BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 090007-EI
FLORIDA POWER & LIGHT COMPANY

AUGUST 28, 2009

ENVIRONMENTAL COST RECOVERY

PROJECTIONS
JANUARY 2010 THROUGH DECEMBER 2010

TESTIMONY & EXHIBITS OF:

T.J. KEITH
R. R. LABAUVE

COM 5
ECR
GCL 2
OPC
RCP 2
SSC
SGA 1
ADM
CLK 1

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY J. KEITH

DOCKET NO. 090007-EI

AUGUST 28, 2009

Q. Please state your name and address.

A. My name is Terry J. Keith and my business address is 9250 West Flagler Street, Miami, Florida, 33174.

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

A. I am employed by Florida Power & Light Company (FPL or the Company) as Director, Cost Recovery Clauses in the Regulatory Affairs Department.

Q. Have you previously testified in this docket?

A. Yes, I have.

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

A. The purpose of my testimony is to present for Commission review FPL's Environmental Cost Recovery Clause (ECRC) projections for the January 2010 through December 2010 period.

Q. Is this filing by FPL in compliance with Order No. PSC-93-1580-FOF-EI, issued in Docket No. 930661-EI?

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

Q. Have you prepared or caused to be prepared under your direction,

supervision or control an exhibit in this proceeding?

A. Yes. Exhibit TJK-3 consists of seven documents, PSC Forms 42-1P through 42-7P provided in Appendix I. Form 42-1P summarizes the costs being presented at this time. Form 42-2P reflects the total jurisdictional costs for O&M activities. Form 42-3P reflects the total jurisdictional costs for capital investment projects. Form 42-4P consists of the calculation of depreciation expense and return on capital investment for each project. Form 42-5P gives the description and progress of environmental compliance activities and projects for the projected period. Form 42-6P reflects the calculation of the energy and demand allocation percentages by rate class. Form 42-7P reflects the calculation of the 2010 ECRC factors.

Q. Please describe Form 42-1P.

A. Form 42-1P (Appendix I, Page 2) provides a summary of projected environmental costs being presented for the period January 2010 through December 2010. Total environmental costs, adjusted for revenue taxes, amount to $168,558,816 (Appendix I, Page 2, Line 5) and include $174,734,516 of environmental project costs (Appendix I, Page 2, Line 1c) decreased by the estimated/actual true-up over-recovery of $3,602,753 for the January 2009 - December 2009 period (Appendix I, Page 2, Line 2), and by the final true-up over-recovery of $2,694,222 for the January 2008 – December 2008 period (Appendix I, Page 2, Line 3).

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

A. Form 42-2P (Appendix I, Pages 3 and 4) presents the environmental project O&M costs for the projected period along with the calculation of total jurisdictional costs for these projects, classified by energy and demand. Form 42-3P (Appendix I, Pages 5 and 6) presents the environmental project capital investment costs for the projected period. Form 42-3P also provides the calculation of total jurisdictional costs for these projects, classified by energy and demand.

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

Q. Please describe Form 42-4P.

A. Form 42-4P (Appendix I, Pages 7 through 65) presents the calculation of depreciation expense and return on capital investment for each project for the projected period.

Q. Please describe Form 42-5P.

A. Form 42-5P (Appendix I, Pages 66 through 123) provides the description and progress of environmental projects included in the projected period.

Q. Please describe Form 42-6P.

A. Form 42-6P (Appendix I, Page 124) calculates the allocation factors for demand and energy at generation. The demand allocation factors are calculated by determining the percentage each rate class contributes to the monthly system peaks. The energy allocators are calculated by determining the percentage each rate contributes to total kWh sales, as adjusted for losses, for each rate class.

Q. Please describe Form 42-7P.

A. Form 42-7P (Appendix I, Page 125) presents the calculation of the proposed 2010 ECRC factors by rate class.

Q. Is FPL proposing any adjustments in its base rate proceeding (Docket No. 080677-EI) that impact the ECRC?

A. Yes. In the testimonies of Kim Ousdahl and Marlene Santos filed in Docket No. 080677-EI, FPL discusses several adjustments to move items between base rates and clause recovery. One adjustment impacting the ECRC is to recover bad debt expense associated with clause revenues through the related cost recovery clause instead of base rates.

Q. Has FPL included this proposed adjustment in the calculation of its 2010 ECRC factors?

A. No, however FPL has quantified the impact of this adjustment on the ECRC and will revise its 2010 ECRC factors to be consistent with the Commission's decision in Docket No. 080677-EI.

If approved in Docket No. 080677-EI, the bad debt expense associated with ECRC revenues for 2010 will be $496,753. This amount does not result in an increase to the ECRC portion of the 2010 Residential 1,000 kWh bill.

