1/12)		332	330	329	327	325	323	322	320	318	317	315	313	3,871
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)		2,315	2,307	2,300	2,292	2,284	2,276	2,269	2,261	2,253	2,246	2,238	2,230	27,271
	a Recoverable Costs Allocated to Energy		178	177	177	176	176	175	175	174	173	173	172	172	2,098
	b Recoverable Costs Allocated to Demand		2,137	2,130	2,123	2,116	2,108	2,101	2,094	2,087	2,080	2,073	2,066	2,058	25,173
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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)		172	171	171	171	171	170	169	168	167	167	166	166	2,029
13	Retail Demand-Related Recoverable Costs (I)		2,061	2,054	2,047	2,040	2,033	2,026	2,019	2,012	2,006	1,999	1,992	1,984	24,273
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,233	2,225	2,218	2,211	2,204	2,196	2,188	2,180	2,173	2,166	2,158	2,150	26,302

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 2009 - December 2009

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)	(26,624)	(26,808)	(26,992)	(27,176)	(27,360)	(27,544)	(27,728)	(27,912)	(28,096)	(28,280)	(28,464)	(28,648)	(28,832)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	42,299	42,115	41,931	41,747	41,563	41,379	41,195	41,011	40,827	40,643	40,459	40,275	40,091	
6	Average Net Investment		42,207	42,023	41,839	41,655	41,471	41,287	41,103	40,919	40,735	40,551	40,367	40,183	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		310	309	307	306	305	303	302	301	299	298	297	295	3,632
	b Debt Component (Line 6 x Debt Component x 1/12)		88	88	87	87	87	86	86	85	85	85	84	84	1,032
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)		582	581	578	577	576	573	572	570	568	567	565	563	6,872
	a Recoverable Costs Allocated to Energy		45	45	44	44	44	44	44	44	44	44	43	43	528
	b Recoverable Costs Allocated to Demand		537	536	534	533	532	529	528	526	524	523	522	520	6,344
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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)		43	43	43	43	43	43	43	43	43	43	41	41	512
13	Retail Demand-Related Recoverable Costs (I)		518	517	515	514	513	510	509	507	505	504	503	501	6,116
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		561	560	558	557	556	553	552	550	548	547	544	542	6,628

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 2009 - December 2009

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)	(48,419)	(48,690)	(48,961)	(49,232)	(49,503)	(49,774)	(50,045)	(50,316)	(50,587)	(50,858)	(51,129)	(51,400)	(51,671)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	53,076	52,805	52,534	52,263	51,992	51,721	51,450	51,179	50,908	50,637	50,366	50,095	49,824	
6	Average Net Investment		52,941	52,670	52,399	52,128	51,857	51,586	51,315	51,044	50,773	50,502	50,231	49,960	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		389	387	385	383	381	379	377	375	373	371	369	367	4,536
	b Debt Component (Line 6 x Debt Component x 1/12)		110	110	109	109	108	108	107	107	106	105	105	104	1,288
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)		770	768	765	763	760	758	755	753	750	747	745	742	9,076
	a Recoverable Costs Allocated to Energy		59	59	59	59	58	58	58	58	58	57	57	57	697
	b Recoverable Costs Allocated to Demand		711	709	706	704	702	700	697	695	692	690	688	685	8,379
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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)		57	57	57	57	56	56	56	56	56	55	55	55	673
13	Retail Demand-Related Recoverable Costs (I)		686	684	681	679	677	675	672	670	667	665	663	660	8,079
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		743	741	738	736	733	731	728	726	723	720	718	715	8,752

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 2009 - December 2009

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)	(28,724)	(28,883)	(29,042)	(29,201)	(29,360)	(29,519)	(29,678)	(29,837)	(29,996)	(30,155)	(30,314)	(30,473)	(30,632)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	30,819	30,660	30,501	30,342	30,183	30,024	29,865	29,706	29,547	29,388	29,229	29,070	28,911	
6	Average Net Investment		30,740	30,581	30,422	30,263	30,104	29,945	29,786	29,627	29,468	29,309	29,150	28,991	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		226	225	224	222	221	220	219	218	217	215	214	213	2,634
	b Debt Component (Line 6 x Debt Component x 1/12)		64	64	63	63	63	62	62	62	61	61	61	61	747
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)		449	448	446	444	443	441	440	439	437	435	434	433	5,289
	a Recoverable Costs Allocated to Energy		35	34	34	34	34	34	34	34	34	33	33	33	406
	b Recoverable Costs Allocated to Demand		414	414	412	410	409	407	406	405	403	402	401	400	4,883
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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)		34	33	33	33	33	33	33	33	33	32	32	32	394
13	Retail Demand-Related Recoverable Costs (I)		399	399	397	395	394	392	391	391	389	388	387	386	4,708
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		433	432	430	428	427	425	424	424	422	420	419	418	5,102

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 2009 - December 2009

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)	(59,991)	(60,972)	(61,953)	(62,934)	(63,915)	(64,896)	(65,877)	(66,858)	(67,839)	(68,820)	(69,801)	(70,782)	(71,763)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	331,128	330,147	329,166	328,185	327,204	326,223	325,242	324,261	323,280	322,299	321,318	320,337	319,356	
6	Average Net Investment		330,638	329,657	328,676	327,695	326,714	325,733	324,752	323,771	322,790	321,809	320,828	319,847	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,429	2,422	2,415	2,408	2,400	2,393	2,386	2,379	2,372	2,364	2,357	2,350	28,675
	b Debt Component (Line 6 x Debt Component x 1/12)		690	688	686	684	682	680	678	676	674	672	670	668	8,148
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)		4,100	4,091	4,082	4,073	4,063	4,054	4,045	4,036	4,027	4,017	4,008	3,999	48,595
	a Recoverable Costs Allocated to Energy		4,100	4,091	4,082	4,073	4,063	4,054	4,045	4,036	4,027	4,017	4,008	3,999	48,595
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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)		3,954	3,947	3,947	3,947	3,936	3,930	3,918	3,906	3,898	3,881	3,866	3,859	46,989
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)		3,954	3,947	3,947	3,947	3,936	3,930	3,918	3,906	3,898	3,881	3,866	3,859	46,989

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 2009 - December 2009

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)	(1,143,071)	(1,148,867)	(1,154,663)	(1,160,459)	(1,166,255)	(1,172,051)	(1,177,847)	(1,183,643)	(1,189,439)	(1,195,235)	(1,201,031)	(1,206,827)	(1,212,623)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	1,639,529	1,633,733	1,627,937	1,622,141	1,616,345	1,610,549	1,604,753	1,598,957	1,593,161	1,587,365	1,581,569	1,575,773	1,569,977	
6	Average Net Investment		1,636,631	1,630,835	1,625,039	1,619,243	1,613,447	1,607,651	1,601,855	1,596,059	1,590,263	1,584,467	1,578,671	1,572,875	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		12,024	11,982	11,939	11,897	11,854	11,811	11,769	11,726	11,684	11,641	11,598	11,556	141,481
	b Debt Component (Line 6 x Debt Component x 1/12)		3,416	3,404	3,391	3,379	3,367	3,355	3,343	3,331	3,319	3,307	3,295	3,283	40,190
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)		21,236	21,182	21,126	21,072	21,017	20,962	20,908	20,853	20,799	20,744	20,689	20,635	251,223
	a Recoverable Costs Allocated to Energy		1,634	1,629	1,625	1,621	1,617	1,612	1,608	1,604	1,600	1,596	1,591	1,587	19,324
	b Recoverable Costs Allocated to Demand		19,602	19,553	19,501	19,451	19,400	19,350	19,300	19,249	19,199	19,148	19,098	19,048	231,899
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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)		1,576	1,572	1,571	1,571	1,567	1,563	1,557	1,552	1,549	1,542	1,535	1,531	18,686
13	Retail Demand-Related Recoverable Costs (I)		18,901	18,853	18,803	18,755	18,706	18,658	18,609	18,560	18,512	18,463	18,415	18,366	223,601
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		20,477	20,425	20,374	20,326	20,273	20,221	20,166	20,112	20,061	20,005	19,950	19,897	242,287

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 2009 - December 2009

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)	100,003	99,630	99,257	98,884	98,511	98,138	97,765	97,392	97,019	96,646	96,273	95,900	95,527	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	278,965	278,592	278,219	277,846	277,473	277,100	276,727	276,354	275,981	275,608	275,235	274,862	274,489	
6	Average Net Investment		278,779	278,406	278,033	277,660	277,287	276,914	276,541	276,168	275,795	275,422	275,049	274,676	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,048	2,045	2,043	2,040	2,037	2,034	2,032	2,029	2,026	2,024	2,020	2,018	24,396
	b Debt Component (Line 6 x Debt Component x 1/12)		581	581	580	579	579	578	577	577	575	574	574	573	6,928
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)		3,002	2,999	2,996	2,992	2,989	2,985	2,982	2,979	2,974	2,971	2,967	2,964	35,800
	a Recoverable Costs Allocated to Energy		231	231	230	230	230	230	229	229	229	229	229	228	2,755
	b Recoverable Costs Allocated to Demand		2,771	2,768	2,766	2,762	2,759	2,755	2,753	2,750	2,745	2,742	2,738	2,736	33,045
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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)		223	223	222	223	223	223	222	222	222	221	221	220	2,665
13	Retail Demand-Related Recoverable Costs (I)		2,672	2,669	2,667	2,663	2,660	2,656	2,654	2,652	2,647	2,644	2,640	2,638	31,862
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,895	2,892	2,889	2,886	2,883	2,879	2,876	2,874	2,869	2,865	2,861	2,858	34,527

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) 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 2009 - December 2009

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		0	0	2,900	(2,900)	0	(2,900)	0	2,900	0	0	0	0	
b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
c	Retirements		0	0	0	970	11,058	0	0	0	0	0	0	0	
d	Cost of Removal		7,538	5,450	233,811	286,751	176,570	453,091	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)	16,204,251	16,204,251	16,204,251	16,204,251	16,203,281	16,192,224	16,192,224	16,192,224	16,192,224	16,192,224	16,192,224	16,192,224	16,192,224	
3	Less: Accumulated Depreciation (C)	(6,500,495)	(6,545,124)	(6,591,841)	(6,410,197)	(6,174,643)	(6,039,166)	(5,638,211)	(5,690,347)	(5,742,483)	(5,794,619)	(5,846,755)	(5,898,891)	(5,951,027)	
4	CWIP - Non Interest Bearing	0	0	0	2,900	0	0	(2,900)	(2,900)	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	9,703,756	9,659,127	9,612,410	9,796,954	10,028,639	10,153,058	10,551,113	10,498,977	10,449,741	10,397,605	10,345,469	10,293,333	10,241,197	
6	Average Net Investment		9,681,441	9,635,768	9,704,682	9,912,796	10,090,848	10,352,085	10,525,045	10,474,359	10,423,673	10,371,537	10,319,401	10,267,265	
7	Return on Average Net Investment														
a	Equity Component (Line 6 x Equity Component x 1/12) (D)		71,130	70,794	71,300	72,829	74,137	76,057	77,328	76,955	76,583	76,200	75,817	75,434	894,564
b	Debt Component (Line 6 x Debt Component x 1/12)		20,205	20,110	20,254	20,688	21,060	21,605	21,966	21,860	21,754	21,645	21,537	21,428	254,112
8	Investment Expenses														
a	Depreciation (E)		41,855	41,855	41,855	41,854	41,839	41,824	41,824	41,824	41,824	41,824	41,824	41,824	502,026
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		27,270	27,270	27,270	27,270	27,270	27,270	27,270	27,270	27,270	27,270	27,270	27,270	327,240
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		170,772	170,341	170,991	172,953	174,618	177,068	178,700	178,221	177,743	177,251	176,760	176,268	2,101,686
a	Recoverable Costs Allocated to Energy		13,136	13,103	13,153	13,304	13,432	13,621	13,746	13,709	13,673	13,635	13,597	13,559	161,668
b	Recoverable Costs Allocated to Demand		157,636	157,238	157,838	159,649	161,186	163,447	164,954	164,512	164,070	163,616	163,163	162,709	1,940,018
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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)		12,668	12,642	12,718	12,893	13,013	13,204	13,313	13,267	13,234	13,174	13,115	13,084	156,325
13	Retail Demand-Related Recoverable Costs (I)		151,995	151,611	152,190	153,936	155,418	157,598	159,051	158,625	158,199	157,761	157,324	156,887	1,870,595
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		164,663	164,253	164,908	166,829	168,431	170,802	172,364	171,892	171,433	170,935	170,439	169,971	2,026,920

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 2009 - December 2009

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)	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	
3	Less: Accumulated Depreciation (C)	(18,567)	(18,847)	(19,127)	(19,407)	(19,687)	(19,967)	(20,247)	(20,527)	(20,807)	(21,087)	(21,367)	(21,647)	(21,927)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	115,566	115,286	115,006	114,726	114,446	114,166	113,886	113,606	113,326	113,046	112,766	112,486	112,206	
6	Average Net Investment		115,426	115,146	114,866	114,586	114,306	114,026	113,746	113,466	113,186	112,906	112,626	112,346	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		848	846	844	842	839	838	836	833	831	830	827	825	10,039
	b Debt Component (Line 6 x Debt Component x 1/12)		241	240	240	239	239	238	237	237	237	235	235	234	2,852
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)		1,369	1,366	1,364	1,361	1,358	1,356	1,353	1,350	1,348	1,345	1,342	1,339	16,251
	a Recoverable Costs Allocated to Energy		106	106	104	104	104	104	104	104	104	104	103	103	1,250
	b Recoverable Costs Allocated to Demand		1,263	1,260	1,260	1,257	1,254	1,252	1,249	1,246	1,244	1,241	1,239	1,236	15,001
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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)		102	102	101	101	101	101	101	101	101	100	99	99	1,209
13	Retail Demand-Related Recoverable Costs (I)		1,218	1,215	1,215	1,212	1,209	1,207	1,204	1,201	1,199	1,197	1,195	1,192	14,464
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,320	1,317	1,316	1,313	1,310	1,308	1,305	1,302	1,300	1,297	1,294	1,291	15,673

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 2009 - December 2009

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		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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 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 2009 - December 2009

