BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 070007-EI
FLORIDA POWER & LIGHT COMPANY

AUGUST 3, 2007

ENVIRONMENTAL COST RECOVERY

ESTIMATED/ACTUAL TRUE-UP
JANUARY 2007 THROUGH DECEMBER 2007

TESTIMONY & EXHIBITS OF:

K. M. DUBIN
R. R. LABAUVE

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

A. Yes, I have. My exhibit KMD-2 consists of eight forms, PSC Forms 42-1E through 42-8E, included in Appendix I. Form 42-1E provides a summary of the Estimated/Actual True-up amount for the period January 2007 through December 2007. Forms 42-2E and 42-3E reflect the calculation of the Estimated/Actual True-up amount for the period. Forms 42-4E and 42-6E reflect the Estimated/Actual O&M and Capital cost variances as compared to original projections for the period. Forms 42-5E and 42-7E reflect jurisdictional recoverable O&M and Capital project costs for the period. Form 42-8E (pages 1 through 43) reflects return on capital investments, depreciation, and taxes by project.

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

A. Forms 42-2E and 42-3E show the calculation of the ECRC Estimated/Actual True-up amount. The calculation for the Estimated/Actual True-up amount for the period January 2007 through December 2007 is an under-recovery, including interest, of $683,962 (Appendix I, Page 4, line 5 plus line 6). This Estimated/Actual True-up under-recovery of $683,962 consists of January through June 2007 actuals and revised estimates for July through December 2007, compared to original projections for the same period.

ORIGINAL

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 070007-EI

August 3, 2007

Q. Please state your name and address.

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

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

A. I am employed by Florida Power & Light Company (FPL) as Manager of Cost Recovery Clauses.

Q. Have you previously testified in this docket?

A. Yes, I have.

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

A. The purpose of my testimony is to present for Commission review and approval the Estimated/Actual True-up associated with FPL Environmental Compliance activities for the period January 2007 through December 2007.

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

A. Yes, with the exception of the Martin Plant Drinking Water System Compliance Project, which is discussed and supported in the testimony of Randall R. LaBauve, and the St. Lucie Cooling Water System Inspection and Maintenance Project, which is discussed and supported in FPL's petition filed with the Commission on January 8, 2007.

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

A. Form 42-4E (Appendix I, Page 7) shows that total O&M project costs were $5,491,607 (43.3%) higher than projected and Form 42-6E (Appendix I, Page 10) shows that total capital investment project costs were $4,472,647 (15.7%) lower than projected. Below are variance explanations for those O&M Projects and Capital Investment Projects with significant variances. Individual project variances are provided on Forms 42-4E and 42-6E. Return on Capital Investment, Depreciation and Taxes for each project for the Estimated/Actual period are provided as Form 42-8E (Appendix I, Pages 13 through 55).

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

Project expenditures are estimated to be $41,805 (1.9%) higher than previously projected. The variance is primarily due to the high demand in the tank repair market, which has increased the cost of labor.

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

Project expenditures are estimated to be $22,368 (8.3%) higher than previously projected. The variance is primarily due to greater than anticipated ash accumulation in the storage basins. As a result of the increase in ash material to be handled for removal, the site incurred extra expenses due to the use of additional moving equipment to support the job. Also, the time associated with the contractor completing the job contributed to the increases in manpower hours. This increase in time and materials to clean out ash accumulation ultimately resulted in increased expenditures.

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

Project expenditures are estimated to be $108,161 (138.4%) higher than projected. In the first and second quarter of 2007, additional transmission transformers requiring leak repairs or re-gasket work activities were discovered and scheduled to be worked during the remainder of 2007. The original projected work activities included one transmission transformer re-gaskets and a few leak repairs. The number increased to five transmission transformer re-gaskets and additional leak repairs.

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

The variance of $523,338 (109%) higher than projected is due to much higher than anticipated gains from the DOE sales of emissions allowances in 2007.

5. Pipeline Integrity Management – Distribution (Project No. 22) - O&M

Project expenditures are estimated to be $400,354 (47.7%) lower than projected. The variance is primarily due to lower than projected bids for cathodic protection work and the 30"pipeline inspection. Additionally, work was completed prior to the rainy season and costs associated with ground water issues, which were included in the original projections, were avoided.

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

Project expenditures are estimated to be $220,753 (237.4%) higher than projected. Additional required upgrades at the Sanford Plant, Martin Plant, Martin Terminal, Port Everglades Plant, Port Everglades Terminal, Manatee Plant, Manatee Terminal, Turkey Point Plans Units 1 and 2, and Cape Canaveral Plant were identified during development of the plan.

Additional engineering was required to develop conceptual designs and cost estimates for the upgrades, which are scheduled for implementation in 2008. These upgrades were not anticipated at the time FPL filed its original projections for 2007.

At Turkey Point Units 3 and 4, longer than estimated construction durations and the replacement of degraded gas tanks that did not pass Miami-Dade county inspections contributed to the variance. The original projections planned to utilize existing tanks. Once the work began it was discovered the tanks were degraded and needed to be replaced.

7. Manatee Reburn (Project No. 24) - O&M

Project expenditures are estimated to be $41,868 (8.4%) lower than projected. The variance is primarily due to limited maintenance time available during the May and June high load period.

8. Port Everglades Electrostatic Precipitator – ESP (Project No. 25) - O&M

Project expenditures are estimated to be $872,150 (41.4%) lower than projected. Fuel economics to date have dictated that the units at the Port Everglades Plant be run on gas because it is less expensive. Therefore, the ESPs have not had to be operated as much as was initially predicted for 2007, which reduced the equipment deterioration and generated significantly less ash for disposal.

9. Lowest Quality Water Source - LQWS (Project No. 27) – O&M

Project expenditures are estimated to be $161,771 (30.5%) lower than projected. The Wastewater Permit for the Cape Canaveral Plant was issued by the Florida Department of Environmental Protection (FDEP). However, there were delays due to water quality technical issues associated with the treatment systems and reclaimed water was not used at the plant; therefore, there was not a cost for the additional water treatment that would be required in order to use reclaimed water.

10. CWA 316(b) Phase II Rule (Project No. 28) – O&M

Project expenditures are estimated to be $1,018,188 (43.4%) lower than projected. This variance is primarily due to economies of scale achieved by the use of one contractor to perform the necessary work. Original estimates included the use of three contractors.

11. Selective Catalytic Reduction (SCR) Consumables (Project No. 29) – O&M

Project expenditures are estimated to be $34,685 (15.4%) higher than projected. The Manatee and Martin Plants are expected to operate at high capacity factors for the remaining months of the year thereby increasing the amount of consumables used. Additionally, catalyst sampling and testing expenses were higher than originally projected.

12. Hydrobiological Monitoring Plan (HBMP) (Project No. 30) –

O&M

Project expenditures are estimated to be $17,895 (71.6%) higher than projected. The variance is primarily due to additional monitoring required due to unexpected drought conditions. The permit requires that while we are on the Emergency Diversion Curves, we conduct additional river monitoring and submit a report.

13. CAIR Compliance Project (Project No. 31) – O&M

Project expenditures are estimated to be $156,047 (70.9%) higher than projected. This variance is due to costs associated with the 800 MW unit cycling study, which was not included in the original estimates for 2007. This study and its role in helping FPL cost-effectively comply with CAIR is discussed in the direct testimony of Mr. Randall R. LaBauve.

14. Best Available Retrofit Technology (BART) Project (Project No. 32) – O&M

Project expenditures are estimated to be $3,397, whereas FPL did not anticipate any 2007 expenditures for this project originally. The DEP requested additional information on FPL's BART Determination for Turkey Point Units 1 and 2, which necessitated the use of a contractor. This activity was not anticipated at the time FPL filed its original projections for 2007.

15. Continuous Emission Monitoring Systems - CEMS (Project

No. 3b) - Capital

The variance in depreciation and return is $60,189, or 5.5% lower than projected. This variance is primarily due to the procurement of a much lower cost per unit pricing from the vendor (California Analytical). In addition, several installations and in-service dates shifted from 2007 to 2008 due to equipment availability delays and schedule changes.

16. SO2 Allowances – Negative Return on Investment – Capital

The variance of $68,038, or 26.8% lower than projected is due to higher than anticipated gains amortization from the DOE sales of emissions allowances in 2007. This higher amortization resulted in a lower balance on which a return was calculated.

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

The variance in depreciation and return is $107,778, or 5.0% lower than projected. Previously planned diversionary structure work activities have been postponed, pending the completion of an assessment of existing diversionary structures. The Final Rule issued February 26, 2007 amending the existing SPCC Rule allows regulatory relief from containment requirements at facilities with oil-filled equipment by allowing an oil spill contingency planning option or active containment in addition to an inspection and monitoring program for oil-filled equipment in lieu of installing secondary containment or diversionary structures.

18. Clean Air Interstate Rule (CAIR) Compliance (Project No. 31) - Capital

The variance in the return on CWIP is estimated to be $2,742,160, or 63.9% lower than projected. This variance is primarily due to the Reburn and Low NOx Burner projects at Cape Canaveral Units 1 and 2, Port Everglades Units 3 and 4, and Turkey Point Units 1 and 2 being put on hold. This change in strategy is related to FPL's 800 MW unit cycling project and is discussed in Mr. LaBauve's direct testimony.

19. Clean Air Mercury Rule (CAMR) Compliance (Project No. 33) - Capital

The variance in the return on CWIP is estimated to be $1,254,563 or 78.7% lower than projected. Engineering and procurement activities associated with Scherer, which were projected for 2007, will now be performed in 2008.

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. 070007-EI

August 3, 2007

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 predecessors to this docket?