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

A. Yes, with the exception the National Emission Standard for Hazardous Air Pollutants (NESHAP) Information Collection Request Project, the Turkey

Point Cooling Canal Monitoring Plan, and the Manatee Temporary Heating System Project, which are discussed and supported in the testimony of Randall R. LaBauve.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RANDALL R. LABAUVE

DOCKET NO. 090007-EI

AUGUST 28, 2009

Q. Please state your name and address.

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

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

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

Q. Have you previously testified in this docket?

A. Yes, I have.

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

A. The purpose of my testimony is to present for Commission review and approval a new environmental project – The National Emission Standards for Hazardous Air Pollutants (NESHAP) Information Collection Request (ICR) Compliance Project. Additionally, my testimony discusses the expansion of the Manatee Temporary Heating System (MTHS) Project originally filed in this docket on April 13, 2009, to cover the Cape Canaveral Plant (PCC). Finally, my testimony provides a brief update on the St. Lucie Cooling Water System Inspection and Maintenance Project, approved in Docket No. 070007-EI, Order No. PSC-07-0922-FOF-EI, issued on November 16, 2007.

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

A. Yes. I am sponsoring the following exhibits:

- RRL-4 – NESHAP ICR Public Notice
- RRL-5 – Electric Utility Steam Generating Unit Hazardous Air Pollutant Information Collection Effort Burden Statement - Part B
- RRL-6 – Florida Department of Environmental Protection (FDEP) Industrial Wastewater Facility (IWWF) Permit Number FL0001473 for Plant Cape Canaveral (PCC)
- RRL-7 - PCC Manatee Protection Plan (MPP)
- RRL-8 – U.S. Fish and Wildlife Service (USFWS) letter to FPL
- RRL-9 – Florida Fish and Wildlife Conservation Commission's (FWC) "FWC Staff Report For Florida Power and Light Company – Cape Canaveral Energy Center (CCEC)"
- RRL-10 – Manatee Heating System Conceptual Location of Pumps and Heater

<u>NESHAP ICR Compliance Project</u>

Q. Please describe the law or regulation requiring the NESHAP ICR Compliance Project.

A. The Environmental Protection Agency (EPA) regulates Hazardous Air Pollutants (HAPs) through authority granted to the agency under Section 112 of the Clean Air Act (CAA). EPA promulgates NESHAP emission standards under 40 CFR Part 63 for stationary source categories. In setting HAP emission limitations and performance standards for source categories EPA reviews available information and where additional information is needed EPA issues an ICR to affected sources under authority granted to it by Section 114 of the CAA.

The ICR for NESHAP for coal and oil-fired utility steam generating units was proposed by the EPA and noticed in the Federal Register on July 2, 2009. The NESHAP ICR Public Notice is included as Exhibit RRL-4. EPA has proposed to require survey information, fuel analyses, and emission stack testing to determine whether coal and oil-fired electric utility steam generating units emit HAPs listed under CAA section 112(b). FPL anticipates that the final ICR will be published in the Federal Register by December of 2009. To comply with the EPA deadlines, FPL will need to complete all required activities within six months of issuance of the final ICR. To comply with the March 13, 2007 D.C. Circuit Court of Appeals decision on Maximum Achievable Control Technology standards and the court's vacatur of the Clean Air Mercury Rule, EPA has proposed the NESHAP ICR to collect sufficient information to identify HAP emission standards for the best performing sources for coal and oil-fired utility steam generating units.

Q. Why has FPL proposed the NESHAP ICR project prior to EPA publishing a final ICR?

A. FPL anticipates that EPA will propose a final ICR for coal and oil-fired utility steam generating units this year as a result of the U.S. Court of Appeals decision, which requires that EPA gather sufficient data prior to setting a new standard and also as a result of the Court's vacatur of the Clean Air Mercury Rule, which requires that EPA establish standards for mercury and nickel emissions from coal and oil-fired steam electric generating units. As I've stated earlier, the proposed ICR would require emission testing and fuel analyses to be completed within six months of the final ICR at 471 plants across the U.S. for which there exists a limited number of companies that have demonstrated expertise in the analyses specified by EPA. FPL believes it must begin its plan to respond to a final ICR due to the near certainty that the ICR will be issued, due to the short time frame in which FPL would be required to respond, and also due to the limited availability of contractors needed for emission testing and fuel analyses.

Q. Does FPL plan to file comments with EPA regarding the ICR?

A. Yes. FPL will file specific comments related to several aspects of the proposal including the scope of the information request and extensive proposed testing, the requirement to test sources which will be replaced, and the relatively short proposed timelines for compliance with the ICR.

Q. How will the NESHAP ICR affect FPL?

A. FPL currently owns and operates 17 oil-fired electric utility steam generating units and owns a portion of 3 coal-fired electric utility steam generating units that are the subject of the proposed ICR. EPA's proposed ICR requires that FPL provide historical baseline operating and fuel quality data for all of its existing coal and oil-fired electric utility steam generating units for its survey and also provide additional data obtained through fuel sampling and stack emission testing for a portion of the affected units. For its co-owned coal-fired units FPL will require the operators of those units to complete reporting requirements and to arrange for fuel and emission testing where required by the ICR under the terms of its operating agreements. FPL would be responsible for its share of costs for compliance with the ICR.

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

A. The information collection for this ICR consists of two components: 1) the preparation, submittal, and quality assurance check of data from all coal- and oil-fired units and 2) the emission stack testing, fuel testing, and quality assurance of data for units and facilities identified in the ICR Statement of Burden – Part B, which is included as Exhibit RRL-5.