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		0	382,521	198,107	(123,127)	145,955	1,457	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	1,554,232	1,457	(3)	0	0	0	0	0	
	c Retirements		0	0	0	0	1,195,516	123,904	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	61,933	17,537	31,647	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)	134,444,847	134,444,847	134,444,847	134,444,847	134,444,847	134,803,563	134,681,116	134,681,113	134,681,113	134,681,113	134,681,113	134,681,113	134,681,113	
3	Less: Accumulated Depreciation (C)	(17,511,485)	(17,900,508)	(18,289,531)	(18,678,554)	(19,005,644)	(18,182,093)	(18,416,359)	(18,806,012)	(19,195,665)	(19,585,318)	(19,974,971)	(20,364,624)	(20,754,277)	
4	CWIP - Non Interest Bearing	950,774	950,774	1,333,295	1,531,402	1,408,275	(3)	(3)	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	117,884,136	117,495,113	117,488,611	117,297,694	116,847,477	116,621,467	116,264,754	115,875,101	115,485,448	115,095,795	114,706,142	114,316,489	113,926,836	
6	Average Net Investment		117,689,624	117,491,862	117,393,153	117,072,586	116,734,472	116,443,111	116,069,927	115,680,274	115,290,621	114,900,968	114,511,315	114,121,662	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		864,666	863,213	862,488	860,133	857,648	855,507	852,765	849,903	847,040	844,177	841,315	838,451	10,237,306
	b Debt Component (Line 6 x Debt Component x 1/12)		245,618	245,206	245,000	244,331	243,624	243,016	242,237	241,425	240,611	239,799	238,985	238,172	2,908,024
8	Investment Expenses														
	a Depreciation (E)		358,051	358,051	358,051	358,051	358,530	358,845	358,681	358,681	358,681	358,681	358,681	358,681	4,301,665
	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)		1,499,307	1,497,442	1,496,511	1,493,487	1,490,774	1,488,340	1,484,655	1,480,981	1,477,304	1,473,629	1,469,953	1,466,276	17,818,659
	a Recoverable Costs Allocated to Energy		1,499,307	1,497,442	1,496,511	1,493,487	1,490,774	1,488,340	1,484,655	1,480,981	1,477,304	1,473,629	1,469,953	1,466,276	17,818,659
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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)		1,445,884	1,444,751	1,447,030	1,447,320	1,444,222	1,442,775	1,437,883	1,433,243	1,429,886	1,423,856	1,417,827	1,414,876	17,229,553
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)		1,445,884	1,444,751	1,447,030	1,447,320	1,444,222	1,442,775	1,437,883	1,433,243	1,429,886	1,423,856	1,417,827	1,414,876	17,229,553

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 2009 - December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: SPCC Compliance
P.E. 1272 & 1404
(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	9,873	(133)	25	61	0	0	0	0	7,587	7,587	
	b Clearings to Plant		0	0	0	0	0	0	9,826	0	0	0	0	15,174	
	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)	919,836	919,836	919,836	919,836	919,836	919,836	919,836	929,662	929,662	929,662	929,662	929,662	944,836	
3	Less: Accumulated Depreciation (C)	(60,068)	(62,521)	(64,974)	(67,427)	(69,880)	(72,333)	(74,786)	(77,249)	(79,722)	(82,195)	(84,668)	(87,141)	(89,630)	
4	CWIP - Non Interest Bearing	0	0	0	9,873	9,740	9,765	9,826	0	0	0	0	7,587	0	
5	Net Investment (Lines 2 + 3 + 4)	859,768	857,315	854,862	862,282	859,696	857,268	854,876	852,413	849,940	847,467	844,994	850,108	855,206	
6	Average Net Investment		858,542	856,089	858,572	860,989	858,482	856,072	853,644	851,176	848,703	846,230	847,551	852,657	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		6,308	6,290	6,308	6,326	6,307	6,290	6,272	6,254	6,235	6,217	6,227	6,264	75,298
	b Debt Component (Line 6 x Debt Component x 1/12)		1,792	1,787	1,792	1,797	1,792	1,787	1,782	1,776	1,771	1,766	1,769	1,779	21,390
8	Investment Expenses														
	a Depreciation (E)		2,453	2,453	2,453	2,453	2,453	2,453	2,463	2,473	2,473	2,473	2,473	2,489	29,562
	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)		10,553	10,530	10,553	10,576	10,552	10,530	10,517	10,503	10,479	10,456	10,469	10,532	126,250
	a Recoverable Costs Allocated to Energy		812	810	812	814	812	810	809	808	806	804	805	810	9,712
	b Recoverable Costs Allocated to Demand		9,741	9,720	9,741	9,762	9,740	9,720	9,708	9,695	9,673	9,652	9,664	9,722	116,538
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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)		783	781	785	789	787	785	784	782	780	777	776	782	9,391
13	Retail Demand-Related Recoverable Costs (I)		9,392	9,372	9,392	9,413	9,391	9,372	9,361	9,348	9,327	9,307	9,318	9,374	112,367
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		10,175	10,153	10,177	10,202	10,178	10,157	10,145	10,130	10,107	10,084	10,094	10,156	121,758

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist, $919,836; Smith $0. Ending Balances: Crist, $919,836; Smith $25,000.
(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) 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 2009 - December 2009

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)	(9,907)	(10,075)	(10,243)	(10,411)	(10,579)	(10,747)	(10,915)	(11,083)	(11,251)	(11,419)	(11,587)	(11,755)	(11,923)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	52,963	52,795	52,627	52,459	52,291	52,123	51,955	51,787	51,619	51,451	51,283	51,115	50,947	
6	Average Net Investment		52,879	52,711	52,543	52,375	52,207	52,039	51,871	51,703	51,535	51,367	51,199	51,031	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		389	387	386	385	384	382	381	380	379	377	376	375	4,581
	b Debt Component (Line 6 x Debt Component x 1/12)		110	110	110	109	109	109	108	108	108	107	107	107	1,302
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)		667	665	664	662	661	659	657	656	655	652	651	650	7,899
	a Recoverable Costs Allocated to Energy		667	665	664	662	661	659	657	656	655	652	651	650	7,899
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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)		643	642	642	642	640	639	636	635	634	630	628	627	7,638
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)		643	642	642	642	640	639	636	635	634	630	628	627	7,638

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 2009 - December 2009

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		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	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)	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	
3	Less: Accumulated Depreciation (C)	(1,447,293)	(1,517,803)	(1,588,313)	(1,658,823)	(1,729,333)	(1,799,843)	(1,870,353)	(1,940,863)	(2,011,373)	(2,081,883)	(2,152,393)	(2,222,903)	(2,293,413)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	28,392,385	28,321,875	28,251,365	28,180,855	28,110,345	28,039,835	27,969,325	27,898,815	27,828,305	27,757,795	27,687,285	27,616,775	27,546,265	
6	Average Net Investment		28,357,130	28,286,620	28,216,110	28,145,600	28,075,090	28,004,580	27,934,070	27,863,560	27,793,050	27,722,540	27,652,030	27,581,520	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		208,340	207,822	207,304	206,786	206,268	205,750	205,232	204,714	204,196	203,678	203,159	202,641	2,465,890
	b Debt Component (Line 6 x Debt Component x 1/12)		59,181	59,034	58,887	58,740	58,593	58,446	58,298	58,151	58,004	57,857	57,710	57,563	700,464
8	Investment Expenses														
	a Depreciation (E)		70,510	70,510	70,510	70,510	70,510	70,510	70,510	70,510	70,510	70,510	70,510	70,510	846,120
	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)		338,031	337,366	336,701	336,036	335,371	334,706	334,040	333,375	332,710	332,045	331,379	330,714	4,012,474
	a Recoverable Costs Allocated to Energy		338,031	337,366	336,701	336,036	335,371	334,706	334,040	333,375	332,710	332,045	331,379	330,714	4,012,474
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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)		325,986	325,495	325,568	325,648	324,898	324,459	323,516	322,629	322,031	320,830	319,628	319,121	3,879,809
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)		325,986	325,495	325,568	325,648	324,898	324,459	323,516	322,629	322,031	320,830	319,628	319,121	3,879,809

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist $13,997,697; Smith $15,715,200; Scholz $126,781. Ending Balances: Crist, $13,997,697; Smith $15,715,200; Scholz $126,781.
(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

Schedule 8E
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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2009 - December 2009

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		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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 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 2009 - December 2009

Return on Capital Investments, Depreciation and Taxes
For Project: Plant Crist Water Conservation Project
P.E.'s 1227 & 1298
(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	7,801,485	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	7,801,485	
	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	7,895,220	
3	Less: Accumulated Depreciation (C)	(6,148)	(6,398)	(6,648)	(6,898)	(7,148)	(7,398)	(7,648)	(7,898)	(8,148)	(8,398)	(8,648)	(8,898)	(19,551)	
4	CWIP - Non Interest Bearing (J)	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	87,587	87,337	87,087	86,837	86,587	86,337	86,087	85,837	85,587	85,337	85,087	84,837	7,875,669	
6	Average Net Investment		87,462	87,212	86,962	86,712	86,462	86,212	85,962	85,712	85,462	85,212	84,962	3,980,253	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		643	641	639	637	635	633	632	630	628	626	624	29,243	36,211
	b Debt Component (Line 6 x Debt Component x 1/12)		183	182	181	181	180	180	179	179	178	178	177	8,307	10,285
8	Investment Expenses														
	a Depreciation (E)		250	250	250	250	250	250	250	250	250	250	250	10,653	13,403
	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)		1,076	1,073	1,070	1,068	1,065	1,063	1,061	1,059	1,056	1,054	1,051	48,203	59,899
	a Recoverable Costs Allocated to Energy		83	83	82	82	82	82	82	81	81	81	81	3,708	4,608
	b Recoverable Costs Allocated to Demand		993	990	988	986	983	981	979	978	975	973	970	44,495	55,291
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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)		80	80	79	79	79	79	79	78	78	78	78	3,578	4,445
13	Retail Demand-Related Recoverable Costs (I)		957	955	953	951	948	946	944	943	940	938	935	42,903	53,313
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,037	1,035	1,032	1,030	1,027	1,025	1,023	1,021	1,018	1,016	1,013	46,481	57,758

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
(J) Revised to exclude $73,956 that was incorrectly included in CWIP in December 2008 for PE 1298.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2009 - December 2009

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	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		6,863	(6,609)	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		6,863	(6,609)	0	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)	5,969,022	5,975,885	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	
3	Less: Accumulated Depreciation (C)	(498,352)	(514,280)	(530,208)	(546,128)	(562,048)	(577,968)	(593,888)	(609,808)	(625,728)	(641,648)	(657,568)	(673,488)	(689,408)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	5,470,670	5,461,605	5,439,067	5,423,147	5,407,227	5,391,307	5,375,387	5,359,467	5,343,547	5,327,627	5,311,707	5,295,787	5,279,867	
6	Average Net Investment		5,466,137	5,450,336	5,431,107	5,415,187	5,399,267	5,383,347	5,367,427	5,351,507	5,335,587	5,319,667	5,303,747	5,287,827	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		40,160	40,044	39,902	39,785	39,668	39,551	39,434	39,318	39,201	39,084	38,967	38,850	473,964
	b Debt Component (Line 6 x Debt Component x 1/12)		11,408	11,375	11,335	11,301	11,268	11,235	11,202	11,169	11,135	11,102	11,069	11,036	134,635
8	Investment Expenses														
	a Depreciation (E)		15,928	15,928	15,920	15,920	15,920	15,920	15,920	15,920	15,920	15,920	15,920	15,920	191,056
	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)		67,496	67,347	67,157	67,006	66,856	66,706	66,556	66,407	66,256	66,106	65,956	65,806	799,655
	a Recoverable Costs Allocated to Energy		5,192	5,181	5,166	5,154	5,143	5,131	5,120	5,108	5,097	5,085	5,074	5,062	61,513
	b Recoverable Costs Allocated to Demand		62,304	62,166	61,991	61,852	61,713	61,575	61,436	61,299	61,159	61,021	60,882	60,744	738,142
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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)		5,007	4,999	4,995	4,995	4,982	4,974	4,959	4,943	4,933	4,913	4,894	4,885	59,479
13	Retail Demand-Related Recoverable Costs (I)		60,075	59,941	59,773	59,639	59,505	59,372	59,238	59,105	58,970	58,837	58,703	58,570	711,728
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		65,082	64,940	64,768	64,634	64,487	64,346	64,197	64,048	63,903	63,750	63,597	63,455	771,207

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 2009 - December 2009

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, 1810, 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		(200,921)	304,752	746,338	6,277,341	651,419	4,143,400	506,611	284,708	181,552	180,786	874,325	531,810,585	
	b Clearings to Plant		(323,013)	509,938	411,583	6,151,203	3,391,482	4,580,167	496,075	274,881	175,599	175,599	865,778	530,616,435	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	60,689,270	60,366,257	60,876,195	61,287,778	67,438,981	70,830,463	75,410,629	75,906,704	76,181,585	76,357,184	76,532,783	77,398,561	608,014,996	
3	Less: Accumulated Depreciation (C)	(1,870,105)	(2,026,578)	(2,183,302)	(2,341,116)	(2,507,769)	(2,686,364)	(2,872,353)	(3,062,736)	(3,254,107)	(3,446,078)	(3,638,517)	(3,832,345)	(4,734,904)	
4	CWIP - Non Interest Bearing	4,529,518	4,651,611	4,446,425	4,781,180	4,907,319	2,167,256	1,730,489	1,741,025	1,750,852	1,756,805	1,761,992	1,770,539	2,964,689	
5	Net Investment (Lines 2 + 3 + 4)	63,348,683	62,991,289	63,139,318	63,727,842	69,838,530	70,311,355	74,268,766	74,584,994	74,678,331	74,667,912	74,656,259	75,336,756	606,244,781	
6	Average Net Investment		63,169,986	63,065,304	63,433,580	66,783,186	70,074,942	72,290,060	74,426,880	74,631,662	74,673,121	74,662,085	74,996,507	340,790,769	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		464,110	463,341	466,047	490,656	514,841	531,115	546,814	548,319	548,623	548,542	550,999	2,503,790	8,177,197
	b Debt Component (Line 6 x Debt Component x 1/12)		131,836	131,617	132,386	139,377	146,246	150,869	155,329	155,756	155,843	155,820	156,518	711,230	2,322,827
8	Investment Expenses														
	a Depreciation (E)		156,015	156,266	157,356	166,195	178,137	185,531	189,925	190,913	191,513	191,981	193,370	902,101	2,859,303
	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		9,164	9,164	9,164	9,164	9,164	9,164	9,164	9,164	9,164	9,164	9,164	9,164	109,968
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		761,583	760,846	765,411	805,850	848,846	877,137	901,690	904,610	905,601	905,965	910,509	4,126,743	13,474,791
	a Recoverable Costs Allocated to Energy		761,583	760,846	765,411	805,850	848,846	877,137	901,690	904,610	905,601	905,965	910,509	4,126,743	13,474,791
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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)		734,446	734,074	740,103	780,939	822,339	850,284	873,283	875,451	876,533	875,365	878,222	3,982,082	13,023,121
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)		734,446	734,074	740,103	780,939	822,339	850,284	873,283	875,451	876,533	875,365	878,222	3,982,082	13,023,121

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Beginning Balances: Crist $49,169,696; Smith $7,698,377; Daniel $3,264,866, Scholz $556,331. Ending Balances: Crist $592,369,378; Smith $11,389,634; Daniel $3,592,561, Scholz $663,423.
(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 2009 - December 2009