A. Yes, I have.

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

A. The purpose of my testimony is to present for the Commission's review and approval a new ECRC project, the Martin Plant Drinking Water System Compliance Project. Additionally, my testimony provides an update on FPL's approved Clean Air Interstate Rule (CAIR) Compliance and BART (CAVR) Projects, and discusses a new activity that will be required for FPL's approved St. Lucie Turtle Net Project.

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

A. Yes. Exhibits RRL-1 through RRL-8 listed below are included in Appendix II.

- Exhibit RRL-1 – Florida Department of Environmental Protection Rule 62-550.310, Florida Administrative Code – Primary Drinking Water Standards: Maximum Contaminant Levels and Maximum Residual Disinfectant Levels
- Exhibit RRL-2 – Consent Order in OGC Case Number 06-0744 FPL Martin Plant Public Water System PWS #4431748
- Exhibit RRL-3 – Golder Associates Inc. FPL Martin Plant Potable Water System DBP (THM & HAA5) Analysis
- Exhibit RRL-4 – Department of Environmental Protection – Letter approving Corrective Action Plan for FPL Martin Plant PWS #4431748
- Exhibit RRL-5 – Clean Air Interstate Rule – Summary of FPL 800 MW Unit Cycling Project
- Exhibit RRL-6 – Clean Air Interstate Rule – Summary of FPL Peaking Gas Turbine CEMS
- Exhibit RRL-7 – Clean Air Visibility Rule – Update Summary of FPL BART Project
- Exhibit RRL-8 – Clean Air Visibility Rule – Florida Department of Environmental Protection – Reasonable Progress Rule Workshop Slides

Martin Plant Drinking Water System Compliance Project

Q. Please describe the law or regulation requiring the Martin Plant Drinking Water System Compliance Project.

A. Florida Department of Environmental Protection (FDEP) Rule 62-550.310(3), Florida Administrative Code, imposed drinking water limits on Disinfectants and Disinfection Byproducts (DBPs) to implement the U.S. Environmental Protection Agency's (EPA's) Stage 1 Disinfection and Byproducts Rule, 40 CFR Parts 9, 141, and 142. A copy of Rule 62-550.310(3), F.A.C. is provided as Exhibit RRL-1 of Appendix II. The FDEP's Rule applies to community water systems (CWSs) and nontransient noncommunity water systems (NTNCWSs) that treat their water with a chemical disinfectant for either primary or residual treatment. Among other things, the FDEP Rule established maximum contaminant levels for four certain trihalomethanes (THMs) and haloacetic acids (HAA5s), which are DBPs.

FPL's Martin Plant is a NTNCWS subject to the FDEP Rule. FPL has tried unsuccessfully for several years to bring the drinking water system at the Martin Plant into compliance with the FDEP Rule. However, samples collected from the drinking water system on March 15, 2005, April 12, 2005, September 14, 2005, and December 28, 2005, were all found to be above the levels permitted for THMs and HAA5s. On September 22, 2006, FPL and the FDEP entered into a Consent Order to reach a settlement on the matter of the Martin Plant drinking water system's continuing non-compliance with the FDEP Rule. The Consent Order is provided as Exhibit RRL-2 of Appendix II.

Q. How is FPL complying with the requirements of the Consent Order?

A. Per the corrective actions specified in the Consent Order, FPL retained Golder Associates, Inc., which performed a site visit at the Martin Plant and inspected the drinking water system, reviewed well data, performed a literature search, and evaluated FPL's situation. Golder provided recommendations as to how to achieve compliance with the drinking water limits for THMs and HAA5s at the plant via a final report dated August 29, 2006. A copy of this final report is provided as Exhibit RRL-3 of Appendix II. In its final report, Golder concluded that the two DBP treatment technologies used in the drinking water system, which are aeration and activated carbon filtration, are at present the best technologies for the removal of DBPs and no additional treatment technology is necessary. Nonetheless, Golder concluded that the existing system at the Martin Plant would need corrective modifications in order to achieve the THM and HAA5 levels required per the FDEP and EPA Rules.

Q. What is FPL's corrective action plan and milestone dates?

A. On November 17, 2006, and pursuant to the Consent Order, FPL provided its final corrective action plan and milestone dates to the FDEP. FPL's corrective action plan and milestone dates are as follows:

- September 1, 2006 – FPL submits signed Consent Order and signed/sealed corrective action plan
- October 17, 2006 – FDEP issues written request for additional information (RFI)
- November 17, 2006 – FPL provides additional information to FDEP
- December 20, 2006 – FDEP issues written approval of the plan
- January 12, 2007 – FPL completes measurements of physical characteristics of aeration system, and takes synoptic samples of inlet and outlet water for both the aerator and the carbon filter, and sends those samples to the laboratory
- January 26, 2007 – FPL receives results/report from laboratory
- March 23, 2007 – Install pilot equipment for testing
- June 20, 2007 – Complete testing of pilot
- October 1, 2007 – FPL issues performance specifications to bidders to provide new aerator and carbon filter units
- November 1, 2007 – FPL receives bids to provide new aerator and carbon filter units
- December 1, 2007 – FPL awards contract to successful bidder to install new aerator and carbon filter units

- January 2008 – Installation of new aerator and carbon filter units is complete
- June 2008 – Testing of new aerator and carbon filter units is complete, FPL submits engineer's certification of completion of construction and required supporting documentation
- July 2008 – FDEP issues written clearance to place the system modifications into service

Q. What milestones has FPL completed to date?

A. FPL has completed the pilot testing on a small scale system to test the effectiveness of the proposed treatment process. FPL is awaiting the results of the testing. Once the results are received from the vendor, drawings detailing the necessary changes to the existing system will be obtained. These drawings will be used as part of the bid package to select the contractor for the installation of the final system. The next major milestone will be the issuance of the performance specifications to the bidders to provide new aerator and carbon filter units. The issuance of the performance specifications is scheduled to be completed on October 1, 2007.

Q. Why has FPL not submitted this Project for cost recovery through the ECRC previously?

A. At the time that the Martin Plant drinking water system became subject to the FDEP and EPA rules, FPL reasonably expected that the system would provide adequate water treatment to comply with the THM and HAA5 MCLs established by the rules. It was not until after the unsuccessful tests were performed in 2005, Golder completed its evaluation of the System in August 2006, and FPL negotiated the Consent Order with FDEP in September 2006 that FPL was aware that it would have to conduct the pilot test and implement modifications to the drinking water system required by the Consent Order.

Q. What activities is FPL asking to recover through the ECRC?

A. FPL is requesting to recover costs associated with implementing the treatment options resulting from the pilot test plan, that are found to be necessary to achieve compliance with the FDEP rule. The results of the pilot test plan will determine the most cost-effective and reliable treatment option to achieve compliance.

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

A. Following are FPL's preliminary capital estimates for potential treatment options:

- Addition of larger carbon bed - $40,000 - $60,000
- Addition of multimedia filter bed - $30,000 - $50,000
- Addition of high velocity stripper - $15,000 - $30,000

Additionally, annual O&M estimates for the removal and replacement of the exhausted carbon bed and multimedia filter bed (every 8 to 12 months) are $11,000 to $17,000 to begin in 2008.

Q. Does FPL expect to incur any Project costs in 2007?

A. Yes. FPL expects to incur $4,000 of Capital expenses associated with engineering and drawings detailing the changes to the existing system. These expenses are projected for October and November of 2007.

Q. Has FPL estimated how much will be spent on the Project in 2008?

A. Yes. FPL expects to incur $17,000 of O&M expenses and $140,000 of Capital expenses associated with the installation and maintenance of the new aerator and carbon bed.

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

A. The activities outlined in the preceding paragraphs represent a cost-effective strategy for complying with the Consent Order. FPL will utilize competitive bidding to procure the necessary services.

Q. Is FPL recovering the costs for the Martin Plant Drinking Water System Compliance Project through any other mechanism?

A. No.

CAIR Compliance Project Update

Q. What updates has FPL made to its CAIR Compliance Project?

A. There are two updates. The first relates to FPL's 800 MW Unit Cycling Project, which FPL believes will help it comply with CAIR more cost-effectively. The second update relates to FPL's determination that a more extensive Continuous Emissions Monitoring System (CEMS) Plan is needed for its gas turbine units.

Q. Please discuss FPL's 800 MW Unit Cycling plans.

A. FPL commissioned a study, with the Commission's approval, to evaluate emission reductions and necessary countermeasures to implement the 800 MW Unit Cycling project. Phase one and two of the 800 MW unit cycling study was completed in June of 2007. FPL has reviewed the results of the study and has concluded that implementation of the project on FPL's 800 MW fossil steam Electric Generating Units (EGUs) at the Martin and Manatee Plants would provide cost effective reductions in NOx emissions to help comply with CAIR. The study has identified several modifications that must be undertaken to allow the 800 MW units to cycle as needed without adversely affecting unit availability and reliability. Exhibit RRL-5 to this filing provides a summary of the 800 MW Unit Cycling Report, a discussion of the preliminary project scope to implement the 800 MW Unit Cycling project, a preliminary estimate of project costs, and the resultant projected emission reductions. Evaluation of detailed project cost schedules and implementation plan is currently underway following the determination that the project would provide highly cost effective emission reductions for CAIR compliance. I discussed this project in my October 13, 2006 testimony, but neither its cost nor its impact on the cost of other CAIR compliance projects was known at the time of FPL's 2007 ECRC projections.