As to the first component, EPA has proposed to collect the data required for all affected units through use of an electronic survey. FPL is currently evaluating resource needs associated with the required data collection, submittal and quality assurance. FPL has identified that it will need contractor services to assist in the collection and submittal of the first component of the ICR to comply with the EPA required submittal of survey results within 3 months of the published date of the final ICR.

For the second component of the ICR, FPL will use outside consulting firms for emission stack testing activities, required coal and oil testing for HAPs identified in the ICR, and for the data entry and quality assurance of test data submitted to EPA for the ICR. Results of stack testing and fuel analyses must be submitted to EPA within 6 months of the final published date of the ICR.

Q. What are the compliance dates for this project?

A. Comments on the proposed ICR must be filed by August 31, 2009. Based on promulgation of previous EPA ICRs, FPL anticipates that the EPA's proposed NESHAP ICR will be approved by the Office of Management and Budget and published in the Federal Register by November or December of 2009. Compliance deadlines for submittal of information would likely be February or March of 2010 for submittal of survey information and May or June of 2010 for stack emission testing and fuel analyses.

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

A. No. FPL is only requesting recovery of incremental activities associated with NESHAP ICR Project compliance with EPA requirements. Costs associated with similar activities required to comply with existing state and federal regulations are not included in FPL's estimates for this project.

Q. Has FPL estimated the cost of the NESHAP ICR Project?

A. The total cost of the project will depend on the requirements established in the final NESHAP ICR published in the Federal Register. To estimate the project costs for the NESHAP ICR, FPL has preliminarily relied upon the EPA estimates from the ICR Statement of Burden- Part B for those activities which FPL anticipates will be performed by outside firms. Costs for activities identified in the ICR which FPL expects to be completed by in-house resources have not been included in estimates and FPL does not plan to recover those costs through the ECRC NESHAP ICR Project. Specific details related to EPA's estimates for costs are provided in the ICR Statement of Burden – Part B. FPL has estimated a preliminary ECRC NESHAP ICR project cost of approximately $3.3 million for contractor and professional services required by the project. Because of EPA's tight compliance deadlines in the proposed rule, FPL anticipates that all of the costs associated with the ICR Project will be incurred in 2010.

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

A. Consistent with our standard practice for all contractor services procurements, FPL proposes to competitively bid stack emission testing, fuel analyses, and quality assurance activities to ensure costs for activities performed by outside firms are prudently incurred. FPL will revise project estimates as specific costs become available through contractor specific bids and costs.

Manatee Temporary Heating System Project – Cape Canaveral Plant

Q. Please briefly describe FPL's filing dated April 13, 2009, requesting approval of the MTHS Project.

A. On April 13, 2009, FPL petitioned and I filed testimony in this docket requesting recovery of the MTHS Project, for the installation of an electric heating system at the Riviera Plant (PRV) in 2009, in order to provide a "manatee refuge" by discharging warm water when necessary into the manatee embayment area until PRV is converted to the Riviera Beach Next Generation Clean Energy Center. The MTHS Project will ensure that FPL complies with its PRV MPP, which is required by Specific Condition 9 (originally numbered 13) to the IWWF Permit Number FL00001546, issued by the FDEP for PRV on February 10, 2004.

Primary activities integral to the MTHS Project at PRV include installing the pipes, pumps, and heater, interconnection to the FPL power system, and testing and operating the system.

Q. Was FPL considering the need for a temporary heating system at PCC at the time of your April 13, 2009 filing?

A. Yes. In my testimony dated April 13, 2009, I mention that the IWWF permit and the MPP for PCC have similar requirements for maintaining water temperatures to protect manatees and that FPL would amend its MTHS Project to include the costs for a system at PCC. However, FPL's plans for PCC were not sufficiently finalized at that time to include them in the petition or my testimony.

Q. Please briefly describe FPL's proposed project at PCC.

A. In September 2008, FPL received a Determination of Need from this Commission to undertake a major modernization project at PCC, which will convert the existing conventional steam units into a highly efficient, clean-burning, gas-fired combined cycle unit (the "Modernization Project") to be named the Cape Canaveral Next Generation Clean Energy Center (CCEC).

The activities at PCC will include the installation of an electric heating system, pumps, piping, interconnection to the FPL electrical distribution system testing and operating the system in 2010, monitoring the physical conditions of the manatee embayment area, monitoring manatee distribution and abundance and engaging with jurisdictional agencies to begin long-term planning to reduce potential adverse affects from any future reduction of warm water production at the CCEC.

Since the original MTHS filing, the activities under the MTHS Project at PCC have been better defined since FWC proposed its Conditions of Certification for the project in August 2009.

Q. Please describe the environmental law or regulation requiring the MTHS Project at PCC.

A. FPL is proposing the MTHS Project at PCC in order to ensure compliance with PCC's existing MPP during the construction of CCEC, affirmatively respond to the USFWS letter of June 24, 2008, and comply with FWC's proposed Conditions of Certification for the CCEC.