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	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	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)	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	
3	Less: Accumulated Depreciation (C)	(4,731)	(5,125)	(5,519)	(5,913)	(6,307)	(6,701)	(7,095)	(7,489)	(7,883)	(8,277)	(8,671)	(9,065)	(9,459)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	18,923	18,529	18,135	17,741	17,347	16,953	16,559	16,165	15,771	15,377	14,983	14,589	14,195	
6	Average Net Investment		18,726	18,332	17,938	17,544	17,150	16,756	16,362	15,968	15,574	15,180	14,786	14,392	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		138	135	132	129	126	123	120	117	114	112	109	106	1,461
	b Debt Component (Line 6 x Debt Component x 1/12)		39	38	37	37	36	35	34	33	33	32	31	30	415
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)		571	567	563	560	556	552	548	544	541	538	534	530	6,604
	a Recoverable Costs Allocated to Energy		44	44	43	43	43	42	42	42	42	41	41	41	508
	b Recoverable Costs Allocated to Demand		527	523	520	517	513	510	506	502	499	497	493	489	6,096
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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)		42	42	42	42	42	41	41	41	41	40	40	40	494
13	Retail Demand-Related Recoverable Costs (I)		508	504	501	498	495	492	488	484	481	479	475	472	5,877
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		550	546	543	540	537	533	529	525	522	519	515	512	6,371

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 2009 - December 2009

Return on Working Capital, Mercury Allowance Expenses
For Project: Mercury Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	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	0	0	0	0	0	0	0	0	0	0	0	0
	c SO2 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		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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 Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

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

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2009 - December 2009

Return on Working Capital, Annual NOx Expenses
For Project: Annual Nox Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	7,016,000	5,002,500	587,500	1,623,500	4,025,000	2,037,500	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														
	a FERC 158.1 Allowance Inventory	0	0	7,016,000	11,444,399	10,996,347	11,249,597	13,938,655	13,808,885	11,441,268	9,248,326	7,380,055	5,416,850	3,315,044	
	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	7,016,000	11,444,399	10,996,347	11,249,597	13,938,655	13,808,885	11,441,268	9,248,326	7,380,055	5,416,850	3,315,044	
4	Average Net Working Capital Balance		0	3,508,000	9,230,199	11,220,373	11,122,972	12,594,126	13,873,770	12,625,077	10,344,797	8,314,191	6,398,452	4,365,947	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		0	25,773	67,814	82,436	81,720	92,529	101,931	92,756	76,003	61,084	47,009	32,077	761,132
	b Debt Component (Line 4 x Debt Component x 1/12)		0	7,321	19,263	23,417	23,214	26,284	28,955	26,349	21,590	17,352	13,354	9,112	216,211
6	Total Return Component (D)		0	33,094	87,077	105,853	104,934	118,813	130,886	119,105	97,593	78,436	60,363	41,189	977,343
7	Expenses														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c SO2 Allowance Expense		0	0	574,101	1,035,552	1,370,250	1,335,942	2,167,270	2,367,617	2,192,942	1,868,272	1,963,205	2,101,806	16,976,956
8	Net Expenses (E)		0	0	574,101	1,035,552	1,370,250	1,335,942	2,167,270	2,367,617	2,192,942	1,868,272	1,963,205	2,101,806	16,976,956
9	Total System Recoverable Expenses (Lines 6 + 8)		0	33,094	661,178	1,141,405	1,475,184	1,454,755	2,298,156	2,486,722	2,290,535	1,946,708	2,023,568	2,142,995	17,954,299
	a Recoverable Costs Allocated to Energy		0	33,094	661,178	1,141,405	1,475,184	1,454,755	2,298,156	2,486,722	2,290,535	1,946,708	2,023,568	2,142,995	17,954,299
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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	31,930	639,317	1,106,122	1,429,118	1,410,218	2,225,755	2,406,564	2,217,014	1,880,956	1,951,811	2,067,873	17,366,678
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)		0	31,930	639,317	1,106,122	1,429,118	1,410,218	2,225,755	2,406,564	2,217,014	1,880,956	1,951,811	2,067,873	17,366,678

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

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2009 - December 2009

Return on Working Capital, Seasonal NOx Expenses
For Project: Seasonal Nox Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	1,022,000	10,000	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														
	a FERC 158.1 Allowance Inventory	0	0	0	1,022,000	1,032,000	849,952	688,713	476,395	264,077	67,424	67,424	67,424	67,424	
	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	1,022,000	1,032,000	849,952	688,713	476,395	264,077	67,424	67,424	67,424	67,424	
4	Average Net Working Capital Balance		0	0	511,000	1,027,000	940,976	769,333	582,554	370,236	165,751	67,424	67,424	67,424	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		0	0	3,754	7,545	6,913	5,652	4,280	2,720	1,218	495	495	495	33,567
	b Debt Component (Line 4 x Debt Component x 1/12)		0	0	1,066	2,143	1,964	1,606	1,216	773	346	141	141	141	9,537
6	Total Return Component (D)		0	0	4,820	9,688	8,877	7,258	5,496	3,493	1,564	636	636	636	43,104
7	Expenses														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c SO2 Allowance Expense		0	0	0	0	182,048	161,239	212,318	212,318	196,654	0	0	0	964,576
8	Net Expenses (E)		0	0	0	0	182,048	161,239	212,318	212,318	196,654	0	0	0	964,576
9	Total System Recoverable Expenses (Lines 6 + 8)		0	0	4,820	9,688	190,925	168,497	217,814	215,811	198,218	636	636	636	1,007,680
	a Recoverable Costs Allocated to Energy		0	0	4,820	9,688	190,925	168,497	217,814	215,811	198,218	636	636	636	1,007,680
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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	4,661	9,389	184,963	163,339	210,952	208,854	191,855	615	613	614	975,855
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)		0	0	4,661	9,389	184,963	163,339	210,952	208,854	191,855	615	613	614	975,855

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 8E
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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2009 - December 2009

Return on Working Capital, SO2 Expenses
For Project: SO2 Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
a	Purchases/Transfers		0	0	0	0	0	8,832,000	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	48,693	0	(5,825)	0	0	0	0	0	0	
2	Working Capital														
a	FERC 158.1 Allowance Inventory	7,911,392	7,719,950	7,608,588	7,437,171	7,245,362	6,907,350	15,444,589	14,588,006	13,724,407	12,909,917	12,434,666	11,919,698	11,211,121	
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	(1,054,181)	(1,048,089)	(1,041,997)	(1,035,905)	(1,073,567)	(1,062,534)	(1,046,509)	(1,036,309)	(1,026,109)	(1,015,909)	(1,005,709)	(995,509)	(985,309)	
3	Total Working Capital Balance	6,857,211	6,671,861	6,566,591	6,401,265	6,171,795	5,844,815	14,398,080	13,551,696	12,698,297	11,894,008	11,428,957	10,924,188	10,225,812	
4	Average Net Working Capital Balance		6,764,536	6,619,226	6,483,928	6,286,530	6,008,305	10,121,447	13,974,888	13,124,997	12,296,152	11,661,482	11,176,572	10,575,000	
5	Return on Average Net Working Capital Balance														
a	Equity Component (Line 4 x Equity Component x 1/12) (A)		49,699	48,631	47,637	46,187	44,143	74,362	102,674	96,429	90,340	85,677	82,114	77,695	845,588
b	Debt Component (Line 4 x Debt Component x 1/12)		14,118	13,814	13,532	13,120	12,539	21,123	29,166	27,392	25,662	24,338	23,326	22,070	240,200
6	Total Return Component (D)		63,817	62,445	61,169	59,307	56,682	95,485	131,840	123,821	116,002	110,015	105,440	99,765	1,085,788
7	Expenses														
a	Gains		(6,092)	(6,092)	(6,092)	(11,032)	(11,032)	(10,200)	(10,200)	(10,200)	(10,200)	(10,200)	(10,200)	(10,200)	(111,739)
b	Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
c	SO2 Allowance Expense		191,441	111,362	171,418	191,809	338,012	294,760	856,583	863,599	814,490	475,251	514,968	708,577	5,532,271
8	Net Expenses (E)		185,350	105,270	165,326	180,777	326,980	284,560	846,383	853,399	804,290	465,051	504,768	698,377	5,420,531
9	Total System Recoverable Expenses (Lines 6 + 8)		249,167	167,715	226,495	240,084	383,662	380,045	978,223	977,220	920,292	575,066	610,208	798,142	6,506,319
a	Recoverable Costs Allocated to Energy		249,167	167,715	226,495	240,084	383,662	380,045	978,223	977,220	920,292	575,066	610,208	798,142	6,506,319
b	Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9636933	0.9641378	0.9662595	0.9684099	0.9680953	0.9687071	0.9678187	0.9670888	0.9672252	0.9655484	0.9638645	0.9642705	
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)		240,288	161,814	219,006	232,662	371,681	368,410	947,406	945,720	890,752	555,643	588,570	770,163	6,292,115
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)		240,288	161,814	219,006	232,662	371,681	368,410	947,406	945,720	890,752	555,643	588,570	770,163	6,292,115

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

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 090007-EI

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

Richard W Dodd

Richard W. Dodd
Supervisor of Rates and Regulatory Matters

Sworn to and subscribed before me
this 31st day of July, 2009.

Linda C. Webb

Notary Public, State of Florida at Large

(SEAL)

LINDA C. WEBB
Notary Public-State of Florida
Comm. Exp. May 31, 2010
Comm. No. DD 541216

Schedule 1P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to be Recovered

For the Projected Period
January 2010 - December 2010

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)	36,127,453	2,705,858	38,833,311
	b Projected Capital Projects (Schedule 3P, Lines 7, 8 & 9)	112,204,438	4,901,216	117,105,654
	c Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b)	148,331,891	7,607,074	155,938,965
2	True-Up for Estimated Over/(Under) Recovery for the period January 2009 - December 2009 (Schedule 1E, Line 3)	374,499	30,628	405,127
3	Final True-Up for the period January 2008 - December 2008 (Schedule 1A, Line 3)	1,227,936	153,475	1,381,411
4	Total Jurisdictional Amount to be Recovered/(Refunded) in the projection period January 2010 - December 2010 (Line 1c - Line 2 - Line 3)	146,729,456	7,422,971	154,152,427
5	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier)	146,835,101	7,428,316	154,263,417

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.

Docket No. 090007-EI
2010 Projection Filing
Exhibit RWD-3, Page 1 of 88

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 090007-EI EXHIBIT 34
COMPANY Gulf Power Company (Direct)
WITNESS R. W. Dodd (RWD-3)
DATE 11/02/09

Gulf Power Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2010 - December 2010

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	786,000	6,000	0	0	0	0	0	0	0	124,374	0	916,374	0	916,374
	.3 Title V	8,885	8,885	9,820	9,458	9,158	10,858	13,719	12,458	9,908	9,658	9,158	14,469	126,436	0	126,436
	.4 Asbestos Fees	0	0	500	700	300	0	0	300	400	200	0	200	2,600	2,600	0
	.5 Emission Monitoring	58,133	38,133	43,932	39,030	63,030	43,330	48,800	49,030	45,330	39,030	39,030	53,108	559,914	0	559,914
	.6 General Water Quality	23,540	23,740	45,760	36,860	24,534	49,034	34,429	34,034	46,034	30,784	30,534	62,425	441,707	441,707	0
	.7 Groundwater Contamination Investigation	71,928	72,660	76,454	82,841	87,841	414,641	111,957	87,841	408,641	83,841	63,841	67,961	1,630,452	1,630,452	0
	.8 State NPDES Administration	0	7,500	0	0	0	0	0	0	0	0	0	34,500	42,000	42,000	0
	.9 Lead and Copper Rule	5,250	0	0	5,250	0	0	5,250	0	0	5,250	0	0	21,000	21,000	0
	.10 Env Auditing/Assessment	500	0	500	0	5,000	3,000	0	2,000	0	500	500	0	12,000	12,000	0
	.11 General Solid & Hazardous Waste	32,126	33,183	35,974	43,854	45,283	44,846	53,590	53,949	56,513	50,681	44,682	63,453	558,133	558,133	0
	.12 Above Ground Storage Tanks	978	978	10,494	994	1,494	10,494	4,240	4,494	41,494	5,494	4,994	12,240	98,387	98,387	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	24,499	15,999	24,499	15,999	24,499	15,999	24,499	15,999	24,499	15,999	24,499	16,000	242,989	0	242,989
	.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	218,089	211,596	224,800	232,122	225,629	225,629	279,030	227,859	219,225	159,955	186,757	236,811	2,647,500	0	2,647,500
	.20 CAIR/CAMR/CAVR Compliance Program	1,691,638	1,739,638	1,692,972	1,692,973	1,708,366	1,708,366	1,753,617	1,694,519	1,695,791	1,695,792	1,796,992	1,858,941	20,729,607	0	20,729,607
	.21 MACT ICR	13,525	13,525	27,050	64,920	81,150	108,200	129,840	75,740	27,050	0	0	0	541,000	0	541,000
	.22 Mercury Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.23 Annual NOx Allowances	2,200,537	157,270	201,251	299,594	341,674	549,130	824,904	851,254	767,080	782,451	707,061	731,215	8,413,422	0	8,413,422
	.24 Seasonal NOx Allowances	0	0	0	0	13,757	14,944	82,480	167,328	150,913	0	0	0	429,422	0	429,422
	.25 SO_2 Allowances	334,032	215,996	165,504	169,006	194,491	229,254	250,008	260,078	237,223	243,440	228,991	235,559	2,763,581	0	2,763,581
2	Total of O & M Activities	4,683,661	3,325,103	2,565,509	2,693,601	2,826,206	3,427,725	3,616,363	3,536,883	3,730,101	3,123,076	3,261,413	3,386,883	40,176,524	2,806,278	37,370,246
3	Recoverable Costs Allocated to Energy	4,549,338	3,187,042	2,395,827	2,523,102	2,661,754	2,905,710	3,406,897	3,354,266	3,177,019	2,946,326	3,116,862	3,146,103	37,370,246		
4	Recoverable Costs Allocated to Demand	134,322	138,061	169,682	170,499	164,452	522,015	209,467	182,618	553,082	176,750	144,551	240,780	2,806,278		
5	Retail Energy Jurisdictional Factor	0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030			
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)	4,391,792	3,079,160	2,314,230	2,442,573	2,576,902	2,812,956	3,298,502	3,246,005	3,074,436	2,846,770	3,008,206	3,035,921	36,127,453		
8	Jurisdictional Demand Recoverable Costs (B)	129,516	133,121	163,610	164,398	158,567	503,335	201,971	176,083	533,290	170,425	139,378	232,164	2,705,858		
9	Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8)	4,521,308	3,212,281	2,477,840	2,606,971	2,735,469	3,316,291	3,500,473	3,422,088	3,607,726	3,017,195	3,147,584	3,268,085	38,833,311		

Notes:
(A) Line 3 x Line 5 x 1.0007 line loss multiplier
(B) Line 4 x Line 6

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 - December 2010

Capital Investment Projects - Recoverable Costs
(in Dollars)