As discussed in Exhibit RRL-5, FPL now expects to implement the 800 MW unit cycling project from 2007 through 2010 at its Manatee Units 1 & 2 and Martin Units 1 & 2, at an estimated capital cost of $97 million. Upon completion of the plan on all four 800 MW units, FPL projects an annual NOx reduction of 1,773 tons and an ozone season NOx reduction of 1,563 tons. As a result, FPL will not need to acquire as many additional allowances from the annual and ozone season NOx allowance markets for compliance with CAIR. FPL has provided a detailed description and implementation plan for the 800 MW Unit Cycling Project in Exhibit RRL-5. This exhibit also provides a discussion of FPL's selection of the project for compliance with CAIR.

Q. **Has FPL identified potential changes to its CAIR compliance plan that could affect the decision to proceed on implementation of the 800 MW Unit Cycling Project on all of the project units?**

A. Yes. On July 13, 2007, Florida Governor Charlie Crist signed three executive orders initiating climate change requirements for Florida.

Executive Order 07-127 requires the FDEP to initiate rulemaking to reduce CO_2 emissions from electricity production to year 2000 levels by 2017, year 1990 levels by 2025, and to a level 80% below the 1990 levels by 2050. The goals established in Executive Order 07-127 may require significant CO_2 emissions reductions from existing fossil power plants, which may impact FPL's decision to fully implement the 800 MW Unit Cycling Project. FPL is currently participating in the FDEP rulemaking and we will be evaluating strategies that may be required to meet the compliance requirements of the new rule. FPL's implementation of the 800 MW Unit Cycling Project, and any other NOx or SO_2 reduction project to comply with the CAIR requirements, will be evaluated to ensure that projects will provide the most cost effective overall compliance strategy to meet all new environmental requirements.

Q. Please discuss the changes FPL has made to its CEMS plans for gas turbine units and why these changes are necessary to comply with CAIR.

A. FPL has recently identified the need to change the CEMS Plan for the small peaking gas turbine units and to implement a Gas Turbine CEMS CAIR Compliance strategy within the CAIR Compliance Project. CAIR requires that generating unit emissions from all CAIR affected sources monitor NOx and SO_2 emissions through implementation of CEMS that comply with the applicable federal emission monitoring requirements under 40 CFR Part 75. FPL's fossil generation is compliant with these requirements of Part 75 through the CEMS, which had been installed to comply with Acid Rain requirements, with the exception of the small combustion turbine peaking units located at the Lauderdale, Port Everglades and Ft. Myers plants. FPL's gas turbine peaking units were not subject to Acid Rain monitoring requirements and historically have not had CEMS.

Initially, FPL planned to comply with the CEMS monitoring requirements for these peaking units through use of Low Mass Emission (LME) default emission rate requirements under Part 75, which require only limited emission monitoring system requirements. Subsequent reviews of FPL's compliance strategy for CAIR identified an increased compliance risk and potential increases in monitoring system costs if FPL adopts the default emission rate monitoring requirements. FPL now proposes to implement LME "Identical Units" Part 75 CEMS requirements, which provide for monitoring of representative units for groups of similar generating units. FPL proposes to implement the revised monitoring plan for the peaking gas turbines at an estimated cost of $396,273 as the least cost alternative for compliance with this part of the CAIR requirements. Exhibit RRL-6 to this filing provides a discussion of the LME monitoring options under 40 CFR Part 75.19, a description of "Similar Units" CEMS option implementation as the preferred compliance method, and the preliminary cost projections for implementation.

Q. What is the status of FPL's legal challenge to CAIR?

A. On December 23, 2007, the Administrative Law Judge (ALJ) ruled against FPL's challenge in the Division of Administrative Hearings of the FDEP's implementation rules for CAIR. FPL appealed the ALJ's decision in the 3rd Circuit Court of Appeals. FPL filed its initial brief on June 8, 2007, the FDEP filed its answer brief on July 16, 2007, and FPL will file its reply brief by August 15, 2007. FPL is also continuing its challenge to EPA's CAIR through an appeal filed in the DC Circuit Court. Initial briefs were filed on March 5, 2007 and final briefs are due September 5, 2007. There is no formal timetable for decisions on CAIR challenges, but FPL anticipates that the state and federal appellate courts will decide late this year or in the first half of 2008.

BART Project Update

Q. What updates has FPL made to its BART Project?

A. There are two updates to FPL's BART Project, which recovers costs associated with the Regional Haze Rule – Best Available Retrofit Technology (BART), now referred to as the Clean Air Visibility Rule (CAVR). The first relates to the current status of FPL's BART Project. The second relates to the determination that the FDEP's requirement for Reasonable Further Progress towards meeting the visibility goals established in Section 169A of the Clean Air Act will require additional analyses to identify generating units within FPL's system that may require additional compliance measures.

Q. Please explain the purpose of your testimony as it relates to the BART Project.

A. In Order No. PSC-05-1251-FOF-EI, the Commission found that the costs associated with complying with the Clean Air Visibility Rule (CAVR) requirements through the BART Project are eligible for recovery through the ECRC, subject to the demonstration that costs for specific activities are reasonable and prudent. To comply with the requirements of the CAVR, FPL evaluated the impacts of generating units affected by the BART requirements to reduce regional haze.

In testimony submitted to the Commission on the BART Project in Docket No. 050007-EI, and approved in Order No. PSC-05-1251-FOF-EI, FPL identified compliance options for FPL units meeting the CAVR requirements. The following issues were addressed as part of the CAVR:

- The available retrofit control options
- Existing pollution control equipment in use at the facility
- Compliance costs associated with each available control option
- The remaining useful life of the unit
- The energy and non-air impacts associated with implementing a control option
- The control options impact on visibility (as determined

through modeling)

The evaluation required FPL to have detailed visibility modeling performed to determine the impacts on Federal Class 1 areas (National Parks and Wildlife Areas). Affected units, which are determined to adversely impact Class 1 areas and meet the CAVR technology requirements, will be required to reduce emissions. FPL has now completed the required visibility modeling at a total cost of $26,203. A summary of the results of this study has been included in Exhibit RRL-7. Screening analyses performed to evaluate CAVR applicability identified that most of FPL's BART eligible units were exempt from CAVR control requirements. FPL's Turkey Point Fossil Units 1 & 2 did not pass the screening analysis and were subject to the more detailed determination required by the rule. FPL provided the CAVR determination for Particulate Matter impacts from Turkey Point Fossil Units 1 & 2 to the Florida FDEP on January 31, 2007.

Q. Please discuss FDEP's proposed Reasonable Progress rulemaking.

A. On May 25, 2007 the FDEP published a Notice of Proposed Rulemaking to adopt Rule 62-296.341, "Regional Haze – Reasonable Progress," which would implement the Reasonable Progress portion of CAVR.

The CAVR requires states to achieve "natural background" visibility in Class 1 areas by 2064. The Reasonable Progress portion of CAVR requires that a "glide path" be established for each Class 1 area, which is effectively the slope from the baseline visibility to the calculated natural background visibility that must be reached by the year 2064. Periodic points along the "glide path" then become "Reasonable Progress" goals to help assure that the natural background visibility deadline is met. States are required to submit State Implementation Plans which demonstrate that the Reasonable Progress goals will be met through achieving visibility improvements periodically along the "glide path". The FDEP held a workshop on its proposed "Reasonable Progress" rule on June 14, 2007. Materials from that workshop have been included in Exhibit RRL-8.

In support of the Reasonable Progress requirements of CAVR, the FDEP performed a screening analysis to identify potential applicable sources and made available those results. FDEP has initially identified 12 of FPL's oil-burning units as Proposed Sources subject to the Reasonable Progress Four-Factor analysis. Under the proposed rule, FPL's sources will have to undergo an evaluation against those four factors to select the appropriate control technology to reduce impacts to Class 1 areas. Units which have been identified as affected units under the Four-Factor test would be required to implement Reasonable Progress Control Technology (RPCT) under the FDEP's proposed rule.

Exhibit RRL-8 provides a detailed description of the EPA guidance on the Four-Factor test. To determine whether FPL's oil burning units will be affected by the proposed rule, FPL plans to engage a consultant to prepare the required four-factor analyses. FPL has projected a year 2007 project cost of $25,000 in O&M costs for the required analyses.

Results from the FDEP screening study for Reasonable Progress indicated that Turkey Point Fossil Units 1 & 2, Port Everglades Units 1 – 4, Riviera Units 3 & 4, Martin Units 1 & 2, and Manatee Units 1 & 2 have potential adverse impacts to Class 1 Areas within Florida. Results from the required Four-Factor analysis will be used to identify FPL fossil steam generating unit emission reduction requirements under the Reasonable Progress rule. FPL anticipates that some additional reductions in emissions of SO_2 and Particulate Matter from FPL EGUs may be required to achieve the Reasonable Progress goals for Florida Class 1 areas. Once the FDEP Reasonable Progress Rule has been finalized, FPL will be required to submit a plan to achieve the Reasonable Progress goals. FPL anticipates that a detailed engineering study to identify the least cost compliance options for Reasonable Progress will be required to develop its compliance plan which is due to the FDEP by January 31, 2008.

St. Lucie Turtle Net Project – New Activity

Q. Please briefly describe FPL's currently approved St. Lucie Turtle Net Project.

A. FPL's current St. Lucie Turtle Net Project was approved by the

Commission in Order PSC-02-1421-PAA-EI, issued on October 17, 2002. The Project included the replacement and enhancement of an existing mesh net system that was located across the intake canal at the St. Lucie Plant to prevent several species of endangered sea turtles from being drawn into the cooling water inlets on the generating units. The existing net system had become deformed to the point that it could trap turtles when large influxes of seaweed and jellyfish entered the intake canal. The net replacement and enhancement of the net system was performed in 2002.

Q. What new activities is FPL now having to undertake pursuant to the St. Lucie Turtle Net Project?

A. The antifoulant and protective coating on the existing 5-inch net located at the intake canal at the St. Lucie Plant has deteriorated, permitting marine growth to adhere to the net material. The net has also experienced UV damage. Because of this determination, the net must be replaced.