The FDEP issued IWWF Permit Number FL0001473 to FPL's PCC on August 10, 2005. Specific Condition 9 of the IWWF permit states that "the Permitee shall continue compliance with the facility's MPP approved by the Department on December 21, 2000." The MPP requires FPL to provide warm water for manatees during winter months when certain weather conditions are present. FPL will apply for a renewal of the PCC IWWF permit in late January 2010.

The IWWF permit containing Specific Condition 9 is included as Exhibit RRL-6 and FPL's MPP for PCC is included as Exhibit RRL-7. Note that the Manatee Protection Plan refers to "Specific Condition 13," which has been renumbered as Specific Condition 9 in the current IWWF permit.

On June 24, 2008, the FWS provided comments in a letter to FPL regarding the Modernization Project. The FWS indicated that measures would be necessary to protect the manatees from cold water impacts during the transition period of the Modernization Project. A copy of the FWS letter to FPL is included as Exhibit RRL-8. Further, the manatees are protected by the federal Marine Mammal Protection Act of 1972 (16 U.S.C. 1361, et. seq.) and the Endangered Species Act of 1973 (16

U.S.C. 1531, et. seq.). Additionally, the Indian River Lagoon is considered by the USFWS as Critical Habitat for the manatee (42 FR 47840).

As a commenting agency to the Florida Electrical Power Plant Siting Act Site Certification process, FWC proposed Conditions of Certification regarding manatee protection to be required in the final Conditions of Certification. FWC subsequently wrote its agency report ("FWC Staff Report for Florida Power and Light Company – Cape Canaveral Energy Center (CCEC)") and filed it with the FDEP as part of the FPL CCEC Site Certification Application process. In the report, FWC has proposed Conditions of Certification regarding protections for the manatees in the interim period between PCC decommissioning and CCEC post-commercial operation, which is September 2010 through March 2015.

The Conditions of Certification include specific actions FPL must take in exchange for FWC's approval of CCEC. The proposed Conditions of Certification address the Interim Warm-Water Refuge Heating System for manatee protection, environmental monitoring, biological monitoring, and the development of a long-term manatee strategy. A copy of the "FWC Staff Report for Florida Power and Light Company – Cape Canaveral Energy Center (CCEC)" is included as Exhibit RRL-9.

Q. **How has FPL complied with the PCC MPP in the past?**

A. FPL has successfully complied with the PCC MPP in the past by discharging warm water from plant operation into the Indian River Lagoon via two once-through cooling water discharge structures (one discharge structure per unit). As noted in the MPP, at times when the ambient water temperature has fallen below 61°F as measured at the plant intake, PCC has endeavored 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 reached 61°F, unless otherwise authorized by the Bureau of Protected Species Management (BPSM) and the USFWS, or unless safety or reliability of the plant would have been compromised.

Q. When will FPL begin the MTHS Project at PCC?

A. FPL will begin the MTHS Project at PCC upon receipt of the CCEC Site Certification determination from the Siting Board. FPL's current MTHS Project schedule assumes the Siting Board determination will be received January 19, 2010.

Q. Why does the heating system at PCC need to be installed in 2010?

A. Decommissioning of PCC is scheduled for April 2010. To comply with FWC's conditions of certification for CCEC and allow time for testing prior to the winter manatee season, FPL must install the heating system by September 15, 2010.

Q. What is a manatee embayment area?

A. The term "manatee embayment" refers to the PCC 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. The embayment opens into the Indian River Lagoon. The location of the manatee embayment is shown on Exhibit RRL-10.

Q. **What is the significance of FPL providing warm water to the embayment area?**

A. The Florida manatee, a subspecies of the West Indian manatee found only in the southeastern United States, is listed as endangered under both the U.S. Endangered Species Act and Florida state law. Most manatees congregate at confined warm-water refuges when coastal water temperatures begin to fall below 68°F. The exact threshold at which manatees succumb to cold and die is uncertain and can vary between individual manatees. However, when extremely cold winter temperatures occur, large numbers of manatees may die or have their health impaired. Many of the natural warm water habitats historically used by manatees are no longer available to them. The outflows from power plants, like PCC, have provided a substitute for these lost natural resources.

Manatees are known to inhabit the Indian River Lagoon year-round, and they congregate at the PCC discharge area during colder temperatures because of the warm water discharged from the plant.

Q. **How many manatees can be found in Indian River Lagoon and the discharge area?**

A. On February 6, 2009, 540 manatees were sighted in the vicinity of PCC during an aerial survey.

Q. Why does FPL now need a different heating source for PCC?

A. Implementing the Modernization Project will require that the existing PCC units be dismantled and substantially rebuilt. During this construction period, the units will not be available to provide warm water for compliance with the MPP. The current schedule for the Modernization Project requires that the existing conventional steam units be taken out of service no later than April 2010 to begin the conversion.

Q. Please describe the heating system to be installed at PCC.

A. The heating system to be installed at PCC will include a 30-million Btu per hour electric heating system including pumps, piping, and electrical equipment. The electric heating system will be located to discharge warm water into the western end of the intake canal, where the water depth is approximately 11.5 to 14 feet deep. The intake for the system will be located approximately 1,000 feet east of the system discharge. When the ambient water temperature falls below an established threshold, sea water will be pumped from the intake location through an inlet pipe to the heater, and the heated water will be discharged into the west end of the intake canal, which will serve as the interim period manatee embayment area. The heating system is predicted to provide approximately 2.05 acres of water at or above 68°F during conditions under which heating is needed. A conceptual location of the heating system is included in Exhibit RRL-10.