Line		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	End of Period Total	Method of Classification Demand	Method of Classification Energy
1	Description of Investment Projects (A)															
	.1 Air Quality Assurance Testing	3,405	3,379	3,355	3,330	3,305	3,280	3,256	3,232	3,206	3,182	3,157	3,133	39,220	0	39,220
	.2 Crist 5, 6 & 7 Precipitator Projects	154,245	155,188	155,657	156,129	156,362	156,363	156,360	156,358	156,160	156,594	157,063	157,770	1,874,449	0	1,874,449
	.3 Crist 7 Flue Gas Conditioning	14,022	14,020	14,018	14,017	14,014	14,013	14,010	14,009	14,006	14,005	14,003	14,001	168,138	0	168,138
	.4 Low NOx Burners, Crist 6 & 7	166,788	166,560	166,332	166,101	165,873	165,643	165,416	165,188	164,956	164,729	164,499	164,272	1,986,357	0	1,986,357
	.5 CEMs- Plants Crist, Scholz, Smith, and Daniel	81,710	79,264	76,831	76,730	76,628	76,536	76,435	76,338	76,235	76,137	76,038	75,938	924,820	0	924,820
	.6 Sub. Contam. Mobile Groundwater Treat. Sys.	8,380	8,363	8,346	8,329	8,311	8,294	8,277	8,258	8,242	8,224	8,209	8,190	99,423	91,774	7,649
	.7 Raw Water Well Flowmeters - Plants Crist & Smith	2,215	2,209	2,204	2,198	2,193	2,187	2,181	2,177	2,170	2,166	2,160	2,154	26,214	24,198	2,016
	.8 Crist Cooling Tower Cell	4,920	4,918	4,917	4,916	4,914	4,912	4,911	4,909	4,908	4,907	4,905	4,903	58,940	54,407	4,533
	.9 Crist 1-5 Dechlorination	2,223	2,215	2,207	2,199	2,192	2,184	2,176	2,169	2,161	2,153	2,146	2,138	26,163	24,151	2,012
	.10 Crist Diesel Fuel Oil Remediation	561	560	558	556	554	553	551	549	547	546	544	542	6,621	6,111	510
	.11 Crist Bulk Tanker Unload Sec Contain Struc	740	737	735	732	729	727	724	722	719	717	714	711	8,707	8,036	671
	.12 Crist IWW Sampling System	431	430	428	426	425	424	422	421	419	417	416	415	5,074	4,684	390
	.13 Sodium Injection System	3,990	3,979	3,971	3,961	3,951	3,944	3,933	3,926	3,915	3,906	3,897	3,887	47,260	0	47,260
	.14 Smith Stormwater Collection System	20,579	20,525	20,470	20,416	20,361	20,306	20,252	20,197	20,143	20,088	20,033	19,978	243,348	224,629	18,719
	.15 Smith Waste Water Treatment Facility	2,961	2,957	2,954	2,951	2,947	2,944	2,938	2,936	2,933	2,928	2,926	2,922	35,297	32,581	2,716
	.16 Daniel Ash Management Project	177,286	176,795	176,303	175,812	175,320	174,827	174,335	173,843	173,352	172,861	172,368	171,876	2,094,978	1,933,825	161,153
	.17 Smith Water Conservation	1,927	3,101	4,274	5,451	6,629	7,803	8,980	10,155	11,332	12,508	13,684	14,865	100,709	92,964	7,745
	.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	1,462,601	1,458,926	1,455,249	1,451,573	1,447,897	1,444,219	1,440,545	1,436,870	1,433,193	1,429,517	1,425,840	1,422,164	17,308,594	0	17,308,594
	.20 SPCC Compliance	10,561	10,538	10,514	10,491	10,466	10,443	10,420	10,396	10,372	10,348	10,325	10,302	125,176	115,547	9,629
	.21 Crist Common FTIR Monitor	648	646	644	643	642	640	638	637	635	634	632	630	7,669	0	7,669
	.22 Precipitator Upgrades for CAM Compliance	330,049	329,384	328,719	328,052	327,388	326,723	326,060	325,392	324,726	324,063	323,397	322,732	3,916,685	0	3,916,685
	.23 Plant Groundwater Investigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.24 Crist Water Conservation	99,088	105,918	110,514	113,651	116,325	158,248	198,924	198,508	198,089	197,672	197,254	196,836	1,891,027	1,745,562	145,465
	.25 Plant NPDES Permit Compliance Projects	65,654	65,506	65,355	65,205	65,054	64,903	64,754	64,604	64,513	64,480	64,449	64,461	778,958	719,039	59,919
	.26 CAIR/CAMR/CAVR Compliance Program	7,356,729	7,366,291	7,368,291	7,364,268	7,353,339	7,346,054	7,337,668	7,322,976	7,307,493	7,292,009	7,276,525	7,261,513	87,953,156	0	87,953,156
	.27 General Water Quality	526	522	519	515	511	507	503	500	497	493	489	485	6,067	5,601	466
	.28 Mercury Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.29 Annual Nox Allowances	23,229	18,393	27,374	31,733	36,208	49,719	53,449	45,543	37,909	30,600	23,574	16,790	394,521	0	394,521
	.30 Seasonal Nox Allowances	636	636	636	636	571	1,291	2,539	2,213	731	0	0	0	9,869	0	9,869
	.31 SO2 Allowances	94,895	92,300	90,501	88,923	87,208	85,209	82,949	80,543	78,197	75,929	73,701	71,509	1,001,864	0	1,001,864
2	Total Investment Projects - Recoverable Costs	10,090,999	10,094,260	10,101,876	10,099,944	10,090,317	10,132,896	10,163,606	10,133,569	10,101,939	10,071,813	10,042,948	10,015,137	121,139,304	5,083,109	116,056,195
3	Recoverable Costs Allocated to Energy	9,723,565	9,720,142	9,723,141	9,717,930	9,705,460	9,708,961	9,701,745	9,671,714	9,640,031	9,609,805	9,580,837	9,552,864	116,056,195		
4	Recoverable Costs Allocated to Demand	367,434	374,118	378,735	382,014	384,857	423,935	461,861	461,855	461,908	462,008	462,111	462,273	5,083,109		
5	Retail Energy Jurisdictional Factor	0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030			
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)	9,386,832	9,391,116	9,391,988	9,407,767	9,396,069	9,399,039	9,393,071	9,359,555	9,328,762	9,285,092	9,246,843	9,218,304	112,204,438		
8	Jurisdictional Demand Recoverable Costs (C)	354,286	360,331	365,182	368,344	371,085	408,765	445,334	445,328	445,379	445,476	445,575	445,731	4,901,216		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	9,741,118	9,751,847	9,757,170	9,776,111	9,767,154	9,807,804	9,838,405	9,804,883	9,774,141	9,730,568	9,692,418	9,664,035	117,105,654		

Notes:

(A) Each project's Total System Recoverable Expenses is 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 2010 - December 2010

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)	(136,158)	(138,781)	(141,404)	(144,027)	(146,650)	(149,273)	(151,896)	(154,519)	(157,142)	(159,765)	(162,388)	(165,011)	(167,634)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	84,136	81,513	78,890	76,267	73,644	71,021	68,398	65,775	63,152	60,529	57,906	55,283	52,660	
6	Average Net Investment		82,825	80,202	77,579	74,956	72,333	69,710	67,087	64,464	61,841	59,218	56,595	53,972	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		609	589	570	551	531	512	493	474	454	435	416	397	6,031
	b Debt Component (Line 6 x Debt Component x 1/12)		173	167	162	156	151	145	140	135	129	124	118	113	1,713
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)		3,405	3,379	3,355	3,330	3,305	3,280	3,256	3,232	3,206	3,182	3,157	3,133	39,220
	a Recoverable Costs Allocated to Energy		3,405	3,379	3,355	3,330	3,305	3,280	3,256	3,232	3,206	3,182	3,157	3,133	39,220
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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)		3,287	3,265	3,241	3,224	3,200	3,175	3,152	3,128	3,102	3,074	3,047	3,023	37,918
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)		3,287	3,265	3,241	3,224	3,200	3,175	3,152	3,128	3,102	3,074	3,047	3,023	37,918

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 amortization; 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 2010 - December 2010

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		200,000	100,000	100,000	100,000	50,000	50,000	50,000	50,000	50,000	100,000	100,000	150,000	
	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 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)	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	14,531,879	
3	Less: Accumulated Depreciation (C)	(3,570,817)	(3,620,949)	(3,671,081)	(3,721,213)	(3,771,345)	(3,821,477)	(3,871,609)	(3,921,741)	(3,971,873)	(4,022,005)	(4,072,137)	(4,122,269)	(4,172,401)	
4	CWIP - Non Interest Bearing	0	200,000	300,000	400,000	500,000	550,000	600,000	650,000	700,000	750,000	850,000	950,000	1,100,000	
5	Net Investment (Lines 2 + 3 + 4)	10,961,062	11,110,930	11,160,798	11,210,666	11,260,534	11,260,402	11,260,270	11,260,138	11,260,006	11,259,874	11,309,742	11,359,610	11,459,478	
6	Average Net Investment		11,035,996	11,135,864	11,185,732	11,235,600	11,260,468	11,260,336	11,260,204	11,260,072	11,259,940	11,284,808	11,334,676	11,409,544	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		81,081	81,815	82,181	82,548	82,729	82,730	82,728	82,727	82,728	82,910	83,276	83,826	991,279
	b Debt Component (Line 6 x Debt Component x 1/12)		23,032	23,241	23,344	23,449	23,501	23,501	23,500	23,499	23,500	23,552	23,655	23,812	281,586
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)		154,245	155,188	155,657	156,129	156,362	156,363	156,360	156,358	156,360	156,594	157,063	157,770	1,874,449
	a Recoverable Costs Allocated to Energy		154,245	155,188	155,657	156,129	156,362	156,363	156,360	156,358	156,360	156,594	157,063	157,770	1,874,449
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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)		148,904	149,934	150,355	151,147	151,378	151,373	151,386	151,311	151,311	151,303	151,588	152,245	1,812,235
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)		148,904	149,934	150,355	151,147	151,378	151,373	151,386	151,311	151,311	151,303	151,588	152,245	1,812,235

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 2010 - December 2010

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)	1,464,825	1,464,621	1,464,417	1,464,213	1,464,009	1,463,805	1,463,601	1,463,397	1,463,193	1,462,989	1,462,785	1,462,581	1,462,377	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	1,464,825	1,464,621	1,464,417	1,464,213	1,464,009	1,463,805	1,463,601	1,463,397	1,463,193	1,462,989	1,462,785	1,462,581	1,462,377	
6	Average Net Investment		1,464,723	1,464,519	1,464,315	1,464,111	1,463,907	1,463,703	1,463,499	1,463,295	1,463,091	1,462,887	1,462,683	1,462,479	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		10,761	10,760	10,758	10,757	10,755	10,754	10,752	10,751	10,749	10,748	10,746	10,745	129,036
	b Debt Component (Line 6 x Debt Component x 1/12)		3,057	3,056	3,056	3,056	3,055	3,055	3,054	3,054	3,053	3,053	3,053	3,052	36,654
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)		14,022	14,020	14,018	14,017	14,014	14,013	14,010	14,009	14,006	14,005	14,003	14,001	168,138
	a Recoverable Costs Allocated to Energy		14,022	14,020	14,018	14,017	14,014	14,013	14,010	14,009	14,006	14,005	14,003	14,001	168,138
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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)		13,536	13,545	13,541	13,570	13,567	13,566	13,564	13,557	13,554	13,532	13,515	13,511	162,558
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)		13,536	13,545	13,541	13,570	13,567	13,566	13,564	13,557	13,554	13,532	13,515	13,511	162,558

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 2010 - December 2010

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)	6,021,777	5,997,513	5,973,249	5,948,985	5,924,721	5,900,457	5,876,193	5,851,929	5,827,665	5,803,401	5,779,137	5,754,873	5,730,609	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	15,119,700	15,095,436	15,071,172	15,046,908	15,022,644	14,998,380	14,974,116	14,949,852	14,925,588	14,901,324	14,877,060	14,852,796	14,828,532	
6	Average Net Investment		15,107,568	15,083,304	15,059,040	15,034,776	15,010,512	14,986,248	14,961,984	14,937,720	14,913,456	14,889,192	14,864,928	14,840,664	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		110,995	110,817	110,639	110,460	110,282	110,104	109,926	109,748	109,568	109,391	109,212	109,035	1,320,177
	b Debt Component (Line 6 x Debt Component x 1/12)		31,529	31,479	31,429	31,377	31,327	31,275	31,226	31,176	31,124	31,074	31,023	30,973	375,012
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)		166,788	166,560	166,332	166,101	165,873	165,643	165,416	165,188	164,956	164,729	164,499	164,272	1,986,357
	a Recoverable Costs Allocated to Energy		166,788	166,560	166,332	166,101	165,873	165,643	165,416	165,188	164,956	164,729	164,499	164,272	1,986,357
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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)		161,012	160,922	160,667	160,800	160,585	160,355	160,153	159,857	159,629	159,163	158,765	158,519	1,920,427
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)		161,012	160,922	160,667	160,800	160,585	160,355	160,153	159,857	159,629	159,163	158,765	158,519	1,920,427

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 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: CEMs- Plants Crist, Scholz, Smith, and Daniel
P.E.s 1001, 1154, 1164, 1217, 1240, 1245, 1283, 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		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	1,738,270	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)	5,760,066	5,760,066	4,021,796	4,021,796	4,021,796	4,021,796	4,021,796	4,021,796	4,021,796	4,021,796	4,021,796	4,021,796	4,021,796	
3	Less: Accumulated Depreciation (C)	1,162,923	1,147,762	2,873,187	2,862,661	2,852,135	2,841,609	2,831,083	2,820,557	2,810,031	2,799,505	2,788,979	2,778,453	2,767,927	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	6,922,989	6,907,828	6,894,983	6,884,457	6,873,931	6,863,405	6,852,879	6,842,353	6,831,827	6,821,301	6,810,775	6,800,249	6,789,723	
6	Average Net Investment		6,915,409	6,901,406	6,889,720	6,879,194	6,868,668	6,858,142	6,847,616	6,837,090	6,826,564	6,816,038	6,805,512	6,794,986	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		50,808	50,706	50,617	50,540	50,461	50,387	50,308	50,234	50,154	50,076	50,000	49,922	604,213
	b Debt Component (Line 6 x Debt Component x 1/12)		14,432	14,404	14,379	14,355	14,332	14,314	14,292	14,269	14,246	14,226	14,203	14,181	171,633
8	Investment Expenses														
	a Depreciation (E)		15,029	12,713	10,394	10,394	10,394	10,394	10,394	10,394	10,394	10,394	10,394	10,394	131,682
	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		1,309	1,309	1,309	1,309	1,309	1,309	1,309	1,309	1,309	1,309	1,309	1,309	15,708
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		81,710	79,264	76,831	76,730	76,628	76,536	76,435	76,338	76,235	76,137	76,038	75,938	924,820
	a Recoverable Costs Allocated to Energy		81,710	79,264	76,831	76,730	76,628	76,536	76,435	76,338	76,235	76,137	76,038	75,938	924,820
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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)		77,890	75,590	73,225	73,293	73,199	73,105	73,016	72,887	72,788	72,583	72,409	72,300	882,285
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)		77,890	75,590	73,225	73,293	73,199	73,105	73,016	72,887	72,788	72,583	72,409	72,300	882,285

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist, $2,521,809; Scholz $916,802; Smith $1,740,179; Daniel $581,275. Ending Balances: Crist, $783,539; Scholz $916,802; Smith $1,740,179; Daniel $581,275.
(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 2010 - December 2010