The existing deteriorated 5-inch net will be removed and sent back to the manufacturer to be re-coated. FPL will purchase and install a new 5-inch barrier net, and the re-coated original net will be stored on-site as a back-up.

Q. Why didn't FPL include costs for a net replacement in its original filing in 2002?

A. FPL's petition for recovery of the St. Lucie Turtle Net Project was filed on June 18, 2002. At the time the petition was filed, FPL had not yet selected the manufacturer of the net. When the manufacturer and net material were chosen, it was determined that a protective coating would be required in order to maintain the integrity of the net. Per the manufacturer, the protective coating had a five-year life expectancy, information that was not known at the time of the original filing.

Q. How will FPL ensure that the costs incurred for re-coating the current net and the purchase of the net are prudent and reasonable?

A. The project scope will be awarded based on competitive bid. Qualified bidders will be selected to bid on the project. The lowest bid that meets the specification requirements will be awarded the contract. Project implementation will be supervised by FPL.

Q. When does FPL expect to incur costs for the new activity associated with the St. Lucie Turtle Net Project?

A. FPL expects to purchase the new 5-inch net in the last quarter of 2007. The current net will be sent to the manufacturer for re-coating during the first quarter of 2008 at which time the new net will be installed.

Q. What is FPL's estimated cost for the new activities associated with the St. Lucie Turtle Net Project?

A. The estimated capital cost for the new 5-inch net is $288,000, to be incurred in the last quarter of 2007. The estimated O&M cost associated with re-coating the existing net is $10,000, to be incurred in the first quarter of 2008.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX I

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

JANUARY 2007 – DECEMBER 2007
ESTIMATED/ACTUAL TRUE-UP

KMD-2
DOCKET NO. 070007-EI
FPL WITNESS: K.M. DUBIN
EXHIBIT ______
PAGES 1-52

Form 42-1E

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up
for the Period January through December 2007

Line No.		
1	Over/(Under) Recovery for the Current Period (Form 42-2E, Page 2 of 2, Line 5)	($1,282,604)
2	Interest Provision (Form 42-2E, Page 2 of 2, Line 6)	$598,642
3	Sum of Current Period Adjustments (Form 42-2E, Page 2 of 2, Line 10)	$0
4	Estimated/Actual True-up to be refunded/(recovered) in January through December 2008	($683,962)

( ) Reflects Underrecovery

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up Amount for the Period
January through December 2007

Line No.		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June
1	ECRC Revenues (net of Revenue Taxes)	$1,983,736	$1,707,980	$1,689,491	$1,713,020	$1,891,211	$2,088,038
2	True-up Provision (Order No. PSC-06-0972-FOF-EI)	1,337,720	1,337,720	1,337,720	1,337,720	1,337,720	1,337,720
3	ECRC Revenues Applicable to Period (Lines 1 + 2)	3,321,456	3,045,700	3,027,211	3,050,739	3,228,931	3,425,758
4	Jurisdictional ECRC Costs						
	a - O&M Activities (Form 42-5E, Line 9)	566,436	598,119	1,725,067	1,037,492	621,715	1,666,686
	b - Capital Investment Projects (Form 42-7E, Line 9)	1,629,758	1,759,288	1,787,917	1,814,741	1,861,056	1,964,793
	c - Total Jurisdictional ECRC Costs	2,196,194	2,357,407	3,512,984	2,852,233	2,482,771	3,631,479
5	Over/(Under) Recovery (Line 3 - Line 4c)	1,125,262	688,293	(485,773)	198,506	746,160	(205,721)
6	Interest Provision (Form 42-3E, Line 10)	76,826	75,201	70,111	63,925	60,412	56,104
7	Prior Periods True-Up to be (Collected)/Refunded in 2007	16,052,637	15,917,005	15,342,779	13,589,397	12,514,109	11,982,961
	a - Deferred True-Up from 2006 (Form 42-1A, Line 7)	1,563,849	1,563,849	1,563,849	1,563,849	1,563,849	1,563,849
8	True-Up Collected /(Refunded) (See Line 2)	(1,337,720)	(1,337,720)	(1,337,720)	(1,337,720)	(1,337,720)	(1,337,720)
9	End of Period True-Up (Lines 5+6+7+7a+8)	17,480,854	16,906,628	15,153,246	14,077,958	13,546,810	12,059,473
10	Adjustments to Period Total True-Up Including Interest						
11	End of Period Total Net True-Up (Lines 9+10)	$17,480,854	$16,906,628	$15,153,246	$14,077,958	$13,546,810	$12,059,473

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up Amount for the Period
January through December 2007

Line No.		Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	ECRC Revenues (net of Revenue Taxes)	$2,360,856	$2,374,903	$2,360,601	$2,216,793	$1,979,023	$1,994,994	$24,360,645
2	True-up Provision (Order No. PSC-06-0972-FOF-EI)	1,337,720	1,337,720	1,337,720	1,337,720	1,337,720	1,337,720	16,052,637
3	ECRC Revenues Applicable to Period (Lines 1 + 2)	3,698,576	3,712,622	3,698,320	3,554,512	3,316,742	3,332,713	40,413,282
4	Jurisdictional ECRC Costs							
	a - O&M Activities (Form 42-5E, Line 9)	1,435,857	1,427,308	1,966,801	2,431,111	2,162,843	2,290,581	17,930,015
	b - Capital Investment Projects (Form 42-7E, Line 9)	2,060,532	2,101,978	2,145,794	2,184,491	2,212,438	2,243,085	23,765,871
	c - Total Jurisdictional ECRC Costs	3,496,389	3,529,286	4,112,595	4,615,602	4,375,281	4,533,666	41,695,886
5	Over/(Under) Recovery (Line 3 - Line 4c)	202,187	183,336	(414,275)	(1,061,090)	(1,058,539)	(1,200,953)	(1,282,604)
6	Interest Provision (Form 42-3E, Line 10)	50,564	45,748	39,555	30,598	20,183	9,415	598,642
7	Prior Periods True-Up to be (Collected)/Refunded in 2007	10,495,624	9,410,655	8,302,020	6,589,581	4,221,370	1,845,295	16,052,637
	a - Deferred True-Up from 2006 (Form 42-1A, Line 7)	1,563,849	1,563,849	1,563,849	1,563,849	1,563,849	1,563,849	1,563,849
8	True-Up Collected /(Refunded) (See Line 2)	(1,337,720)	(1,337,720)	(1,337,720)	(1,337,720)	(1,337,720)	(1,337,720)	(16,052,637)
9	End of Period True-Up (Lines 5+6+7+7a+8)	10,974,504	9,865,869	8,153,430	5,785,219	3,409,144	879,887	879,887
10	Adjustments to Period Total True-Up Including Interest							
11	End of Period Total Net True-Up (Lines 9+10)	$10,974,504	$9,865,869	$8,153,430	$5,785,219	$3,409,144	$879,887	$879,887

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up Amount for the Period
January through December 2007

Interest Provision (in Dollars)

Line No.		January	February	March	April	May	June
1	Beginning True-Up Amount (Form 42-2A, Lines 7 + 7a + 10)	$17,616,486	$17,480,854	$16,906,628	$15,153,246	$14,077,958	$13,546,810
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	17,404,028	16,831,427	15,083,135	14,014,033	13,486,398	12,003,369
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	$35,020,514	$34,312,281	$31,989,763	$29,167,279	$27,564,356	$25,550,179
4	Average True-Up Amount (Line 3 x 1/2)	$17,510,257	$17,156,141	$15,994,882	$14,583,640	$13,782,178	$12,775,090
5	Interest Rate (First Day of Reporting Month)	5.27000%	5.26000%	5.26000%	5.26000%	5.26000%	5.26000%
6	Interest Rate (First Day of Subsequent Month)	5.26000%	5.26000%	5.26000%	5.26000%	5.26000%	5.28000%
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	10.53000%	10.52000%	10.52000%	10.52000%	10.52000%	10.54000%
8	Average Interest Rate (Line 7 x 1/2)	5.26500%	5.26000%	5.26000%	5.26000%	5.26000%	5.27000%
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.43875%	0.43833%	0.43833%	0.43833%	0.43833%	0.43917%
10	Interest Provision for the Month (Line 4 x Line 9)	$76,826	$75,201	$70,111	$63,925	$60,412	$56,104

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-up Amount for the Period
January through December 2007

Interest Provision (in Dollars)

Line No.		July	August	September	October	November	December	End of Period Amount
1	Beginning True-Up Amount (Form 42-2A, Lines 7 + 7a + 10)	$12,059,473	$10,974,504	$9,865,869	$8,153,430	$5,785,219	$3,409,144	$145,029,621
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	10,923,940	9,820,121	8,113,875	5,754,621	3,388,961	870,472	127,694,380
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	$22,983,413	$20,794,625	$17,979,744	$13,908,051	$9,174,180	$4,279,616	$272,724,001
4	Average True-Up Amount (Line 3 x 1/2)	$11,491,707	$10,397,313	$8,989,872	$6,954,026	$4,587,090	$2,139,808	$136,362,001
5	Interest Rate (First Day of Reporting Month)	5.28000%	5.28000%	5.28000%	5.28000%	5.28000%	5.28000%	N/A
6	Interest Rate (First Day of Subsequent Month)	5.28000%	5.28000%	5.28000%	5.28000%	5.28000%	5.28000%	N/A
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	10.56000%	10.56000%	10.56000%	10.56000%	10.56000%	10.56000%	N/A
8	Average Interest Rate (Line 7 x 1/2)	5.28000%	5.28000%	5.28000%	5.28000%	5.28000%	5.28000%	N/A
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.44000%	0.44000%	0.44000%	0.44000%	0.44000%	0.44000%	N/A
10	Interest Provision for the Month (Line 4 x Line 9)	$50,564	$45,748	$39,555	$30,598	$20,183	$9,415	$598,642