Q. How did FPL determine the size of the electric heater?

A. To determine the size of the heater required to comply with the MPP obligation, FPL retained an environmental services firm (Golder Associates) to develop a computer model to calculate the required thermal outputs of the heating system.

Q. **What conclusions did FPL reach regarding the alternatives for providing warm water to manatees at PCC?**

A. As I discussed earlier, FPL will need a heating system at PCC because there will be no other viable source of warm water for manatees during the construction of the Modernization Project. All alternatives considered included a boiler or heater as part of an intake and discharge system that could be installed and operated to provide a sufficient warm water area. After studying commercially available system components, it was concluded that the heating system chosen was the best alternative for FPL to pursue, resulting in the most cost effective means to produce warm water for the manatees.

Q. **What will happen to the MTHS at PCC when the modernization is completed in 2013?**

A. The PCC MTHS is specifically required during the modernization process. FPL will evaluate the disposition of the MTHS at PCC as the modernization process is being completed. This evaluation will take into account providing the maximum value for FPL's customers while providing the desired environment for the manatees.

Q. **What resources does FPL anticipate will be needed to operate the MTHS at PCC?**

A. Based on FPL's earlier work on the MTHS at PRV, FPL anticipates using two operators. These operators will be incremental employees whose sole responsibility will be to operate, maintain, and repair the MTHS and these operators will be trained on the operation and maintenance of the MTHS at PCC. Each operator will work separately in a twelve-hour shift during weather critical days. Furthermore, FPL will develop a Best Management Practices (BMP) manual that will address, among other topics, operations, maintenance, troubleshooting, and repair of the MTHS at PCC.

Q. Please describe the other Conditions of Certification relevant to the MTHS project at PCC.

A. As found in the environmental monitoring section of the proposed Conditions of Certification for the CCEC project, FWC requires FPL to monitor the physical conditions in the manatee embayment area. FWC also requires FPL to monitor manatee distribution and abundance as prescribed in the biological monitoring section of the proposed Conditions of Certification for the CCEC project. The development of a long-term manatee strategy in the proposed Conditions of Certification requires FPL to engage with jurisdictional agencies to begin long-term planning to reduce potential adverse affects from any future reduction of warm water production at CCEC.

Q. Please describe the activities and resources FPL anticipates are needed to comply with the PCC Conditions of Certification.

A. Environmental monitoring includes writing an Environmental Monitoring Plan, evaluating the heating system, deploying temperature monitoring stations to measure air and water temperatures, and preparing environmental monitoring reports. Biological monitoring includes writing a Biological Monitoring Plan, conducting aerial surveys, tagging manatees and conducting telemetry studies, hiring specially-trained manatee observers, providing manatee observation platforms, and preparing biological monitoring reports. FPL will also perform activities required under the long-term manatee strategy mentioned above. Most, if not all, of the long-term strategy activities will occur after 2015 because of the requirements to coordinate activities with agencies protecting the manatees and the need to have future plant life plans for CCEC developed.

Q. Has FPL estimated the cost of the proposed MTHS project and associated activities needed to comply with the PCC Conditions of Certification?

A. Estimated capital costs for the heating system in 2010 are $4.68 million. This estimate includes expenditures for the equipment, design and engineering of the system, labor for installation, interconnection to the FPL power system, and the development of the BMP manual.

After installation and commissioning is complete, FPL expects to incur O&M costs associated with materials and supplies necessary to maintain the heating system at PCC. FPL's annual O&M estimates for years 2010 through 2015 are $202,249, $318,931, $286,600, $298,000, $268,000, $138,500 respectively. The materials and supplies which are expected to be required for operation and maintenance of the heating system may include replacement heating elements, heater control components, electrical fuses, pump seals, and miscellaneous consumable items such as grease/oil for motor maintenance, gaskets, paint and rags. These projected O&M costs do not include the energy costs to operate the heating system. FPL cannot predict how often the system will operate, however, the energy costs will not be significant nor will they be recovered through the ECRC process.

Regarding compliance with the additional PCC Conditions of Certification, FPL estimated that environmental monitoring will cost a total of $865,000 which includes expenses for consultants, instruments, equipment, and production of documents. Biological monitoring is estimated to total $920,000, which includes expenses for consultants, survey flights, instruments, equipment, and production of documents. The development of a long-term manatee strategy is estimated to total $110,000 which includes expenses for consultants, workshops, and production of documents.

Q. Has FPL estimated its 2010 ECRC recovery amount for the MTHS project and related PCC Conditions of Certification?

A. FPL plans to place the heating system at PCC into service by September 15, 2010. Based on that in-service date, FPL has projected approximately $160,684 in amortization expense and return on investment associated with this heating system during the remainder of

2010. During 2010, FPL projects spending approximately $202,249 for environmental monitoring, biological monitoring and the long-term strategy development, which are required by the PCC Conditions of Certification.