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)	(223,370)	(225,206)	(227,042)	(228,878)	(230,714)	(232,550)	(234,386)	(236,222)	(238,058)	(239,894)	(241,730)	(243,566)	(245,402)	
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)	694,654	692,818	690,982	689,146	687,310	685,474	683,638	681,802	679,966	678,130	676,294	674,458	672,622	
6	Average Net Investment		693,736	691,900	690,064	688,228	686,392	684,556	682,720	680,884	679,048	677,212	675,376	673,540	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		5,097	5,083	5,070	5,056	5,043	5,029	5,016	5,002	4,989	4,975	4,963	4,949	60,272
	b Debt Component (Line 6 x Debt Component x 1/12)		1,447	1,444	1,440	1,437	1,432	1,429	1,425	1,420	1,417	1,413	1,410	1,405	17,119
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)		8,380	8,363	8,346	8,329	8,311	8,294	8,277	8,258	8,242	8,224	8,209	8,190	99,423
	a Recoverable Costs Allocated to Energy		644	643	642	641	640	637	637	636	634	633	632	630	7,649
	b Recoverable Costs Allocated to Demand		7,736	7,720	7,704	7,688	7,671	7,657	7,640	7,622	7,608	7,591	7,577	7,560	91,774
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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)		622	622	620	621	620	617	617	616	614	612	610	608	7,399
13	Retail Demand-Related Recoverable Costs (I)		7,459	7,443	7,429	7,413	7,396	7,383	7,367	7,350	7,336	7,319	7,305	7,289	88,489
14	Total Juris. Recoverable Costs (Lines 12 + 13)		8,081	8,065	8,049	8,034	8,016	8,000	7,984	7,966	7,950	7,931	7,915	7,897	95,888

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 Projected Period Amount
January 2010 - December 2010

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)	242,972	242,972	242,972	242,972	242,972	242,972	242,972	242,972	242,972	242,972	242,972	242,972	242,972	
3	Less: Accumulated Depreciation (C)	(70,824)	(71,418)	(72,012)	(72,606)	(73,200)	(73,794)	(74,388)	(74,982)	(75,576)	(76,170)	(76,764)	(77,358)	(77,952)	
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)	172,148	171,554	170,960	170,366	169,772	169,178	168,584	167,990	167,396	166,802	166,208	165,614	165,020	
6	Average Net Investment		171,851	171,257	170,663	170,069	169,475	168,881	168,287	167,693	167,099	166,505	165,911	165,317	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,262	1,258	1,254	1,249	1,245	1,240	1,236	1,233	1,228	1,224	1,219	1,215	14,863
	b Debt Component (Line 6 x Debt Component x 1/12)		359	357	356	355	354	353	351	350	348	348	347	345	4,223
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)		2,215	2,209	2,204	2,198	2,193	2,187	2,181	2,177	2,170	2,166	2,160	2,154	26,214
	a Recoverable Costs Allocated to Energy		170	170	169	169	169	168	168	168	167	166	166	166	2,016
	b Recoverable Costs Allocated to Demand		2,045	2,039	2,035	2,029	2,024	2,019	2,013	2,009	2,003	2,000	1,994	1,988	24,198
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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)		164	164	163	164	164	163	163	163	162	160	160	160	1,950
13	Retail Demand-Related Recoverable Costs (I)		1,972	1,966	1,962	1,956	1,952	1,947	1,941	1,937	1,931	1,928	1,922	1,916	23,330
14	Total Juris. Recoverable Costs (Lines 12 + 13)		2,136	2,130	2,125	2,120	2,116	2,110	2,104	2,100	2,093	2,088	2,082	2,076	25,280

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning and Ending Balances: Crist, $149,949 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 2010 - December 2010

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)	504,424	504,262	504,100	503,938	503,776	503,614	503,452	503,290	503,128	502,966	502,804	502,642	502,480	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	504,424	504,262	504,100	503,938	503,776	503,614	503,452	503,290	503,128	502,966	502,804	502,642	502,480	
6	Average Net Investment		504,343	504,181	504,019	503,857	503,695	503,533	503,371	503,209	503,047	502,885	502,723	502,561	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		3,705	3,704	3,703	3,702	3,701	3,699	3,698	3,697	3,696	3,695	3,694	3,692	44,386
	b Debt Component (Line 6 x Debt Component x 1/12)		1,053	1,052	1,052	1,052	1,051	1,051	1,051	1,050	1,050	1,050	1,049	1,049	12,610
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)		4,920	4,918	4,917	4,916	4,914	4,912	4,911	4,909	4,908	4,907	4,905	4,903	58,940
	a Recoverable Costs Allocated to Energy		378	378	378	378	378	378	378	378	378	377	377	377	4,533
	b Recoverable Costs Allocated to Demand		4,542	4,540	4,539	4,538	4,536	4,534	4,533	4,531	4,530	4,530	4,528	4,526	54,407
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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	365	365	366	366	366	366	366	366	364	364	364	4,383
13	Retail Demand-Related Recoverable Costs (I)		4,379	4,378	4,377	4,376	4,374	4,372	4,371	4,369	4,368	4,368	4,366	4,364	52,462
14	Total Juris. Recoverable Costs (Lines 12 + 13)		4,744	4,743	4,742	4,742	4,740	4,738	4,737	4,735	4,734	4,732	4,730	4,728	56,845

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 2010 - December 2010

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)	(155,627)	(156,441)	(157,255)	(158,069)	(158,883)	(159,697)	(160,511)	(161,325)	(162,139)	(162,953)	(163,767)	(164,581)	(165,395)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	149,696	148,882	148,068	147,254	146,440	145,626	144,812	143,998	143,184	142,370	141,556	140,742	139,928	
6	Average Net Investment		149,289	148,475	147,661	146,847	146,033	145,219	144,405	143,591	142,777	141,963	141,149	140,335	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,097	1,091	1,085	1,079	1,073	1,067	1,061	1,055	1,049	1,043	1,037	1,031	12,768
	b Debt Component (Line 6 x Debt Component x 1/12)		312	310	308	306	305	303	301	300	298	296	295	293	3,627
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)		2,223	2,215	2,207	2,199	2,192	2,184	2,176	2,169	2,161	2,153	2,146	2,138	26,163
	a Recoverable Costs Allocated to Energy		171	170	170	169	169	168	167	167	166	166	165	164	2,012
	b Recoverable Costs Allocated to Demand		2,052	2,045	2,037	2,030	2,023	2,016	2,009	2,002	1,995	1,987	1,981	1,974	24,151
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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)		165	164	164	164	164	163	162	162	161	160	159	158	1,946
13	Retail Demand-Related Recoverable Costs (I)		1,979	1,972	1,964	1,957	1,951	1,944	1,937	1,930	1,924	1,916	1,910	1,903	23,287
14	Total Juris. Recoverable Costs (Lines 12 + 13)		2,144	2,136	2,128	2,121	2,115	2,107	2,099	2,092	2,085	2,076	2,069	2,061	25,233

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 name (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 2010 - December 2010

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)	(28,832)	(29,016)	(29,200)	(29,384)	(29,568)	(29,752)	(29,936)	(30,120)	(30,304)	(30,488)	(30,672)	(30,856)	(31,040)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	40,091	39,907	39,723	39,539	39,355	39,171	38,987	38,803	38,619	38,435	38,251	38,067	37,883	
6	Average Net Investment		39,999	39,815	39,631	39,447	39,263	39,079	38,895	38,711	38,527	38,343	38,159	37,975	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		294	293	291	290	288	287	286	284	283	282	280	279	3,437
	b Debt Component (Line 6 x Debt Component x 1/12)		83	83	83	82	82	82	81	81	80	80	80	79	976
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)		561	560	558	556	554	553	551	549	547	546	544	542	6,621
	a Recoverable Costs Allocated to Energy		43	43	43	43	43	43	42	42	42	42	42	42	510
	b Recoverable Costs Allocated to Demand		518	517	515	513	511	510	509	507	505	504	502	500	6,111
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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)		42	42	42	42	42	42	41	41	41	41	41	41	498
13	Retail Demand-Related Recoverable Costs (I)		499	498	497	495	493	492	491	489	487	486	484	482	5,893
14	Total Juris. Recoverable Costs (Lines 12 + 13)		541	540	539	537	535	534	532	530	528	527	525	523	6,391

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 2010 - December 2010

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)	(51,671)	(51,942)	(52,213)	(52,484)	(52,755)	(53,026)	(53,297)	(53,568)	(53,839)	(54,110)	(54,381)	(54,652)	(54,923)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	49,824	49,553	49,282	49,011	48,740	48,469	48,198	47,927	47,656	47,385	47,114	46,843	46,572	
6	Average Net Investment		49,689	49,418	49,147	48,876	48,605	48,334	48,063	47,792	47,521	47,250	46,979	46,708	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D		365	363	361	359	357	355	353	351	349	347	345	343	4,248
	b Debt Component (Line 6 x Debt Component x 1/12)		104	103	103	102	101	101	100	100	99	99	98	97	1,207
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)		740	737	735	732	729	727	724	722	719	717	714	711	8,707
	a Recoverable Costs Allocated to Energy		57	57	57	56	56	56	56	56	55	55	55	55	671
	b Recoverable Costs Allocated to Demand		683	680	678	676	673	671	668	666	664	662	659	656	8,036
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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)		55	55	55	54	54	54	54	54	53	53	53	53	647
13	Retail Demand-Related Recoverable Costs (I)		659	656	654	652	649	647	644	642	640	638	635	633	7,749
14	Total Juris. Recoverable Costs (Lines 12 + 13)		714	711	709	706	703	701	698	696	693	691	688	686	8,396

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 2010 - December 2010

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)	(30,632)	(30,791)	(30,950)	(31,109)	(31,268)	(31,427)	(31,586)	(31,745)	(31,904)	(32,063)	(32,222)	(32,381)	(32,540)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	28,911	28,752	28,593	28,434	28,275	28,116	27,957	27,798	27,639	27,480	27,321	27,162	27,003	
6	Average Net Investment		28,832	28,673	28,514	28,355	28,196	28,037	27,878	27,719	27,560	27,401	27,242	27,083	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		212	211	209	208	207	206	205	204	202	201	200	199	2,464
	b Debt Component (Line 6 x Debt Component x 1/12)		60	60	60	59	59	59	58	58	58	57	57	57	702
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)		431	430	428	426	425	424	422	421	419	417	416	415	5,074
	a Recoverable Costs Allocated to Energy		33	33	33	33	33	33	32	32	32	32	32	32	390
	b Recoverable Costs Allocated to Demand		398	397	395	393	392	391	390	389	387	385	384	383	4,684
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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)		32	32	32	32	32	32	31	31	31	31	31	31	378
13	Retail Demand-Related Recoverable Costs (I)		384	383	381	379	378	377	376	375	373	371	370	369	4,516
14	Total Juris. Recoverable Costs (Lines 12 + 13)		416	415	413	411	410	409	407	406	404	402	401	400	4,894

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 2010 - December 2010

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)	(71,763)	(72,744)	(73,725)	(74,706)	(75,687)	(76,668)	(77,649)	(78,630)	(79,611)	(80,592)	(81,573)	(82,554)	(83,535)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	319,356	318,375	317,394	316,413	315,432	314,451	313,470	312,489	311,508	310,527	309,546	308,565	307,584	
6	Average Net Investment		318,866	317,885	316,904	315,923	314,942	313,961	312,980	311,999	311,018	310,037	309,056	308,075	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,343	2,335	2,329	2,321	2,313	2,307	2,299	2,293	2,285	2,278	2,271	2,263	27,637
	b Debt Component (Line 6 x Debt Component x 1/12)		666	663	661	659	657	656	653	652	649	647	645	643	7,851
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)		3,990	3,979	3,971	3,961	3,951	3,944	3,933	3,926	3,915	3,906	3,897	3,887	47,260
	a Recoverable Costs Allocated to Energy		3,990	3,979	3,971	3,961	3,951	3,944	3,933	3,926	3,915	3,906	3,897	3,887	47,260
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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)		3,851	3,844	3,836	3,834	3,825	3,818	3,808	3,799	3,789	3,774	3,761	3,751	45,690
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)		3,851	3,844	3,836	3,834	3,825	3,818	3,808	3,799	3,789	3,774	3,761	3,751	45,690

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 2010 - December 2010

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)	(1,212,623)	(1,218,419)	(1,224,215)	(1,230,011)	(1,235,807)	(1,241,603)	(1,247,399)	(1,253,195)	(1,258,991)	(1,264,787)	(1,270,583)	(1,276,379)	(1,282,175)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	1,569,977	1,564,181	1,558,385	1,552,589	1,546,793	1,540,997	1,535,201	1,529,405	1,523,609	1,517,813	1,512,017	1,506,221	1,500,425	
6	Average Net Investment		1,567,079	1,561,283	1,555,487	1,549,691	1,543,895	1,538,099	1,532,303	1,526,507	1,520,711	1,514,915	1,509,119	1,503,323	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		11,513	11,471	11,428	11,386	11,343	11,300	11,258	11,215	11,173	11,130	11,087	11,045	135,349
	b Debt Component (Line 6 x Debt Component x 1/12)		3,270	3,258	3,246	3,234	3,222	3,210	3,198	3,186	3,174	3,162	3,150	3,137	38,447
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)		20,579	20,525	20,470	20,416	20,361	20,306	20,252	20,197	20,143	20,088	20,033	19,978	243,348
	a Recoverable Costs Allocated to Energy		1,583	1,579	1,575	1,570	1,566	1,562	1,558	1,554	1,549	1,545	1,541	1,537	18,719
	b Recoverable Costs Allocated to Demand		18,996	18,946	18,895	18,846	18,795	18,744	18,694	18,643	18,594	18,543	18,492	18,441	224,629
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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)		1,528	1,526	1,521	1,520	1,516	1,512	1,508	1,504	1,499	1,493	1,487	1,483	18,097
13	Retail Demand-Related Recoverable Costs (I)		18,316	18,268	18,219	18,172	18,122	18,073	18,025	17,976	17,929	17,879	17,830	17,781	216,590
14	Total Juris. Recoverable Costs (Lines 12 + 13)		19,844	19,794	19,740	19,692	19,638	19,585	19,533	19,480	19,428	19,372	19,317	19,264	234,687

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 2010 - December 2010

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)	95,527	95,154	94,781	94,408	94,035	93,662	93,289	92,916	92,543	92,170	91,797	91,424	91,051	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	274,489	274,116	273,743	273,370	272,997	272,624	272,251	271,878	271,505	271,132	270,759	270,386	270,013	
6	Average Net Investment		274,303	273,930	273,557	273,184	272,811	272,438	272,065	271,692	271,319	270,946	270,573	270,200	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,016	2,012	2,010	2,008	2,004	2,002	1,998	1,996	1,994	1,990	1,988	1,985	24,003
	b Debt Component (Line 6 x Debt Component x 1/12)		572	572	571	570	570	569	567	567	566	565	565	564	6,818
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)		2,961	2,957	2,954	2,951	2,947	2,944	2,938	2,936	2,933	2,928	2,926	2,922	35,297
	a Recoverable Costs Allocated to Energy		228	228	228	227	227	227	226	225	225	225	225	225	2,716
	b Recoverable Costs Allocated to Demand		2,733	2,729	2,726	2,724	2,720	2,717	2,712	2,711	2,708	2,703	2,701	2,697	32,581
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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)		220	220	220	220	220	220	219	218	218	217	217	217	2,626
13	Retail Demand-Related Recoverable Costs (I)		2,635	2,631	2,628	2,626	2,622	2,620	2,615	2,614	2,611	2,606	2,604	2,600	31,412
14	Total Juris. Recoverable Costs (Lines 12 + 13)		2,855	2,851	2,848	2,846	2,842	2,840	2,834	2,832	2,829	2,823	2,821	2,817	34,038