Form 42-4E

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-Up Amount for the Period
January 2007 - December 2007

Variance Report of O&M Activities
(in Dollars)

Line		(1) Estimated Actual	(2) Original Projections	(3) Variance Amount	(4) Variance Percent
1	Description of O&M Activities				
	1 Air Operating Permit Fees-O&M	$1,822,006	$1,951,100	($129,094)	-6.6%
	3a Continuous Emission Monitoring Systems-O&M	$685,667	$749,284	($63,617)	-8.5%
	5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	$2,239,772	$2,197,967	$41,805	1.9%
	8a Oil Spill Cleanup/Response Equipment-O&M	$211,821	$212,004	($183)	-0.1%
	13 RCRA Corrective Action-O&M	$103,706	$100,000	$3,706	3.7%
	14 NPDES Permit Fees-O&M	$124,400	$124,900	($500)	-0.4%
	17a Disposal of Noncontainerized Liquid Waste-O&M	$291,368	$269,000	$22,368	8.3%
	19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	$1,152,314	$1,147,220	$5,094	0.4%
	19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	$186,311	$78,150	$108,161	138.4%
	19c Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	($560,232)	($560,232)	$0	0.0%
	20 Wastewater Discharge Elimination & Reuse	$0	$0	$0	0.0%
	NA Amortization of Gains on Sales of Emissions Allowances	($1,003,674)	($480,336)	($523,338)	109.0%
	21 St. Lucie Turtle Net	$0	$0	$0	0.0%
	22 Pipeline Integrity Management	$438,646	$839,000	($400,354)	-47.7%
	23 SPCC-Spill Prevention, Control & Countermeasures	$313,753	$93,000	$220,753	237.4%
	24 Manatee Reburn	$458,132	$500,000	($41,868)	-8.4%
	25 Port Everglades ESP	$1,232,950	$2,105,100	($872,150)	-41.4%
	26 UST Replacement/Removal	$6	$0	$6	100.0%
	27 Lowest Quality Water Source	$368,233	$530,004	($161,771)	-30.5%
	28 CWA 316(b) Phase II Rule	$1,325,259	$2,343,447	($1,018,188)	-43.4%
	29 SCR Consumables	$259,889	$225,204	$34,685	15.4%
	30 HBMP	$42,891	$24,996	$17,895	71.6%
	31 CAIR Compliance	$376,055	$220,008	$156,047	70.9%
	32 BART	$3,397	$0	$3,397	100.0%
	33 St. Lucie Cooling Water System Inspection & Maintenance	$8,088,753	$0	$8,088,753	100.0%
2	Total O&M Activities	$18,161,423	$12,669,816	$5,491,607	43.3%
3	Recoverable Costs Allocated to Energy	$4,330,396	$5,735,829	($1,405,433)	-24.5%
4a	Recoverable Costs Allocated to CP Demand	$12,958,829	$6,066,883	$6,891,946	113.6%
4b	Recoverable Costs Allocated to GCP Demand	$872,198	$867,104	$5,094	0.6%

Notes:
Column(1) is the 12-Month Totals on Form 42-5E
Column(2) is the approved projected amount in accordance with
FPSC Order No. PSC-06-0972-FOF-EI
Column(3) = Column(1) - Column(2)
Column(4) = Column(3) / Column(2)

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/actual True-up Amount for the Period
January 2007 - December 2007

O&M Activities
(In Dollars)

Line #	Project #	Actual JAN	Actual FEB	Actual MAR	Actual APR	Actual MAY	Actual JUN	6-Month Sub-Total
1	Description of O&M Activities							
	1 Air Operating Permit Fees-O&M	166,075	18,529	165,175	153,827	165,175	165,175	833,956
	3a Continuous Emission Monitoring Systems-O&M	163,176	40,359	35,896	32,003	25,644	166,212	463,290
	5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	9,206	-7,914	1,311	7,249	27,965	365,710	403,527
	8a Oil Spill Cleanup/Response Equipment-O&M	17,555	13,168	13,401	37,789	13,510	5,498	100,921
	13 RCRA Corrective Action-O&M	0	12,483	6,363	0	0	0	18,846
	14 NPDES Permit Fees-O&M	124,400	0	0	0	0	0	124,400
	17a Disposal of Noncontainerized Liquid Waste-O&M	24,972	37,314	38,486	0	61,779	40,017	202,568
	19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	69,251	141,375	108,258	69,302	93,380	67,431	548,997
	19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	0	47,846	1,310	6,034	0	6	55,196
	19c Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	-46,686	-46,686	-46,686	-46,686	-46,686	-46,686	-280,116
	20 Wastewater Discharge Elimination &Reuse	0	0	0	0	0	0	0
	NA Amortization of Gains on Sales of Emissions Allowances	-11,584	-11,584	-11,584	-11,584	-328,710	-89,804	-464,850
	21 St. Lucie Turtle Net	0	0	0	0	0	0	0
	22 Pipeline Integrity Management	0	4,376	2,086	100,379	10,410	123,200	240,451
	23 SPCC - Spill Prevention, Control & Countermeasures	-6,847	9,790	10,915	31,425	87,884	22,687	155,854
	24 Manatee Reburn	31,615	13,440	77,504	38,268	-318	1,623	162,132
	25 Pt. Everglades ESP Technology	29,593	39,645	48,766	45,566	60,373	93,967	317,910
	26 UST Replacement/Removal	-5,504	5,510	0	0	0	0	6
	27 Lowest Quality Water Source	-840	0	39,064	0	22,911	62,816	123,951
	28 CWA 316(b) Phase II Rule	1,351	92,552	156,252	29,782	127,944	209,687	617,568
	29 SCR Consumables	6,805	4,260	26,029	8,456	27,653	44,389	117,592
	30 HBMP	1,504	2,831	5,483	2,229	2,229	1,415	15,691
	31 CAIR Compliance	-10,622	88,727	128,928	22,650	20,417	28,455	278,555
	32 BART	0	0	0	1,797	1,600	0	3,397
	34 St. Lucie Cooling Water System Inspection & Maintenance	10,351	98,730	940,461	522,530	255,948	426,940	2,254,960
	35 Martin Plant Drinking Water System Compliance	0	0	0	0	0	0	0
2	Total of O&M Activities	$ 573,771	$ 604,751	$ 1,747,418	$ 1,051,016	$ 629,108	$ 1,688,738	$ 6,294,802
3	Recoverable Costs Allocated to Energy	$ 415,789	$ 245,743	$ 520,906	$ 327,441	$ 45,327	$ 453,737	$ 2,008,943
4a	Recoverable Costs Allocated to CP Demand	$ 112,074	$ 240,976	$ 1,141,597	$ 677,616	$ 513,744	$ 1,190,913	$ 3,876,920
4b	Recoverable Costs Allocated to GCP Demand	$ 45,908	$ 118,032	$ 84,915	$ 45,959	$ 70,037	$ 44,088	$ 408,939
5	Retail Energy Jurisdictional Factor	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%	
6a	Retail CP Demand Jurisdictional Factor	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%	
6b	Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	
7	Jurisdictional Energy Recoverable Costs (A)	$ 409,928	$ 242,279	$ 513,563	$ 322,825	$ 44,688	$ 447,341	$ 1,980,624
8a	Jurisdictional CP Demand Recoverable Costs (B)	$ 110,600	$ 237,808	$ 1,126,589	$ 668,708	$ 506,990	$ 1,175,257	$ 3,825,952
8b	Jurisdictional GCP Demand Recoverable Costs (C)	$ 45,908	$ 118,032	$ 84,915	$ 45,959	$ 70,037	$ 44,088	$ 408,939
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 566,436	$ 598,119	$ 1,725,067	$ 1,037,492	$ 621,715	$ 1,666,686	$ 6,215,515

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

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/actual True-up Amount for the Period
January 2007 - December 2007

O&M Activities
(In Dollars)