Q. Please describe the measures FPL has taken to ensure that costs of the PCC MTHS project and related PCC Conditions of Certification have been minimized.

A. FPL's Engineering and Construction Division has retained an engineering firm, Worley Parsons, to perform a study to identify the most cost-effective approach to providing a heating system at PCC. Using a performance specification for the recommended heater, FPL's Integrated Supply Chain (ISC) group, participating in the MTHS Project, solicited bids from multiple suppliers, identified the supplier that provided the overall best value, and has secured pricing for the heater component of the PCC MTHS. The ISC group provides enterprise-wide leadership, direction, and operation of a fully integrated supply chain that will also support the procurement of other materials and equipment, as well as the construction services needed to complete the MTHS at PCC. ISC's objective is to drive down costs to FPL and ensure the delivery of the highest quality goods and services.

FPL's Project Controls group has established a scope, budget, and schedule to meet the needs of the MTHS Project. Project Controls is also responsible for tracking all MTHS Project costs through various approval processes, procedures, and databases.

Regarding the FWC Conditions of Certification, FPL has developed its estimates by working with the FWC staff and an independent expert in manatee studies to assess the costs and expenses for environmental monitoring, biological monitoring, and developing a long-term manatee strategy.

Q. Is FPL recovering through any other mechanism the costs for the PCC MTHS project and related PCC Conditions of Certification for which it is petitioning for ECRC recovery?

A. No.

St. Lucie Cooling Water System Inspection and Maintenance Project Update

Q. Please provide an update on the St. Lucie Cooling Water System Inspection and Maintenance Project.

A. As I will explain below, the St. Lucie Cooling Water System Inspection and Maintenance Project (the "Project) has evolved substantially as to the required scope of project activities. In addition, FPL has encountered considerable challenges related to the conditions under which the Project work must be performed.

Q. Please describe the evolution of the scope of Project activities.

A. In anticipation of a Biological Opinion (BO) to be issued by the National Marine Fisheries Service (NMFS) pursuant to section 7 of the federal Endangered Species Act, 16 USC Section1531 (ESA), on January 5, 2007, FPL submitted a petition to the Florida Public Service Commission (FPSC) for approval of the Project. In the affidavit supporting the petition, FPL stated that the purpose of the Project was to inspect and, as necessary, clean up or repair any conditions found during the inspection that could contribute to injuries and/or deaths of endangered species, thus helping to keep FPL in compliance with the ESA. The affidavit further stated that, while the initial project activity consisted of inspection and cleaning of the intake pipes, additional inspection, maintenance and/or modification activities could be required in the future to comply with the ESA.

The major change to the required scope relates to the decision by the NMFS that FPL needs to install exclusion devices at the velocity cap openings in order to prevent large organisms such as adult sea turtles from entering the intake pipes. This change in the NMFS's position is largely a result of the discovery that a nesting female sea turtle had been drawn through an intake pipe into the cooling canal and laid eggs on the bank of the canal, and that the hatchlings then were drawn into plant cooling water intakes where they were trapped and died.

On August 4, 2008, I filed an update to the Project providing details on the specifications of the exclusion device, stating "the exclusion devices consist of a support structure installed in the opening of the velocity caps, which will support panels containing a mesh with 20 inch openings installed at approximately 45 degrees." The testimony also stated that the conceptual design had been submitted to the Nuclear Regulatory Commission (NRC) for review. Although the devices are intended to exclude a variety of sea life, I will refer to them as "turtle excluders" for simplicity.

Q. What is the status of the inspection and cleaning of the St. Lucie Plant Cooling Water System?

A. The inspection of the intake pipes and velocity caps was completed during the scheduled 2007 Spring refueling outage. The results of the inspection provided details for what additional work was needed to clean and remove/minimize debris or structural obstructions.

FPL established a project team to plan and manage the scope of the pipe cleaning and debris removal. Generally, the cleaning included the ceiling, floor and columns of the velocity caps, along with the vertical risers and the easternmost 375' of the intake pipes. The work also called for removal of marine growth, unevenness of the concrete and other obstacles and protrusions that could potentially harm marine life.

As with the inspection work, the cleaning and debris removal has to be performed during unit outages, to allow the flow in the pipe that is being cleaned to be blocked off for safety reasons. Initially, FPL expected to complete that work during scheduled outages in 2007, but that has not proved to be possible. The 12' diameter south intake pipe and 200' of the 12' diameter north intake pipe were completed in 2007, representing approximately 57% of the estimated total footage. The vertical risers for the two 12' velocity cap structures were also completed in 2007, representing approximately 66% of the total area. The 2007 cleaning work was delayed approximately 40% of the calendar time because of adverse weather conditions.

No pipe cleaning work was performed during the scheduled 2008 Fall refueling outage because of adverse weather conditions. Work also could not be performed during the scheduled 2009 Spring refueling outage because of a very short outage window. Therefore, the remaining intake pipe and velocity cap cleaning has been scheduled for the 2010 and 2012 Spring refueling outages.