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) 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 2010 - December 2010

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		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	16,192,224	16,192,224	16,192,224	16,192,224	16,192,224	16,192,224	16,192,224	16,192,224	16,192,224	16,192,224	16,192,224	16,192,224	16,192,224	
3	Less: Accumulated Depreciation (C)	(5,951,027)	(6,003,163)	(6,055,299)	(6,107,435)	(6,159,571)	(6,211,707)	(6,263,843)	(6,315,979)	(6,368,115)	(6,420,251)	(6,472,387)	(6,524,523)	(6,576,659)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	10,241,197	10,189,061	10,136,925	10,084,789	10,032,653	9,980,517	9,928,381	9,876,245	9,824,109	9,771,973	9,719,837	9,667,701	9,615,565	
6	Average Net Investment		10,215,129	10,162,993	10,110,857	10,058,721	10,006,585	9,954,449	9,902,313	9,850,177	9,798,041	9,745,905	9,693,769	9,641,633	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		75,050	74,667	74,284	73,902	73,519	73,135	72,752	72,369	71,986	71,604	71,220	70,837	875,325
	b Debt Component (Line 6 x Debt Component x 1/12)		21,319	21,211	21,102	20,993	20,884	20,775	20,666	20,557	20,449	20,340	20,231	20,122	248,649
8	Investment Expenses														
	a Depreciation (E)		41,824	41,824	41,824	41,824	41,824	41,824	41,824	41,824	41,824	41,824	41,824	41,824	501,888
	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		28,781	28,781	28,781	28,781	28,781	28,781	28,781	28,781	28,781	28,781	28,781	28,781	345,372
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		177,286	176,795	176,303	175,812	175,320	174,827	174,335	173,843	173,352	172,861	172,368	171,876	2,094,978
	a Recoverable Costs Allocated to Energy		13,638	13,599	13,562	13,524	13,487	13,448	13,410	13,373	13,334	13,297	13,259	13,222	161,153
	b Recoverable Costs Allocated to Demand		163,648	163,196	162,741	162,288	161,833	161,379	160,925	160,470	160,018	159,564	159,109	158,654	1,933,825
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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)		13,166	13,139	13,100	13,092	13,057	13,019	12,983	12,942	12,904	12,848	12,796	12,759	155,805
13	Retail Demand-Related Recoverable Costs (I)		157,792	157,356	156,917	156,480	156,042	155,604	155,167	154,728	154,292	153,854	153,415	152,977	1,864,624
14	Total Juris. Recoverable Costs (Lines 12 + 13)		170,958	170,495	170,017	169,572	169,099	168,623	168,150	167,670	167,196	166,702	166,211	165,736	2,030,429

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 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Water Conservation
P.E. 1601, 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		124,950	124,500	124,950	124,950	124,950	124,950	124,950	124,950	124,950	124,950	124,950	126,000	
	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 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)	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	134,133	
3	Less: Accumulated Depreciation (C)	(21,927)	(22,207)	(22,487)	(22,767)	(23,047)	(23,327)	(23,607)	(23,887)	(24,167)	(24,447)	(24,727)	(25,007)	(25,287)	
4	CWIP - Non Interest Bearing	0	124,950	249,450	374,400	499,350	624,300	749,250	874,200	999,150	1,124,100	1,249,050	1,374,000	1,500,000	
5	Net Investment (Lines 2 + 3 + 4)	112,206	236,876	361,096	485,766	610,436	735,106	859,776	984,446	1,109,116	1,233,786	1,358,456	1,483,126	1,608,846	
6	Average Net Investment		174,541	298,986	423,431	548,101	672,771	797,441	922,111	1,046,781	1,171,451	1,296,121	1,420,791	1,545,986	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,283	2,196	3,111	4,027	4,944	5,859	6,775	7,691	8,607	9,523	10,439	11,358	75,813
	b Debt Component (Line 6 x Debt Component x 1/12)		364	625	883	1,144	1,405	1,664	1,925	2,184	2,445	2,705	2,965	3,227	21,536
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)		1,927	3,101	4,274	5,451	6,629	7,803	8,980	10,155	11,332	12,508	13,684	14,865	100,709
	a Recoverable Costs Allocated to Energy		148	239	329	419	510	599	690	781	871	962	1,053	1,144	7,745
	b Recoverable Costs Allocated to Demand		1,779	2,862	3,945	5,032	6,119	7,204	8,290	9,374	10,461	11,546	12,631	13,721	92,964
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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)		143	231	318	406	494	580	668	756	843	930	1,017	1,104	7,490
13	Retail Demand-Related Recoverable Costs (I)		1,716	2,760	3,804	4,852	5,901	6,947	7,994	9,039	10,087	11,133	12,179	13,230	89,642
14	Total Juris. Recoverable Costs (Lines 12 + 13)		1,859	2,991	4,122	5,258	6,395	7,527	8,662	9,795	10,930	12,063	13,196	14,334	97,132

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 2010 - December 2010
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		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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 2010 - December 2010

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	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	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) (J)	134,681,113	134,681,113	134,681,113	134,681,113	134,681,113	134,681,113	134,681,113	134,681,113	134,681,113	134,681,113	134,681,113	134,681,113	134,681,113	
3	Less: Accumulated Depreciation (C)	(20,754,277)	(21,143,930)	(21,533,583)	(21,923,236)	(22,312,889)	(22,702,542)	(23,092,195)	(23,481,848)	(23,871,501)	(24,261,154)	(24,650,807)	(25,040,460)	(25,430,113)	
4	CWIP - Non Interest Bearing (J)	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	113,926,836	113,537,183	113,147,530	112,757,877	112,368,224	111,978,571	111,588,918	111,199,265	110,809,612	110,419,959	110,030,306	109,640,653	109,251,000	
6	Average Net Investment		113,732,009	113,342,356	112,952,703	112,563,050	112,173,397	111,783,744	111,394,091	111,004,438	110,614,785	110,225,132	109,835,479	109,445,826	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		835,589	832,727	829,864	827,001	824,139	821,274	818,412	815,550	812,687	809,824	806,961	804,098	9,838,126
	b Debt Component (Line 6 x Debt Component x 1/12)		237,359	236,546	235,732	234,919	234,105	233,292	232,480	231,667	230,853	230,040	229,226	228,413	2,794,632
8	Investment Expenses														
	a Depreciation (E)		358,681	358,681	358,681	358,681	358,681	358,681	358,681	358,681	358,681	358,681	358,681	358,681	4,304,172
	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)		1,462,601	1,458,926	1,455,249	1,451,573	1,447,897	1,444,219	1,440,545	1,436,870	1,433,193	1,429,517	1,425,840	1,422,164	17,308,594
	a Recoverable Costs Allocated to Energy		1,462,601	1,458,926	1,455,249	1,451,573	1,447,897	1,444,219	1,440,545	1,436,870	1,433,193	1,429,517	1,425,840	1,422,164	17,308,594
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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)		1,411,950	1,409,541	1,405,686	1,405,243	1,401,741	1,398,117	1,394,713	1,390,495	1,386,916	1,381,214	1,376,134	1,372,358	16,734,108
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)		1,411,950	1,409,541	1,405,686	1,405,243	1,401,741	1,398,117	1,394,713	1,390,495	1,386,916	1,381,214	1,376,134	1,372,358	16,734,108

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 Projected Period Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: SPCC Compliance
P.E.'s 1272 & 1404
(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)	944,836	944,836	944,836	944,836	944,836	944,836	944,836	944,836	944,836	944,836	944,836	944,836	944,836	
3	Less: Accumulated Depreciation (C)	(89,630)	(92,135)	(94,640)	(97,145)	(99,650)	(102,155)	(104,660)	(107,165)	(109,670)	(112,175)	(114,680)	(117,185)	(119,690)	
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)	855,206	852,701	850,196	847,691	845,186	842,681	840,176	837,671	835,166	832,661	830,156	827,651	825,146	
6	Average Net Investment		853,953	851,448	848,943	846,438	843,933	841,428	838,923	836,418	833,913	831,408	828,903	826,398	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		6,274	6,256	6,237	6,219	6,200	6,182	6,164	6,145	6,127	6,108	6,090	6,072	74,074
	b Debt Component (Line 6 x Debt Component x 1/12)		1,782	1,777	1,772	1,767	1,761	1,756	1,751	1,746	1,740	1,735	1,730	1,725	21,042
8	Investment Expenses														
	a Depreciation (E)		2,505	2,505	2,505	2,505	2,505	2,505	2,505	2,505	2,505	2,505	2,505	2,505	30,060
	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)		10,561	10,538	10,514	10,491	10,466	10,443	10,420	10,396	10,372	10,348	10,325	10,302	125,176
	a Recoverable Costs Allocated to Energy		812	811	809	807	805	803	802	800	798	796	794	792	9,629
	b Recoverable Costs Allocated to Demand		9,749	9,727	9,705	9,684	9,661	9,640	9,618	9,596	9,574	9,552	9,531	9,510	115,547
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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)		784	784	781	781	779	777	776	774	772	769	766	764	9,307
13	Retail Demand-Related Recoverable Costs (I)		9,400	9,379	9,358	9,337	9,315	9,295	9,274	9,253	9,231	9,210	9,190	9,170	111,412
14	Total Juris. Recoverable Costs (Lines 12 + 13)		10,184	10,163	10,139	10,118	10,094	10,072	10,050	10,027	10,003	9,979	9,956	9,934	120,719

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist $919,836; Smith $25,000. Ending Balances: Crist $919,836; Smith $25,000.
(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% 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 2010 - December 2010

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)	(11,923)	(12,091)	(12,259)	(12,427)	(12,595)	(12,763)	(12,931)	(13,099)	(13,267)	(13,435)	(13,603)	(13,771)	(13,939)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	50,947	50,779	50,611	50,443	50,275	50,107	49,939	49,771	49,603	49,435	49,267	49,099	48,931	
6	Average Net Investment		50,863	50,695	50,527	50,359	50,191	50,023	49,855	49,687	49,519	49,351	49,183	49,015	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		374	372	371	370	369	368	366	365	364	363	361	360	4,403
	b Debt Component (Line 6 x Debt Component x 1/12)		106	106	105	105	105	104	104	104	103	103	103	102	1,250
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)		648	646	644	643	642	640	638	637	635	634	632	630	7,669
	a Recoverable Costs Allocated to Energy		648	646	644	643	642	640	638	637	635	634	632	630	7,669
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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)		626	624	622	622	622	620	618	616	614	613	610	608	7,415
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)		626	624	622	622	622	620	618	616	614	613	610	608	7,415

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 2010 - December 2010
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		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	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) (J)	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	
3	Less: Accumulated Depreciation (C) (J)	(2,293,413)	(2,363,923)	(2,434,433)	(2,504,943)	(2,575,453)	(2,645,963)	(2,716,473)	(2,786,983)	(2,857,493)	(2,928,003)	(2,998,513)	(3,069,023)	(3,139,533)	
4	CWIP - Non Interest Bearing (J)	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4) (J)	27,546,265	27,475,755	27,405,245	27,334,735	27,264,225	27,193,715	27,123,205	27,052,695	26,982,185	26,911,675	26,841,165	26,770,655	26,700,145	
6	Average Net Investment		27,511,010	27,440,500	27,369,990	27,299,480	27,228,970	27,158,460	27,087,950	27,017,440	26,946,930	26,876,420	26,805,910	26,735,400	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		202,123	201,605	201,087	200,568	200,051	199,533	199,017	198,497	197,979	197,461	196,944	196,425	2,391,290
	b Debt Component (Line 6 x Debt Component x 1/12)		57,416	57,269	57,122	56,974	56,827	56,680	56,533	56,385	56,237	56,092	55,943	55,797	679,275
8	Investment Expenses														
	a Depreciation (E)		70,510	70,510	70,510	70,510	70,510	70,510	70,510	70,510	70,510	70,510	70,510	70,510	846,120
	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)		330,049	329,384	328,719	328,052	327,388	326,723	326,060	325,392	324,726	324,063	323,397	322,732	3,916,685
	a Recoverable Costs Allocated to Energy		330,049	329,384	328,719	328,052	327,388	326,723	326,060	325,392	324,726	324,063	323,397	322,732	3,916,685
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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)		318,619	318,234	317,523	317,582	316,952	316,294	315,686	314,890	314,241	313,113	312,123	311,429	3,786,686
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)		318,619	318,234	317,523	317,582	316,952	316,294	315,686	314,890	314,241	313,113	312,123	311,429	3,786,686

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist $13,997,697; Smith $15,715,200; Scholz $126,781. Ending Balances: Crist $13,997,697; Smith $15,715,200; Scholz $126,781.
(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 Projected Period Amount
January 2010 - December 2010

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		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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	
13	Retail Demand-Related Recoverable Costs (I)		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	

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

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2010 Projection Filing
Exhibit RWD-3, Page 26 of 68

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Plant Crist Water Conservation Project
P.E.'s 1227 & 1298
(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		633,848	530,343	266,758	290,569	191,322	6,784,914	0	0	0	0	0	0	
	b Clearings to Plant (J)		633,848	530,343	266,758	290,569	191,322	6,784,914	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)	7,895,220	8,529,068	9,059,411	9,326,169	9,616,738	9,808,060	16,592,974	16,592,974	16,592,974	16,592,974	16,592,974	16,592,974	16,592,974	
3	Less: Accumulated Depreciation (C)	(19,551)	(41,453)	(64,907)	(89,424)	(114,684)	(140,587)	(175,793)	(220,046)	(264,299)	(308,552)	(352,805)	(397,058)	(441,311)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	7,875,669	8,487,615	8,994,504	9,236,745	9,502,054	9,667,473	16,417,181	16,372,928	16,328,675	16,284,422	16,240,169	16,195,916	16,151,663	
6	Average Net Investment		8,181,642	8,741,059	9,115,624	9,369,399	9,584,763	13,042,327	16,395,054	16,350,801	16,306,548	16,262,295	16,218,042	16,173,789	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		60,111	64,221	66,973	68,837	70,419	95,822	120,455	120,130	119,804	119,479	119,154	118,828	1,144,233
	b Debt Component (Line 6 x Debt Component x 1/12)		17,075	18,243	19,024	19,554	20,003	27,220	34,216	34,125	34,032	33,940	33,847	33,755	325,034
8	Investment Expenses														
	a Depreciation (E)		21,902	23,454	24,517	25,260	25,903	35,206	44,253	44,253	44,253	44,253	44,253	44,253	421,760
	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)		99,088	105,918	110,514	113,651	116,325	158,248	198,924	198,508	198,089	197,672	197,254	196,836	1,891,027
	a Recoverable Costs Allocated to Energy		7,623	8,147	8,501	8,742	8,948	12,173	15,301	15,270	15,238	15,206	15,174	15,142	145,465
	b Recoverable Costs Allocated to Demand		91,465	97,771	102,013	104,909	107,377	146,075	183,623	183,238	182,851	182,466	182,080	181,694	1,745,562
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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)		7,359	7,871	8,211	8,463	8,662	11,784	14,814	14,777	14,746	14,692	14,645	14,611	140,635
13	Retail Demand-Related Recoverable Costs (I)		88,192	94,272	98,363	101,155	103,535	140,848	177,052	176,681	176,308	175,937	175,564	175,192	1,683,099
14	Total Juris. Recoverable Costs (Lines 12 + 13)		95,551	102,143	106,574	109,618	112,197	152,632	191,866	191,458	191,054	190,629	190,209	189,803	1,823,734