Line # Project #	Estimated JUL	Estimated AUG	Estimated SEP	Estimated OCT	Estimated NOV	Estimated DEC	6-Month Sub-Total	12-Month Total	Method of Classification CP Demand	GCP Demand	Energy
1 Description of O&M Activities											
1 Air Operating Permit Fees-O&M	164,675	164,675	164,675	164,675	164,675	164,675	988,050	1,822,006			$1,822,006
3a Continuous Emission Monitoring Systems-O&M	36,238	36,754	35,751	39,850	36,306	37,478	222,377	685,667			685,667
5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	760,427	542,500	225,000	100,000	100,000	108,318	1,836,245	2,239,772	2,239,772		
8a Oil Spill Cleanup/Response Equipment-O&M	15,150	25,150	15,150	15,150	25,150	15,150	110,900	211,821			211,821
13 RCRA Corrective Action-O&M	15,000	0	30,000	0	25,000	14,860	84,860	103,706	103,706		
14 NPDES Permit Fees-O&M							0	124,400	124,400		
17a Disposal of Noncontainerized Liquid Waste-O&M	22,800	10,000	23,000	33,000	0	0	88,800	291,368			291,368
19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	121,810	135,540	74,370	120,560	112,100	38,937	603,317	1,152,314		1,152,314	
19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	26,857	0	32,258	0	70,000	0	131,115	186,311	171,979		14,332
19c Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	-46,686	-46,686	-46,686	-46,686	-46,686	-46,686	-280,116	-560,232	(258,569)	(280,116)	(21,547)
20 Wastewater Discharge Elimination & Reuse	0	0	0	0	0	0	0	0	0		
NA Amortization of Gains on Sales of Emissions Allowances	-89,804	-89,804	-89,804	-89,804	-89,804	-89,804	-538,824	-1,003,674			(1,003,674)
21 St. Lucie Turtle Net	0	0	0	0	0	0	0	0	0		
22 Pipeline Integrity Management	22,115	176,080	0	0	0	0	198,195	438,646	438,646		
23 SPCC - Spill Prevention, Control & Countermeasures	39,500	39,500	42,899	12,000	12,000	12,000	157,899	313,753	313,753		
24 Manatee Reburn	31,000	41,000	41,000	61,000	61,000	61,000	296,000	458,132			458,132
25 Pt. Everglades ESP Technology	95,784	110,784	101,562	435,682	76,032	95,196	915,040	1,232,950			1,232,950
26 UST Replacement/Removal							0	6	6		
27 Lowest Quality Water Source	24,583	24,583	24,583	24,583	24,583	121,367	244,282	368,233	368,233		
28 CWA 316(b) Phase II Rule	133,243	77,847	86,410	101,616	85,930	222,645	707,691	1,325,259	1,325,259		
29 SCR Consumables	23,542	37,292	23,524	17,292	23,542	17,105	142,297	259,889			259,889
30 HBMP	1,700	6,700	1,700	1,700	13,700	1,700	27,200	42,891	42,891		
31 CAIR Compliance	16,250	16,250	16,250	16,250	16,250	16,250	97,500	376,055			376,055
32 BART	0	0	0	0	0	0	0	3,397			3,397
34 St. Lucie Cooling Water System Inspection & Maintenance	37,793	137,000	1,191,000	1,458,000	1,481,000	1,531,000	5,833,793	8,088,753	8,088,753		
35 Martin Plant Drinking Water System Compliance	0	0	0	0	0	0	0	0	0		
2 Total of O&M Activities	$1,453,977	$1,445,165	$1,992,642	$2,462,868	$2,190,778	$2,321,191	$11,866,621	$18,161,423	$ 12,958,829	$ 872,198	$ 4,330,396
3 Recoverable Costs Allocated to Energy	$ 316,059	$ 350,305	$ 331,794	$ 691,299	$ 316,740	$ 315,254	$ 2,321,452	$ 4,330,396			
4a Recoverable Costs Allocated to CP Demand	$1,039,451	$ 982,663	$1,609,821	$1,674,352	$1,785,281	$1,990,343	$ 9,081,910	$12,958,829			
4b Recoverable Costs Allocated to GCP Demand	$ 98,467	$ 112,197	$ 51,027	$ 97,217	$ 88,757	$ 15,594	$ 463,259	$ 872,198			
5 Retail Energy Jurisdictional Factor	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%					
6a Retail CP Demand Jurisdictional Factor	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%					
6b Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%					
7 Jurisdictional Energy Recoverable Costs (A)	$ 311,604	$ 345,367	$ 327,116	$ 681,554	$ 312,275	$ 310,810	$ 2,288,726	$ 4,269,350			
8a Jurisdictional CP Demand Recoverable Costs (B)	$1,025,786	$ 969,744	$1,588,658	$1,652,340	$1,761,811	$1,964,177	$ 8,962,516	$12,788,468			
8b Jurisdictional GCP Demand Recoverable Costs (C)	$ 98,467	$ 112,197	$ 51,027	$ 97,217	$ 88,757	$ 15,594	$ 463,259	$ 872,198			
9 Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,435,857	$1,427,308	$1,966,801	$2,431,111	$2,162,843	$2,290,581	$11,714,501	$17,930,016			

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

Totals may not add due to rounding.

Form 42-6E

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/Actual True-Up Amount for the Period
January 2007 - December 2007

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

Line		(1) Estimated Actual	(2) Original Projections	(3) Variance Amount	(4) Variance Percent
1	Description of Investment Projects				
2	Low NOx Burner Technology-Capital	$ 908,197	$ 931,745	$ (23,548)	-2.5%
3b	Continuous Emission Monitoring Systems-Capital	1,025,600	1,085,789	(60,189)	-5.5%
4b	Clean Closure Equivalency-Capital	3,990	4,148	(158)	-3.8%
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	1,758,715	1,832,742	(74,027)	-4.0%
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	1,600	1,674	(74)	-4.4%
8b	Oil Spill Cleanup/Response Equipment-Capital	73,475	71,718	1,757	2.4%
10	Relocate Storm Water Runoff-Capital	9,743	10,229	(486)	-4.8%
NA	SO2 Allowances-Negative Return on Investment	(186,275)	(254,313)	68,038	-26.8%
12	Scherer Discharge Pipeline-Capital	64,314	67,361	(3,047)	-4.5%
17b	Disposal of Noncontainerized Liquid Wate-Capital	0	0	0	0.0%
20	Wastewater Discharge Elimination & Reuse	245,826	257,983	(12,157)	-4.7%
21	St. Lucie Turtle Net	92,461	97,326	(4,865)	-5.0%
22	Pipeline Integrity Management	0	0	0	0.0%
23	SPCC-Spill Prevention, Control & Countermeasures	2,036,766	2,144,544	(107,778)	-5.0%
24	Manatee Reburn	4,886,546	5,019,067	(132,521)	-2.6%
25	Pt. Everglades ESP Technology	11,288,005	11,347,320	(59,315)	-0.5%
26	UST Replacement/Removal	-	67,554	(67,554)	-100.0%
31	CAIR Compliance	1,551,150	4,293,310	(2,742,160)	-63.9%
33	CAMR Compliance	340,077	1,594,640	(1,254,563)	-78.7%
35	Martin Plant Drinking Water System Compliance	0	0	0	100.0%
2	Total Investment Projects-Recoverable Costs	$ 24,100,190	$ 28,572,837	$ (4,472,647)	-15.7%
3	Recoverable Costs Allocated to Energy	$ 18,397,312	$ 18,932,935	$ (535,623)	-2.8%
4	Recoverable Costs Allocated to Demand	$ 5,702,878	$ 9,639,902	$ (3,937,024)	-40.8%

Notes:
Column(1) is the 12-Month Totals on Form 42-7E
Column(2) is the approved projected amount in accordance with
FPSC Order No. PSC-06-0972-FOF-EI
Column(3) = Column(1) - Column(2)
Column(4) = Column(3) / Column(2)

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/actual True-up Amount for the Period
January 2007 - December 2007

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line # Project #	Actual JAN	Actual FEB	Actual MAR	Actual APR	Actual MAY	Actual JUN	6-Month Sub-Total
1 Description of Investment Projects (A)							
2 Low NOx Burner Technology-Capital	78,002	77,587	77,172	76,730	76,289	75,874	461,654
3b Continuous Emission Monitoring Systems-Capital	86,718	86,399	86,110	85,787	85,483	85,248	515,745
4b Clean Closure Equivalency-Capital	338	337	336	335	334	333	2,013
5b Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	148,800	148,393	147,985	147,578	147,171	146,763	886,690
7 Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	135	135	134	134	134	133	805
8b Oil Spill Cleanup/Response Equipment-Capital	6,035	5,997	5,961	5,926	5,940	5,947	35,806
10 Relocate Storm Water Runoff-Capital	819	818	816	815	814	813	4,895
NA SO2 Allowances-Negative Return on Investment	-19,422	-19,315	-19,208	-19,101	-17,527	-15,592	-110,165
12 Scherer Discharge Pipeline-Capital	5,417	5,407	5,396	5,386	5,375	5,365	32,346
17b Disposal of Noncontainerized Liquid Waste-Capital	0	0	0	0	0	0	0
20 Wastewater Discharge Elimination &Reuse	20,671	20,637	20,604	20,570	20,536	20,502	123,520
21 St. Lucie Turtle Net	7,754	7,745	7,736	7,727	7,718	7,710	46,390
22 Pipeline Integrity Management	0	0	0	0	0	0	0
23 SPCC - Spill Prevention, Control & Countermeasures	163,718	166,878	168,591	168,533	170,666	172,206	1,010,592
24 Manatee Reburn	382,830	381,974	381,117	380,166	379,142	405,708	2,310,937
25 Pt. Everglades ESP Technology	732,367	848,999	868,422	887,706	913,016	962,744	5,213,254
26 UST Removal / Replacement	0	0	0	0	0	0	0
31 CAIR Compliance	33,991	46,084	55,584	64,479	83,186	103,675	386,999
33 CAMR Compliance	4,539	6,005	6,353	7,537	8,988	15,031	48,453
35 Martin Plant Drinking Water System Compliance	0	0	0	0	0	0	0
2 Total Investment Projects - Recoverable Costs	$ 1,652,712	$ 1,784,080	$ 1,813,109	$ 1,840,308	$ 1,887,265	$ 1,992,460	$ 10,969,934
3 Recoverable Costs Allocated to Energy	$ 1,290,666	$ 1,407,062	$ 1,425,882	$ 1,444,290	$ 1,471,085	$ 1,550,788	$ 8,589,772
4 Recoverable Costs Allocated to Demand	$ 362,046	$ 377,018	$ 387,227	$ 396,018	$ 416,180	$ 441,672	$ 2,380,162
5 Retail Energy Jurisdictional Factor	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%	
6 Retail Demand Jurisdictional Factor	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%	
7 Jurisdictional Energy Recoverable Costs (B)	$ 1,272,471	$ 1,387,227	$ 1,405,781	$ 1,423,929	$ 1,450,347	$ 1,528,927	$ 8,468,682
8 Jurisdictional Demand Recoverable Costs (C)	$ 357,287	$ 372,061	$ 382,136	$ 390,812	$ 410,709	$ 435,866	$ 2,348,871
9 Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 1,629,758	$ 1,759,288	$ 1,787,917	$ 1,814,741	$ 1,861,056	$ 1,964,793	$ 10,817,553