Q. Please describe the adverse weather conditions that have led to project delays.

A. Weather conditions have a direct impact on the diving operations since the cleaning of the intake pipe and velocity caps is performed manually by divers. Diving operations are considered a high risk activity. Because of the high risk nature of diving operations and the importance of diver safety, very stringent dive rules are in place to protect divers. The dive restrictions are very dependent on sea conditions which are, in turn, greatly influenced by the weather conditions. In addition to storms and lightning, sea conditions such as wave height, wave surge, and visibility are influenced by the weather and have limits that restrict when divers can be in the water. Although conditions are generally good for dive operations during the spring and summer months when the cleaning is performed, during the duration of the Project, weather has often resulted in lost time or non-productive days where weather would not allow dive operations to start or days when weather limited productive dive time.

Q. Please describe the activities that FPL is undertaking as a result of the NMFS requirement that turtle excluders be installed.

A. The 2007 inspection identified inconsistencies in the size and shape of the windows in the velocity cap structures where the turtle excluders are to be installed. These inconsistencies are believed to be due to a combination of biofouling, marine growth, protrusions of various construction materials in the velocity cap windows and the uneven placement of concrete. Together, these factors have made it impractical to design and install turtle excluders having standard dimensions, meaning that each excluder would have to be customized to the window where it would be installed. Therefore, unless steps are taken to allow the installation of standardized excluders, the design, testing, and installation would not be cost effective. In addition, the reduced area of the windows due to the obstructions has created vortices from which organisms cannot escape. Cost estimates to remove this excess concrete (by concrete cutting methods) as well as other obstacles and protrusions in the window openings were not contemplated in any of the original project cost projections.

The removal of excess concrete required for the installation of the turtle exclusion devices is scheduled to resume in 2010 and continue through 2012. The concrete removal in the 16' pipe will be completed in 2011, which in turn will allow the 16' velocity cap turtle exclusion devices to be installed. The 12' velocity caps' concrete removal is expected to be completed in the Spring of 2012, and the turtle exclusion devices installed in the Summer of 2012.

Q. **What impact have these challenging work conditions and scope changes had on the projected cost of the Project?**

A. As one would expect, they have increased the projected cost considerably. The original cost estimate for the inspection and cleaning/debris removal was approximately $3 million to $6 million, although the petition cautioned at the time that the full scope and hence cost of the Project could not be predicted until the inspection was complete. In 2008, I estimated the cost of the turtle excluders to be approximately $3.75 million. However, those estimates did not take into account (1) the extremely adverse work conditions that would drastically limit the amount of productive dive time, or (2) the need to physically cut out large sections of concrete and other protrusions in order to eliminate dangerous obstacles and create regular window dimensions for the turtle excluders. These changed conditions have increased FPL's estimate of the total project cost from the approximately $10 million just mentioned, to over $21 million today.

FPL's estimated costs for 2010 are $4.2 million. Of that total, $2.8 million of capital expenses are projected for concrete removal activities, and $1.4 million of O&M expenses projected for pipe cleaning activities.

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

A. Consistent with our standard practice for all contractor services procurements, FPL competitively bid all of the concrete cutting and diving activities to ensure costs for activities performed by outside firms were prudently incurred. FPL will revise project estimates as specific costs become available through contractor specific bids and costs. FPL will continue to perform due diligence over the life of this project to minimize costs, which may include investigating alternative concrete cleaning and cutting techniques, changes in diving operations that may include changes to types of work platforms and stations, diver working hours, or other methodologies to ensure the projects costs are prudent and reasonable and that any costs for weather delays are minimized

Q. **Is FPL recovering these Project costs through any other mechanism?**

A. No.

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

A. Yes.

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

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.

Form 42-2P

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)	(48,018)	(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	66,000	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.

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)	(46,685)	(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	41,666	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	$ 3,058,273	$ 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	$ 1,512,641	$ 1,507,873	$ 1,760,949	$ 1,905,414	$ 10,238,746	$ 19,268,123			
4a Recoverable Costs Allocated to CP Demand	$ 875,551	$ 547,148	$ 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.

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.

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.

8

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.

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

Notes:

(A) N/A
(B) 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: 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.

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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: 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.

13

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.

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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: 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.

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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: 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.

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.

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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: 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.

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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: 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.

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 5.6640% 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: 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.

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.

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.

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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: 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.

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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: 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.

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.

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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: 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.

43

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.

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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: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.

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.

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.

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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: 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.

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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: 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.

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.

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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
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.

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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
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: **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 4^{th} 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 4^{th} 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

APPENDIX II

ENVIRONMENTAL COST RECOVERY

EXHIBITS OF
RANDALL R. LABAUVE

RRL-4	**NESHAP ICR Public Notice**
RRL-5	**Electric Utility Steam Generating Unit Hazardous Air Pollutant Information Collection Effort Burden Statement Part B**
RRL-6	**Florida Department of Environmental Protection (FDEP) Industrial Wastewater Facility Permit Number FL0001473 for Plant Cape Canaveral (PCC)**
RRL-7	**PCC Manatee Protection Plan (MPP)**
RRL-8	**U.S. Fish and Wildlife Service (USFWS) letter to FPL**
RRL-9	**Florida Fish and Wildlife Conservation Commission's (FWC) "FWC Staff Report For Florida Power and Light Company – Cape Canaveral Energy Center (CCEC)"**
RRL-10	**Manatee Heating System Conceptual Location of Pumps and Heater**

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: 2822T, 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 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.