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 2010 - December 2010

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	0	0	0	0	0	0	0	12,500	12,500	12,500	12,500	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	50,000	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	5,969,275	6,019,275	
3	Less: Accumulated Depreciation (C)	(689,408)	(705,328)	(721,248)	(737,168)	(753,088)	(769,008)	(784,928)	(800,848)	(816,768)	(832,688)	(848,608)	(864,528)	(880,514)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	12,500	25,000	37,500	0	
5	Net Investment (Lines 2 + 3 + 4)	5,279,867	5,263,947	5,248,027	5,232,107	5,216,187	5,200,267	5,184,347	5,168,427	5,152,507	5,149,087	5,145,667	5,142,247	5,138,761	
6	Average Net Investment		5,271,907	5,255,987	5,240,067	5,224,147	5,208,227	5,192,307	5,176,387	5,160,467	5,150,797	5,147,377	5,143,957	5,140,504	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		38,732	38,616	38,499	38,382	38,265	38,147	38,031	37,914	37,843	37,818	37,793	37,767	457,807
	b Debt Component (Line 6 x Debt Component x 1/12)		11,002	10,970	10,936	10,903	10,869	10,836	10,803	10,770	10,750	10,742	10,736	10,728	130,045
8	Investment Expenses														
	a Depreciation (E)		15,920	15,920	15,920	15,920	15,920	15,920	15,920	15,920	15,920	15,920	15,920	15,986	191,106
	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)		65,654	65,506	65,355	65,205	65,054	64,903	64,754	64,604	64,513	64,480	64,449	64,481	778,958
	a Recoverable Costs Allocated to Energy		5,050	5,039	5,027	5,016	5,004	4,993	4,981	4,969	4,962	4,960	4,958	4,960	59,919
	b Recoverable Costs Allocated to Demand		60,604	60,467	60,328	60,189	60,050	59,910	59,773	59,635	59,551	59,520	59,491	59,521	719,039
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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)		4,876	4,869	4,856	4,856	4,845	4,834	4,823	4,809	4,802	4,792	4,785	4,786	57,933
13	Retail Demand-Related Recoverable Costs (I)		58,435	58,303	58,169	58,035	57,902	57,767	57,634	57,501	57,420	57,390	57,362	57,392	693,310
14	Total Juris. Recoverable Costs (Lines 12 + 13)		63,311	63,172	63,025	62,891	62,747	62,601	62,457	62,310	62,222	62,182	62,147	62,178	751,243

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 2010 - December 2010

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		2,739,363	1,543,197	1,567,770	517,669	375,543	282,275	131,864	573	423	423	423	423	
	b Clearings to Plant (J)		2,512,374	1,004,536	1,010,500	131,500	54,733	3,834,289	131,864	573	423	423	423	423	
	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	100,000	
2	Plant-in-Service/Depreciation Base (B) (K)	608,014,996	610,527,370	611,531,906	612,542,406	612,673,906	612,728,639	616,562,928	616,694,792	616,695,365	616,695,788	616,696,211	616,696,634	616,697,057	
3	Less: Accumulated Depreciation (C)	(4,734,904)	(6,357,272)	(7,984,330)	(9,614,075)	(11,245,343)	(12,876,859)	(14,513,403)	(16,155,071)	(17,796,910)	(19,438,750)	(21,080,591)	(22,722,434)	(24,264,278)	
4	CWIP - Non Interest Bearing	2,964,689	3,191,678	3,730,339	4,287,609	4,673,778	4,994,588	1,442,574	1,442,574	1,442,574	1,442,574	1,442,574	1,442,574	1,442,574	
5	Net Investment (Lines 2 + 3 + 4)	606,244,781	607,361,776	607,277,915	607,215,940	606,102,341	604,846,368	603,492,099	601,982,295	600,341,029	598,699,612	597,058,194	595,416,774	593,875,353	
6	Average Net Investment		606,803,279	607,319,846	607,246,928	606,659,141	605,474,355	604,169,234	602,737,197	601,161,662	599,520,321	597,878,903	596,237,484	594,646,064	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		4,458,184	4,461,979	4,461,444	4,457,125	4,448,420	4,438,832	4,428,310	4,416,735	4,404,676	4,392,617	4,380,557	4,368,865	53,117,744
	b Debt Component (Line 6 x Debt Component x 1/12)		1,266,400	1,267,477	1,267,325	1,266,098	1,263,626	1,260,901	1,257,913	1,254,625	1,251,200	1,247,774	1,244,348	1,241,027	15,088,714
8	Investment Expenses														
	a Depreciation (E)		1,613,028	1,617,718	1,620,405	1,621,928	1,622,176	1,627,204	1,632,328	1,632,499	1,632,500	1,632,501	1,632,503	1,632,504	19,517,294
	b Amortization (F)		9,340	9,340	9,340	9,340	9,340	9,340	9,340	9,340	9,340	9,340	9,340	9,340	112,080
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		9,777	9,777	9,777	9,777	9,777	9,777	9,777	9,777	9,777	9,777	9,777	9,777	117,324
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		7,356,729	7,366,291	7,368,291	7,364,268	7,353,339	7,346,054	7,337,668	7,322,976	7,307,493	7,292,009	7,276,525	7,261,513	87,953,156
	a Recoverable Costs Allocated to Energy		7,356,729	7,366,291	7,368,291	7,364,268	7,353,339	7,346,054	7,337,668	7,322,976	7,307,493	7,292,009	7,276,525	7,261,513	87,953,156
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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)		7,101,961	7,116,941	7,117,340	7,129,225	7,118,929	7,111,559	7,104,210	7,086,624	7,071,541	7,045,613	7,022,861	7,007,200	85,034,004
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)		7,101,961	7,116,941	7,117,340	7,129,225	7,118,929	7,111,559	7,104,210	7,086,624	7,071,541	7,045,613	7,022,861	7,007,200	85,034,004

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Beginning Balances: Crist $592,369,378; Smith $11,389,634; Daniel $3,592,561, Scholz $663,423. Ending Balances: Crist $597,134,211; Smith $11,389,634, Daniel $7,509,789, Scholz $663,423.
(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 2010 - December 2010

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)	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	23,654	
3	Less: Accumulated Depreciation (C)	(9,459)	(9,853)	(10,247)	(10,641)	(11,035)	(11,429)	(11,823)	(12,217)	(12,611)	(13,005)	(13,399)	(13,793)	(14,187)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	14,195	13,801	13,407	13,013	12,619	12,225	11,831	11,437	11,043	10,649	10,255	9,861	9,467	
6	Average Net Investment		13,998	13,604	13,210	12,816	12,422	12,028	11,634	11,240	10,846	10,452	10,058	9,664	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		103	100	97	94	91	88	85	83	80	77	74	71	1,043
	b Debt Component (Line 6 x Debt Component x 1/12)		29	28	28	27	26	25	24	23	23	22	21	20	296
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)		526	522	519	515	511	507	503	500	497	493	489	485	6,067
	a Recoverable Costs Allocated to Energy		40	40	40	40	39	39	39	38	38	38	38	37	466
	b Recoverable Costs Allocated to Demand		486	482	479	475	472	468	464	462	459	455	451	448	5,601
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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)		39	39	39	39	38	38	38	37	37	37	37	36	454
13	Retail Demand-Related Recoverable Costs (I)		469	465	462	458	455	451	447	445	443	439	435	432	5,401
14	Total Juris. Recoverable Costs (Lines 12 + 13)		508	504	501	497	493	489	485	482	480	476	472	468	5,855

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 Projected Period Amount
January 2010 - December 2010

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	0	0	0	0	0	0	0	0	0	0	0	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		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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 2010 - December 2010

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		495,000	837,500	1,425,000	0	1,590,000	2,165,000	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	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	3,315,044	1,609,508	2,289,738	3,513,487	3,213,893	4,462,218	6,078,088	5,253,184	4,401,929	3,634,849	2,852,398	2,145,337	1,414,122	
	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	3,315,044	1,609,508	2,289,738	3,513,487	3,213,893	4,462,218	6,078,088	5,253,184	4,401,929	3,634,849	2,852,398	2,145,337	1,414,122	
4	Average Net Working Capital Balance		2,462,276	1,949,623	2,901,612	3,363,690	3,838,056	5,270,153	5,665,636	4,827,557	4,018,389	3,243,623	2,498,867	1,779,729	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12)(A)		18,090	14,324	21,318	24,713	28,198	38,720	41,625	35,468	29,523	23,831	18,359	13,076	307,245
	b Debt Component (Line 4 x Debt Component x 1/12)		5,139	4,069	6,056	7,020	8,010	10,999	11,824	10,075	8,386	6,769	5,215	3,714	87,276
6	Total Return Component (D)		23,229	18,393	27,374	31,733	36,208	49,719	53,449	45,543	37,909	30,600	23,574	16,790	394,521
7	Expenses:														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Annual NOx Allowance Expense		2,200,537	157,270	201,251	299,594	341,674	549,130	824,904	851,254	767,080	782,451	707,061	731,215	8,413,422
8	Net Expenses (E)		2,200,537	157,270	201,251	299,594	341,674	549,130	824,904	851,254	767,080	782,451	707,061	731,215	8,413,422
9	Total System Recoverable Expenses (Lines 6 + 8)		2,223,766	175,663	228,625	331,327	377,882	598,849	878,353	896,797	804,989	813,051	730,635	748,005	8,807,943
	a Recoverable Costs Allocated to Energy		2,223,766	175,663	228,625	331,327	377,882	598,849	878,353	896,797	804,989	813,051	730,635	748,005	8,807,943
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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)		2,146,755	169,716	220,839	320,752	365,836	579,733	850,407	867,853	778,997	785,579	705,164	721,808	8,513,439
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)		2,146,755	169,716	220,839	320,752	365,836	579,733	850,407	867,853	778,997	785,579	705,164	721,808	8,513,439

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

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2010 Projection Filing
Exhibit RWD-3, Page 32 of 88

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2010 - December 2010

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	181,272	180,726	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	67,424	67,424	67,424	67,424	67,424	53,667	219,994	318,241	150,913	(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	67,424	67,424	67,424	67,424	67,424	53,667	219,994	318,241	150,913	(0)	(0)	(0)	(0)	
4	Average Net Working Capital Balance		67,424	67,424	67,424	67,424	60,545	136,831	269,118	234,577	75,456	0	0	0	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12)(A)		495	495	495	495	445	1,005	1,977	1,723	554	0	0	0	7,684
	b Debt Component (Line 4 x Debt Component x 1/12)		141	141	141	141	126	286	562	490	157	0	0	0	2,185
6	Total Return Component (D)		636	636	636	636	571	1,291	2,539	2,213	711	0	0	0	9,869
7	Expenses:														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Seasonal NOx Allowance Expense		0	0	0	0	13,757	14,944	82,480	167,328	150,913	0	0	0	429,422
8	Net Expenses (E)		0	0	0	0	13,757	14,944	82,480	167,328	150,913	0	0	0	429,422
9	Total System Recoverable Expenses (Lines 6 + 8)		636	636	636	636	14,328	16,235	85,019	169,541	151,624	0	0	0	439,291
	a Recoverable Costs Allocated to Energy		636	636	636	636	14,328	16,235	85,019	169,541	151,624	0	0	0	439,291
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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)		614	614	614	616	13,871	15,717	82,314	164,069	146,728	0	0	0	425,157
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)		614	614	614	616	13,871	15,717	82,314	164,069	146,728	0	0	0	425,157

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 2010 - December 2010

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	11,211,121	10,870,694	10,648,304	10,476,406	10,301,005	10,100,120	9,864,471	9,608,069	9,341,597	9,097,980	8,848,146	8,612,760	8,370,807	
	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	(985,309)	(978,915)	(972,521)	(966,126)	(959,732)	(953,337)	(946,943)	(940,549)	(934,154)	(927,760)	(921,366)	(914,971)	(908,577)	
3	Total Working Capital Balance	10,225,812	9,891,779	9,675,783	9,510,280	9,341,273	9,146,782	8,917,528	8,667,521	8,407,443	8,170,220	7,926,780	7,697,789	7,462,230	
4	Average Net Working Capital Balance		10,058,795	9,783,781	9,593,031	9,425,777	9,244,028	9,032,155	8,792,525	8,537,482	8,288,831	8,048,500	7,812,285	7,580,010	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12)(A)		73,902	71,881	70,480	69,251	67,916	66,359	64,599	62,725	60,898	59,132	57,397	55,690	780,230
	b Debt Component (Line 4 x Debt Component x 1/12)		20,993	20,419	20,021	19,672	19,292	18,850	18,350	17,818	17,299	16,797	16,304	15,819	221,634
6	Total Return Component (D)		94,895	92,300	90,501	88,923	87,208	85,209	82,949	80,543	78,197	75,929	73,701	71,509	1,001,864
7	Expenses:														
	a Gains		(6,394)	(6,394)	(6,394)	(6,394)	(6,394)	(6,394)	(6,394)	(6,394)	(6,394)	(6,394)	(6,394)	(6,394)	(76,733)
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c SO2 Allowance Expense		340,427	222,390	171,898	175,401	200,886	235,648	256,402	266,472	243,617	249,834	235,385	241,953	2,840,314
8	Net Expenses (E)		334,032	215,996	165,504	169,006	194,491	229,254	250,008	260,078	237,223	243,440	228,991	235,559	2,763,581
9	Total System Recoverable Expenses (Lines 6 + 8)		428,927	308,296	256,005	257,929	281,699	314,463	332,957	340,621	315,420	319,369	302,692	307,068	3,765,445
	a Recoverable Costs Allocated to Energy		428,927	308,296	256,005	257,929	281,699	314,463	332,957	340,621	315,420	319,369	302,692	307,068	3,765,445
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9646941	0.9654742	0.9652661	0.9674062	0.9674448	0.9674016	0.9675064	0.9670476	0.9670339	0.9655344	0.9644642	0.9643030	
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)		414,073	297,860	247,285	249,697	272,719	304,425	322,363	329,627	305,235	308,578	292,140	296,314	3,640,316
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)		414,073	297,860	247,285	249,697	272,719	304,425	322,363	329,627	305,235	308,578	292,140	296,314	3,640,316

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 2010-December 2010

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 Test 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 and the trailer was replaced in 2005. These replacements provide Gulf with the accuracy and reliability needed to accurately measure SO_2, NOx, and CO_2 and to further maintain compliance with CAAA requirements.