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

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Estimated/actual True-up Amount for the Period
January 2007 - December 2007

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line # Project #	Estimated JUL	Estimated AUG	Estimated SEP	Estimated OCT	Estimated NOV	Estimated DEC	6-Month Sub-Total	12-Month Total	Method of Classification Demand	Method of Classification Energy
1 Description of Investment Projects (A)										
2 Low NOx Burner Technology-Capital	75,460	75,045	74,631	74,217	73,802	73,388	446,543	908,197		908,197
3b Continuous Emission Monitoring Systems-Capital	85,204	85,118	84,841	84,717	84,963	85,012	509,855	1,025,600		1,025,600
4b Clean Closure Equivalency-Capital	332	331	330	329	328	327	1,977	3,990	3,683	307
5b Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	146,356	145,949	145,541	145,134	144,726	144,319	872,025	1,758,715	1,623,429	135,286
7 Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	133	133	133	132	132	132	795	1,600	1,477	123
8b Oil Spill Cleanup/Response Equipment-Capital	6,168	6,307	6,270	6,233	6,195	6,496	37,669	73,475	67,823	5,652
10 Relocate Storm Water Runoff-Capital	811	810	809	807	806	805	4,848	9,743	8,994	749
NA SO2 Allowances-Negative Return on Investment	-14,761	-13,931	-13,100	-12,270	-11,439	-10,609	-76,110	-186,275		-186,275
12 Scherer Discharge Pipeline-Capital	5,354	5,344	5,333	5,323	5,312	5,302	31,968	64,314	59,367	4,947
17b Disposal of Noncontainerized Liquid Waste-Capital	0	0	0	0	0	0	0	0	0	0
20 Wastewater Discharge Elimination &Reuse	20,469	20,435	20,401	20,367	20,334	20,300	122,306	245,826	226,916	18,910
21 St. Lucie Turtle Net	7,701	7,692	7,683	7,674	7,665	7,656	46,071	92,461	85,349	7,112
22 Pipeline Integrity Management	0	0	0	0	0	0	0	0	0	0
23 SPCC - Spill Prevention, Control & Countermeasures	171,987	171,604	171,221	170,837	170,454	170,071	1,026,174	2,036,766	1,880,092	156,674
24 Manatee Reburn	432,203	431,029	429,855	428,681	427,507	426,334	2,575,609	4,886,546		4,886,546
25 Pt. Everglades ESP Technology	1,004,688	1,014,292	1,016,555	1,015,791	1,013,125	1,010,300	6,074,751	11,288,005		11,288,005
26 UST Removal / Replacement	0	0	0	0	0	0	0	0	0	0
31 CAIR Compliance	125,719	154,151	185,167	211,672	231,400	256,042	1,164,151	1,551,150	1,431,831	119,319
33 CAMR Compliance	21,719	27,243	40,287	55,526	68,180	78,669	291,624	340,077	313,917	26,160
35 Martin Plant Drinking Water System Compliance	0	0	0	0	0	0	0	0	0	0
2 Total Investment Projects - Recoverable Costs	$ 2,089,543	$ 2,131,552	$ 2,175,957	$ 2,215,170	$ 2,243,490	$ 2,274,544	$ 13,130,256	$ 24,100,190	$ 5,702,878	$ 18,397,312
3 Recoverable Costs Allocated to Energy	$ 1,621,775	$ 1,633,091	$ 1,637,642	$ 1,639,139	$ 1,638,384	$ 1,637,511	$ 9,807,541	$ 18,397,312		
4 Recoverable Costs Allocated to Demand	$ 467,768	$ 498,461	$ 538,315	$ 576,031	$ 605,106	$ 637,033	$ 3,322,715	$ 5,702,878		
5 Retail Energy Jurisdictional Factor	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%	98.59030%				
6 Retail Demand Jurisdictional Factor	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%	98.68536%				
7 Jurisdictional Energy Recoverable Costs (B)	$ 1,598,913	$ 1,610,070	$ 1,614,556	$ 1,616,032	$ 1,615,287	$ 1,614,427	$ 9,669,285	$ 18,137,967		
8 Jurisdictional Demand Recoverable Costs (C)	$ 461,619	$ 491,908	$ 531,238	$ 568,459	$ 597,151	$ 628,658	$ 3,279,033	$ 5,627,904		
9 Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 2,060,532	$ 2,101,978	$ 2,145,794	$ 2,184,491	$ 2,212,438	$ 2,243,085	$ 12,948,318	$ 23,765,871		

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

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements					$35,815			$35,815
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$17,509,209	17,509,209	17,509,209	17,509,209	17,473,393	17,473,393	17,473,393	n/a
3.	Less: Accumulated Depreciation (C)	13,903,927	13,948,794	13,993,662	14,038,529	14,047,554	14,092,367	14,137,181	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$3,605,282	$3,560,414	$3,515,547	$3,470,680	$3,425,840	$3,381,026	$3,336,213	n/a
6.	Average Net Investment		3,582,848	3,537,981	3,493,114	3,448,260	3,403,433	3,358,619	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		27,531	27,186	26,842	26,497	26,153	25,808	160,017
	b. Debt Component (Line 6 x 1.8767% x 1/12)		5,603	5,533	5,463	5,393	5,323	5,253	32,567
8.	Investment Expenses								
	a. Depreciation (E)		44,867	44,867	44,867	44,840	44,813	44,813	269,069
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$78,002	$77,587	$77,172	$76,730	$76,289	$75,874	$461,654

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								$35,815
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$17,473,393	17,473,393	17,473,393	17,473,393	17,473,393	17,473,393	17,473,393	n/a
3.	Less: Accumulated Depreciation (C)	14,137,181	14,181,994	14,226,808	14,271,621	14,316,435	14,361,248	14,406,061	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$3,336,213	$3,291,399	$3,246,586	$3,201,772	$3,156,959	$3,112,145	$3,067,332	n/a
6.	Average Net Investment		3,313,806	3,268,993	3,224,179	3,179,366	3,134,552	3,089,739	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		25,464	25,119	24,775	24,431	24,086	23,742	307,635
	b. Debt Component (Line 6 x 1.8767% x 1/12)		5,183	5,112	5,042	4,972	4,902	4,832	62,611
8.	Investment Expenses								
	a. Depreciation (E)		44,813	44,813	44,813	44,813	44,813	44,813	537,950
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$75,460	$75,045	$74,631	$74,217	$73,802	$73,388	$908,197

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant				($2,635)	$3,268		$18,307	$18,939
	c. Retirements					$3,478		$32,522	$36,000
	d. Other (A)								$0
2.	Plant-In-Service/Depreciation Base (B)	$12,613,846	12,613,846	12,613,846	12,611,211	12,611,001	12,611,001	12,596,785	0
3.	Less: Accumulated Depreciation (C)	6,949,745	6,984,241	7,018,736	7,053,274	7,084,327	7,118,859	7,120,868	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$5,664,101	$5,629,605	$5,595,110	$5,557,937	$5,526,674	$5,492,142	$5,475,917	n/a
6.	Average Net Investment		5,646,853	5,612,358	5,576,523	5,542,305	5,509,408	5,484,030	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		43,391	43,126	42,851	42,588	42,335	42,140	256,432
	b. Debt Component (Line 6 x 1.8767% x 1/12)		8,831	8,777	8,721	8,668	8,616	8,577	52,190
8.	Investment Expenses								
	a. Depreciation (E)		34,496	34,496	34,537	34,531	34,531	34,532	207,123
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$86,718	$86,399	$86,110	$85,787	$85,483	$85,248	$515,745

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$34,000	$7,000		$28,000	$56,000		$143,939
	c. Retirements								$36,000
	d. Other (A)								$0
2.	Plant-In-Service/Depreciation Base (B)	$12,596,785	12,630,785	12,637,785	12,637,785	12,665,785	12,721,785	12,721,785	n/a
3.	Less: Accumulated Depreciation (C)	7,120,868	7,155,433	7,190,042	7,224,662	7,259,349	7,294,215	7,329,194	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$5,475,917	$5,475,352	$5,447,743	$5,413,123	$5,406,436	$5,427,570	$5,392,591	n/a
6.	Average Net Investment		5,475,635	5,461,548	5,430,433	5,409,780	5,417,003	5,410,080	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		42,076	41,967	41,728	41,570	41,625	41,572	506,970
	b. Debt Component (Line 6 x 1.8767% x 1/12)		8,563	8,541	8,493	8,460	8,472	8,461	103,181
8.	Investment Expenses								
	a. Depreciation (E)		34,565	34,609	34,620	34,687	34,867	34,979	415,450
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$85,204	$85,118	$84,841	$84,717	$84,963	$85,012	$1,025,600

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$58,866	58,866	58,866	58,866	58,866	58,866	58,866	n/a
3.	Less: Accumulated Depreciation (C)	34,252	34,362	34,473	34,584	34,695	34,806	34,916	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$24,614	$24,504	$24,393	$24,282	$24,171	$24,060	$23,950	n/a
6.	Average Net Investment		24,559	24,448	24,337	24,227	24,116	24,005	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		189	188	187	186	185	184	1,120
	b. Debt Component (Line 6 x 1.8767% x 1/12)		38	38	38	38	38	38	228
8.	Investment Expenses								
	a. Depreciation (E)		111	111	111	111	111	111	665
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$338	$337	$336	$335	$334	$333	$2,013