<u>Coal-fired units, acid gas HAP</u>

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

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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

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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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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

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

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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	$35,657
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						$24,824,000
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 mangerial 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 faciliaty 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

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 AECW 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 (EP-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.

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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.

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

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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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 AECW
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.

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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.

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 AECW 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 AECW 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 AECW 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	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

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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 Builder Name	Monitoring Location Site 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.

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

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.

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. 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.

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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6000 North U.S. Highway 1		Expiration date:	August 9, 2010
Cocoa, FL 32927			

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 64E-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;

(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.]

PERMITTEE:

FP&L Cape Canaveral Plant
6000 North U.S. Highway 1
Cocoa, FL 32927

PERMIT NUMBER: FL0001473

Issuance date: August 10, 2005
Expiration date: August 9, 2010

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT OF
ENVIRONMENTAL PROTECTION

Mimi Drew

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 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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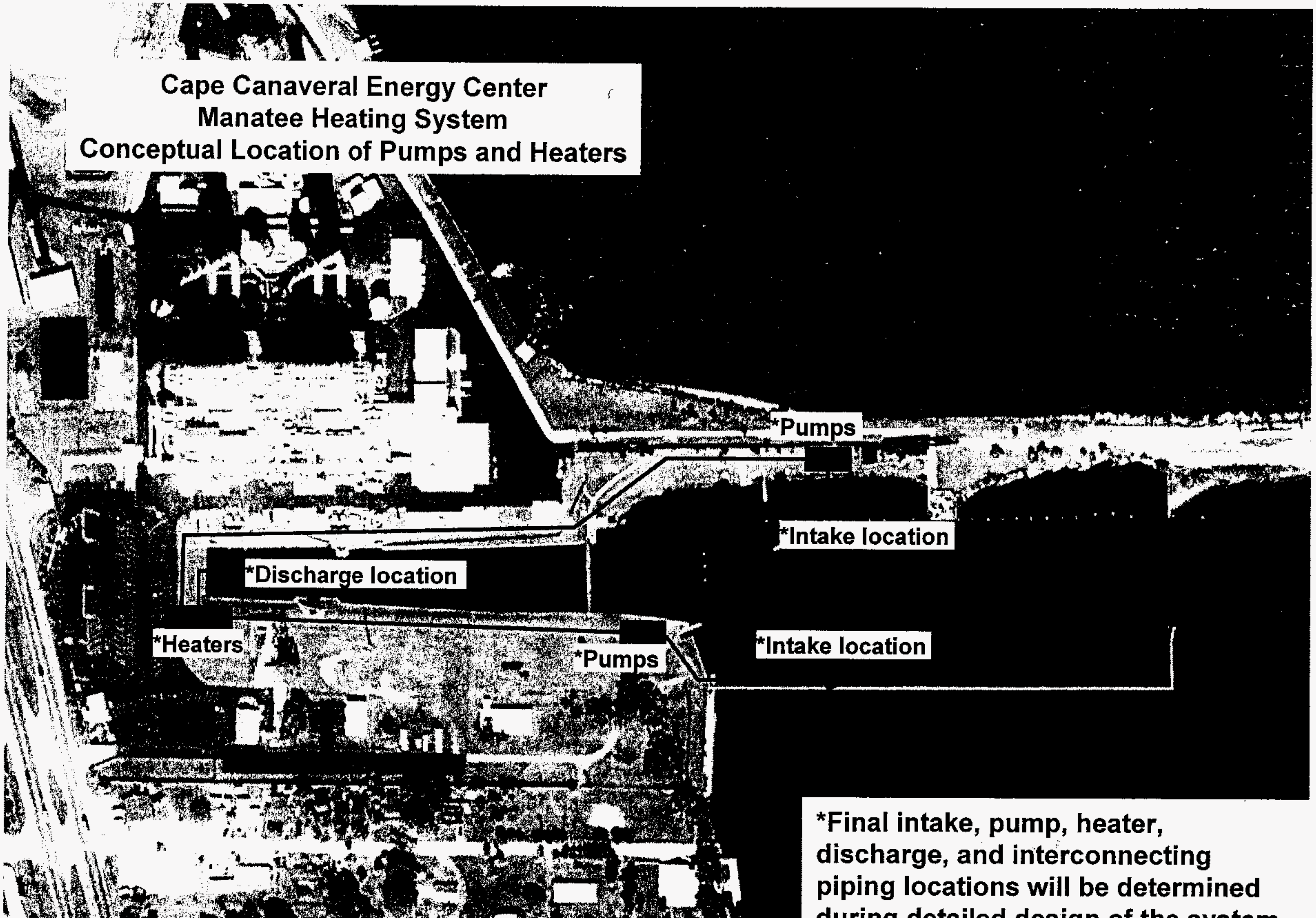

*Final intake, pump, heater, discharge, and interconnecting piping locations will be determined during detailed design of the system.