Project-to-Date: Plant-in-service of $220,294 projected at December 2010.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 $14,531,879 projected at December 2010.

Progress Summary: In-Service

Projections: During the 2010 recovery period, Plant Crist plans to begin incurring preliminary engineering and design costs to rebuild portions of the Crist Unit 6 precipitator. Recent inspections of the Plant Crist Unit 6 precipitator have indicated that the internals will need to be replaced by 2013. The 2010 projected expenditures for the Plant Crist Unit 6 precipitator project are $1.1 million.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 2010.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: CEMs – Plant Crist, Scholz, Smith, and Daniel
PEs 1001, 1154, 1164, 1217, 1240, 1245, 1283, 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 $4,021,796 projected at December 2010.

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 were replaced during 2007. During 2008, the opacity, flow, and gas monitors at Plant Smith and opacity and gas monitors at Plant Scholz were replaced.

During 2009, the CEMs project includes the replacement of opacity monitors at Plant Crist on Units 4 and 5 and the installation of CEMs equipment for the new Plant Crist scrubber stack. CEMs equipment will be installed in the scrubber stack to monitor SO_2, NOx, CO_2 and flow pursuant to the CAAA. The 2009 scrubber CEMs expenditures include a new CEMs shelter as well as the monitoring equipment.

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 2010.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 $242,972 projected at December 2010.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 original 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 2010-December 2010

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 2010.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 2010.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 2010.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 being collected at the required compliance point.

Project-to-Date: Plant-in-service of $59,543 projected at December 2010.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 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 the Clean Air Act provisions.

Accomplishments:
The silo storage 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 2010.

Progress Summary: In Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 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 2010.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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. In April 2004 a new waste water treatment facility with additional capacity was installed to replace the facility installed in the 1990's. The new treatment includes aeration and chlorination of the waste water prior to discharge in the Plant Smith ash pond.

Accomplishments: Plant Smith has maintained compliance with the NPDES industrial wastewater permit domestic wastewater treatment requirements.

Project-to-Date: Plant-in-service of $178,962 projected at December 2010.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 $16,192,224 projected at December 2010.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Smith Water Conservation
PEs 1601, 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 for the laboratory sampling system, was installed during 2005 to further reduce groundwater usage.

Accomplishments: Plant Smith estimated that the closed loop cooling project reduced water consumption by approximately 125,000 gallons per day.

Project-to-Date: Plant-in-service of $134,133 projected at December 2010.

Progress Summary: In-Service

Projections: Gulf is currently investigating the feasibility of utilizing reclaimed water at Plant Smith for the Unit 3 cooling tower which would reduce surface water consumption by 5 to 6 million gallons per day. The project expenses have been and will continue to be booked to a preliminary investigation account until Gulf determines whether or not it is able to move forward with the project. If it is feasible to move forward with the project, approximately $1.5 million is projected to be incurred for engineering and design of the infrastructure required to re-use this beneficial water source.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 Gulf's underground storage tanks with new above ground tanks (ASTs). The installation of ASTs significantly reduced the risk of potential petroleum product discharges, groundwater contamination, and subsequent remediation activities.

Accomplishments:
All underground storage 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 2010-December 2010

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 new Crist Unit 7 precipitator 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 $134,681,113 projected at December 2010.

Progress Summary: In-Service

Projections: N/A

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: SPCC Compliance
PEs 1272 & 1401

FPSC Approval: Order No. PSC-03-1348-FOF-EI

Description:
The SPCC Compliance projects were 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. 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 2002 revisions also resulted in oil storage containers having a capacity greater than or equal to 55 gallons being classified as bulk storage containers that are subject to the secondary containment requirements in 40 CFR Part 112.8(c).

Accomplishments: Construction on the Plant Crist switchyard sump was completed during 2006. The sump was designed to route stormwater from the switchyard drains to a new oil skimming sump where any potential spill(s) would be captured, preventing the oil from reaching surface water. During 2009, Plant Smith installed secondary containment for a small fuel tank and a padmount transformer.

Project-to-Date: Plant-in-service of $944,836 projected at December 2010.

Progress Summary: In-service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 2010.

Progress Summary: In-Service

Projections: N/A

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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. Several precipitator upgrades have been 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. The Plant Scholz Unit 2 precipitator upgrade was completed during December of 2007. The Plant Crist Units 4 and 5 precipitator upgrades were placed in-service during March of 2008.

Project-to-Date: Plant-in-service of $29,839,678 projected at December 2010.

Progress Summary: See Accomplishments

Projections: N/A

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 be unable 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 has been canceled 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 2010-December 2010

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Plant Crist Water Conservation Project
PEs 1227 & 1298

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 and surface water withdrawals. Specific Condition six of the Northwest Florida Water Management District (NWFWMD) Individual Water Use Permit Number19850074 issued January 27, 2005 requires Plant Crist to implement measures to increase water conservation and efficiency at the facility. The first Plant Crist Water Conservation project was placed in service during 2006. This project included installing automatic level controls on the fire water tanks to reduce groundwater usage. Gulf Power has entered into an agreement with the Emerald Coast Utilities Authority (ECUA) to begin utilizing reclaimed water from ECUA's proposed wastewater treatment to reduce the demand for groundwater and surface water withdrawals. The NWFWMD has agreed that this is a valid project to pursue for continued implementation of the water conservation effort.

Accomplishments: Level controls were installed on the fire tank system during 2006.

Project-to-Date: Plant-in-service of $16,592,974 projected at December 2010.

Progress Summary: See Accomplishments

Projections: Gulf expects $7.9 million of equipment to be placed in-service during December of 2009 to connect the Plant Crist scrubber project to the ECUA potable water system. Expenditures totaling $8.7 million are projected to be incurred for portions of the Plant Crist Water Conservation project that will be placed-in-service during 2010.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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. During 2008, Plant Crist also installed a chemical treatment system to reduce iron and copper concentrations in the ash pond discharge.

Project-to-Date: Plant-in-service of $6,019,275 projected at December 2010.

Progress Summary: In-Service

Projections: Gulf expects to incur approximately $50,000 of expenditures during 2010 to install an aeration system to reduce copper concentrations in the ash pond discharge.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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

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).

Accomplishments:
Immediately after passage of EPA's CAIR and CAMR in 2005, Gulf began extensive engineering, design, and other planning activities to determine the most cost effective strategy for compliance with the CAIR, CAMR, and CAVR requirements. On March 29, 2007, Gulf petitioned the Commission for approval of the Company's plan to achieve and maintain compliance with the CAIR, CAMR, and CAVR. 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 (the "Plan"). That stipulation identified 10 specific components of Gulf's Plan as being reasonable and prudent for implementation and set forth a process for review in connection with the three remaining components of the 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 into which the Company is moving. The approved plan includes a more detailed discussion of the planning process and evaluation utilized by Gulf to select the most reasonable and prudent strategy for compliance with these regulations on a plant and/or unit specific basis.

Project-to-Date: Plant-in-service of $616,597,057 projected at December 2010.

Progress Summary: See Accomplishments

Projections:
For the purpose of the 2010 projection of ECRC revenue requirements, $8.7 million is projected to be cleared to plant-in-service for the CAIR/CAMR/CAVR Compliance Program. This placed-in-service amount includes expenditures that will be made during 2010 as well as previous years. The two capital projects included in the Compliance Program that will impact the 2010 ECRC revenue requirements are the Plant Crist Units 4 through 7 scrubber ($4.8 million) and the Plant Daniel Unit 1 Low NOx burners ($3.9 million).

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 $23,654 projected at December 2010.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Mercury Allowances

FPSC Approval: Order No. PSC-07-0721-S-EI

Description:
Mercury Allowances were included as part of Gulf's March 2007 CAIR/CAMR/CAVR Compliance Program. The purchase of allowances in conjunction with the retrofit projects comprised the most reasonable, cost-effective means for Gulf to meet the CAIR, CAMR and CAVR requirements. On February 8, 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion vacating EPA's CAMR. The vacatur became effective with the issuance of the court's mandate on March 14, 2008, nullifying CAMR mercury emission control obligations and monitoring requirements. In response to the CAMR vacatur, mercury allowances have been removed from Gulf's Compliance Plan.

Accomplishments: N/A

Project-to-Date: N/A

Progress Summary: N/A

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Annual NO_x Allowances

FPSC Approval: Order No. PSC-07-0721-S-EI

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 / 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 and CAVR requirements.

Accomplishments: N/A

Project-to-Date: N/A

Progress Summary:

Gulf began surrendering annual NOx allowances during 2009.

Projections:

Gulf currently has forward contracts in place to purchase $6.5 million of annual NOx allowances during 2010.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

Description and Progress Report of Environmental Compliance Activities and Projects

Title: Seasonal NO_x Allowances

FPSC Approval: Order No. PSC-07-0721-S-EI

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 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 and CAVR requirements.

Accomplishments: N/A

Project-to-Date: N/A

Progress Summary:

Gulf began surrendering seasonal NOx allowances during 2009.

Projections: Gulf is currently projecting the need to purchase approximately $362,000 seasonal NOx allowances during 2010.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 Acid Rain Program under 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. SO_2 reductions under the CAIR program utilize this program requiring an increased rate of surrender beginning in 2010. Gulf's 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 purchased SO_2 allowances during the 2006, 2007 and 2009.

Project-to-Date: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 2010-December 2010

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) and Mississippi Department of Environmental Quality (MDEQ) under Title IV of the 1990 Clean Air Act Amendments.

Accomplishments:
Fees have been paid by due dates.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $916,374

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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. In May 2009, the Title V renewal applications were submitted for Plant Crist, Smith, Scholz and Pea Ridge. New Title V air operating permits for all of Gulf's generating facilities are expected in December, 2009.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $126,436

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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: $2,600

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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.

Accomplishments:
All systems are in compliance.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $559,914

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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. This line item also includes expenses for Gulf's Cooling Water Intake program and the Impaired Waters Rule.

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: $441,707

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 cleanup operations are initiated.

Accomplishments:
The Florida Department of Environmental Protection has issued a No Further Action (NFA) letter for 50 sites.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $1,630,452

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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. Annual and five year permit renewal fees are required for the 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

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 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: $21,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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: $12,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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. This line item also includes O&M expenses associated with Gulf's Spill Prevention Control and Countermeasures (SPCC) compliance plan.

Accomplishments:
Gulf has complied with all hazardous and solid waste regulations.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $558,133

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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: $98,387

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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 2010-December 2010

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. Plant Crist plans to replace the existing ash curtains and dredge the pond during 2009.

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 2010-December 2010

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.

Accomplishments:
Coal shipments were analyzed as required during 1999. Sampling and analytical requirements are not expected during 2010.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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: $242,989

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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: $2,647,500

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

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

Description: This line item includes the O&M expenses associated with the stipulated portions of Gulf's CAIR, CAMR, and CAVR Compliance program and the Climate Registry. Immediately after the passage of the EPA's CAIR and CAMR in 2005, Gulf began extensive engineering, design, and other planning activities to determine the most cost effective strategy for compliance with the CAIR, CAMR, and CAVR requirements. On March 29, 2007, Gulf petitioned the Commission for approval of the Company's plan to achieve and maintain compliance with the CAIR, CAMR, and CAVR. 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 (the "Plan"). That stipulation identified 10 specific components of Gulf's Plan as being reasonable and prudent for implementation and set forth a process for review in connection with the three remaining components of the 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 into which the Company is moving. The approved plan includes a more detailed discussion of the planning process and evaluation utilized by Gulf to select the most reasonable and prudent strategy for compliance with these regulations on a plant and/or unit specific basis.

Accomplishments:
Gulf began incurring O&M expenses associated with the Crist Units 4 through 7 scrubber, Smith Units 1 and 2 SNCRs, and Scholz mercury monitoring system during 2009.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $20,729,607

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2010-December 2010

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.21

Title: Maximum Achievable Control Technology (MACT)
Information Collection Request (ICR)

Description: EPA recently proposed an extensive Information Collection Request (ICR) in the Federal Register for coal- and oil-fired steam electric generating units to support Maximum Achievable Control Technology (MACT) rulemaking under section 112 of the Clean Air Act (CAA). EPA is currently accepting comments on this proposal and is expected to finalize the ICR in January 2010. The ICR will require submission of information on control equipment efficiencies, emissions, capital and O&M costs, and fuel data for all coal and oil-fired generating units greater than 25 MW. The proposed ICR also requires each of Gulf's facilities to conduct a broad range of emissions testing.

Accomplishments: N/A

Fiscal Expenditures: N/A

Progress Summary: N/A

Projections: $541,000.

Schedule 6P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2010 - December 2010

Rate Class	(1) Average 12 CP Load Factor at Meter (%)	(2) Jan - Dec. 2010 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%	5,571,241,000	1,096,142.86	1.0048648	1.0053010	5,600,773,981	1,101,475.33	49.79563%	58.83889%
GS	63.781436%	313,549,000	56,118.62	1.0048589	1.0052978	315,210,104	56,391.29	2.80248%	3.01232%
GSD, GSDT, GSTOU	75.860452%	2,435,322,000	366,468.68	1.0047057	1.0051660	2,447,902,971	368,193.15	21.76393%	19.66823%
LP, LPT	86.886296%	1,885,643,000	247,744.54	0.9842260	0.9891199	1,865,126,997	243,836.61	16.58256%	13.02532%
PX, PXT, RTP, SBS	104.683592%	883,147,000	96,305.32	0.9744382	0.9805725	865,989,688	93,843.58	7.69938%	5.01296%
OS-I/II	321.885641%	115,537,000	4,097.47	1.0046893	1.0052949	116,148,751	4,116.68	1.03266%	0.21991%
OS-III	99.718369%	36,179,000	4,141.69	1.0051151	1.0052683	36,369,601	4,162.88	0.32336%	0.22237%
TOTAL		11,240,618,000	1,871,019.18			11,247,522,093	1,872,019.52	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 2010 - December 2010
(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

Schedule 7P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2010 - December 2010

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	49.79563%	58.83889%	73,117,464	4,370,738	77,488,202	5,571,241,000	1.391
GS	2.80248%	3.01232%	4,115,024	223,765	4,338,789	313,549,000	1.384
GSD, GSDT, GSTOU	21.76393%	19.66823%	31,957,089	1,461,018	33,418,107	2,435,322,000	1.372
LP, LPT	16.58256%	13.02532%	24,349,019	967,562	25,316,581	1,885,643,000	1.343
PX, PXT, RTP, SBS	7.69938%	5.01296%	11,305,392	372,379	11,677,771	883,147,000	1.322
OS-I, OS-II	1.03266%	0.21991%	1,516,307	16,336	1,532,643	115,537,000	1.327
OS-III	0.32336%	0.22237%	474,806	16,518	491,324	36,179,000	1.358
TOTAL	100.00000%	100.00000%	$146,835,101	$7,428,316	$154,263,417	11,240,618,000	1.372

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 2010 - December 2010
(7) Col 5 / Col 6 x 100