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$58,866	58,866	58,866	58,866	58,866	58,866	58,866	n/a
3.	Less: Accumulated Depreciation (C)	34,916	35,027	35,138	35,249	35,360	35,470	35,581	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$23,950	$23,839	$23,728	$23,617	$23,506	$23,396	$23,285	n/a
6.	Average Net Investment		23,894	23,783	23,673	23,562	23,451	23,340	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		184	183	182	181	180	179	2,208
	b. Debt Component (Line 6 x 1.8767% x 1/12)		37	37	37	37	37	37	449
8.	Investment Expenses								
	a. Depreciation (E)		111	111	111	111	111	111	1,330
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$332	$331	$330	$329	$328	$327	$3,990

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant								$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	n/a
3.	Less: Accumulated Depreciation (C)	2,201,151	2,245,197	2,289,244	2,333,290	2,377,337	2,421,383	2,465,430	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$11,349,067	$11,305,020	$11,260,974	$11,216,927	$11,172,881	$11,128,834	$11,084,788	n/a
6.	Average Net Investment		11,327,044	11,282,997	11,238,951	11,194,904	11,150,858	11,106,811	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		87,039	86,700	86,362	86,024	85,685	85,347	517,157
	b. Debt Component (Line 6 x 1.8767% x 1/12)		17,715	17,646	17,577	17,508	17,439	17,370	105,254
8.	Investment Expenses								
	a. Depreciation (E)		44,046	44,046	44,046	44,046	44,046	44,046	264,279
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$148,800	$148,393	$147,985	$147,578	$147,171	$146,763	$886,690

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant								$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	13,550,218	n/a
3.	Less: Accumulated Depreciation (C)	2,465,430	2,509,476	2,553,523	2,597,569	2,641,616	2,685,662	2,729,709	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$11,084,788	$11,040,742	$10,996,695	$10,952,649	$10,908,602	$10,864,556	$10,820,509	n/a
6.	Average Net Investment		11,062,765	11,018,718	10,974,672	10,930,625	10,886,579	10,842,532	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		85,008	84,670	84,331	83,993	83,654	83,316	1,022,128
	b. Debt Component (Line 6 x 1.8767% x 1/12)		17,301	17,232	17,163	17,095	17,026	16,957	208,028
8.	Investment Expenses								
	a. Depreciation (E)		44,046	44,046	44,046	44,046	44,046	44,046	528,558
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$146,356	$145,949	$145,541	$145,134	$144,726	$144,319	$1,758,715

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$31,030	31,030	31,030	31,030	31,030	31,030	31,030	n/a
3.	Less: Accumulated Depreciation (C)	19,782	19,813	19,844	19,875	19,906	19,937	19,968	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$11,248	$11,217	$11,186	$11,155	$11,124	$11,093	$11,062	n/a
6.	Average Net Investment		11,232	11,201	11,170	11,139	11,108	11,077	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		86	86	86	86	85	85	514
	b. Debt Component (Line 6 x 1.8767% x 1/12)		18	18	17	17	17	17	105
8.	Investment Expenses								
	a. Depreciation (E)		31	31	31	31	31	31	186
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$135	$135	$134	$134	$134	$133	$805

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$31,030	31,030	31,030	31,030	31,030	31,030	31,030	n/a
3.	Less: Accumulated Depreciation (C)	19,968	19,999	20,030	20,061	20,092	20,123	20,154	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$11,062	$11,031	$11,000	$10,969	$10,938	$10,907	$10,876	n/a
6.	Average Net Investment		11,046	11,015	10,984	10,953	10,922	10,891	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		85	85	84	84	84	84	1,020
	b. Debt Component (Line 6 x 1.8767% x 1/12)		17	17	17	17	17	17	208
8.	Investment Expenses								
	a. Depreciation (E)		31	31	31	31	31	31	372
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$133	$133	$133	$132	$132	$132	$1,600

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Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
a.	Expenditures/Additions								
b.	Clearings to Plant		$1,997	$0	$0	$0	$531	$7,691	$10,219
c.	Retirements								
d.	Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$342,502	344,499	344,499	344,499	344,499	345,030	352,721	n/a
3.	Less: Accumulated Depreciation (C)	106,058	109,915	113,760	117,605	121,451	125,343	129,241	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$236,445	$234,585	$230,739	$226,894	$223,049	$219,687	$223,480	n/a
6.	Average Net Investment		235,515	232,662	228,817	224,971	221,368	221,584	
7.	Return on Average Net Investment								
a.	Equity Component grossed up for taxes (D)		1,810	1,788	1,758	1,729	1,701	1,703	10,488
b.	Debt Component (Line 6 x 1.8767% x 1/12)		368	364	358	352	346	347	2,135
8.	Investment Expenses								
a.	Depreciation (E)		3,857	3,845	3,845	3,845	3,893	3,897	23,183
b.	Amortization (F)								
c.	Dismantlement								
d.	Property Expenses								
e.	Other (G)								
9.	*Total System Recoverable Expenses* (Lines 7 & 8)		$6,035	$5,997	$5,961	$5,926	$5,940	$5,947	$35,806

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$28,000					$32,000	$70,219
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$352,721	380,721	380,721	380,721	380,721	380,721	412,721	n/a
3.	Less: Accumulated Depreciation (C)	129,241	133,231	137,268	141,306	145,343	149,380	153,608	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$223,480	$247,490	$243,453	$239,415	$235,378	$231,341	$259,113	n/a
6.	Average Net Investment		235,485	245,471	241,434	237,397	233,360	245,227	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		1,810	1,886	1,855	1,824	1,793	1,884	21,541
	b. Debt Component (Line 6 x 1.8767% x 1/12)		368	384	378	371	365	384	4,384
8.	Investment Expenses								
	a. Depreciation (E)		3,990	4,037	4,037	4,037	4,037	4,228	47,550
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$6,168	$6,307	$6,270	$6,233	$6,195	$6,496	$73,475

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$117,794	117,794	117,794	117,794	117,794	117,794	117,794	n/a
3.	Less: Accumulated Depreciation (C)	44,037	44,174	44,311	44,449	44,586	44,724	44,861	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$73,757	$73,620	$73,483	$73,345	$73,208	$73,070	$72,933	n/a
6.	Average Net Investment		73,689	73,551	73,414	73,277	73,139	73,002	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		566	565	564	563	562	561	3,382
	b. Debt Component (Line 6 x 1.8767% x 1/12)		115	115	115	115	114	114	688
8.	Investment Expenses								
	a. Depreciation (E)		137	137	137	137	137	137	825
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$819	$818	$816	$815	$814	$813	$4,895

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
a.	Expenditures/Additions								
b.	Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
c.	Retirements								
d.	Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$117,794	117,794	117,794	117,794	117,794	117,794	117,794	n/a
3.	Less: Accumulated Depreciation (C)	44,861	44,998	45,136	45,273	45,411	45,548	45,686	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$72,933	$72,796	$72,658	$72,521	$72,383	$72,246	$72,108	n/a
6.	Average Net Investment		72,864	72,727	72,589	72,452	72,315	72,177	
7.	Return on Average Net Investment								
a.	Equity Component grossed up for taxes (D)		560	559	558	557	556	555	6,725
b.	Debt Component (Line 6 x 1.8767% x 1/12)		114	114	114	113	113	113	1,369
8.	Investment Expenses								
a.	Depreciation (E)		137	137	137	137	137	137	1,649
b.	Amortization (F)								
c.	Dismantlement								
d.	Property Expenses								
e.	Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$811	$810	$809	$807	$806	$805	$9,743

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$864,260	864,260	864,260	864,260	864,260	864,260	864,260	n/a
3.	Less: Accumulated Depreciation (C)	401,043	402,181	403,320	404,459	405,598	406,736	407,875	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$463,217	$462,079	$460,940	$459,801	$458,662	$457,524	$456,385	n/a
6.	Average Net Investment		462,648	461,509	460,370	459,232	458,093	456,954	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,555	3,546	3,538	3,529	3,520	3,511	21,199
	b. Debt Component (Line 6 x 1.8767% x 1/12)		724	722	720	718	716	715	4,315
8.	Investment Expenses								
	a. Depreciation (E)		1,139	1,139	1,139	1,139	1,139	1,139	6,833
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$5,417	$5,407	$5,396	$5,386	$5,375	$5,365	$32,346

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$864,260	864,260	864,260	864,260	864,260	864,260	864,260	n/a
3.	Less: Accumulated Depreciation (C)	407,875	409,014	410,153	411,291	412,430	413,569	414,708	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$456,385	$455,246	$454,107	$452,969	$451,830	$450,691	$449,552	n/a
6.	Average Net Investment		455,815	454,677	453,538	452,399	451,260	450,122	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		3,503	3,494	3,485	3,476	3,468	3,459	42,083
	b. Debt Component (Line 6 x 1.8767% x 1/12)		713	711	709	708	706	704	8,565
8.	Investment Expenses								
	a. Depreciation (E)		1,139	1,139	1,139	1,139	1,139	1,139	13,665
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$5,354	$5,344	$5,333	$5,323	$5,312	$5,302	$64,314

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	0
8.	Investment Expenses								
	a. Depreciation (E)								0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
a.	Expenditures/Additions								
b.	Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
c.	Retirements								
d.	Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	n/a
3.	Less: Accumulated Depreciation (C)	519,211	522,860	526,508	530,157	533,806	537,454	541,103	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$1,842,451	$1,838,802	$1,835,153	$1,831,505	$1,827,856	$1,824,207	$1,820,559	n/a
6.	Average Net Investment		1,840,627	1,836,978	1,833,329	1,829,680	1,826,032	1,822,383	
7.	Return on Average Net Investment								
a.	Equity Component grossed up for taxes (D)		14,144	14,116	14,088	14,060	14,032	14,003	84,442
b.	Debt Component (Line 6 x 1.8767% x 1/12)		2,879	2,873	2,867	2,861	2,856	2,850	17,186
8.	Investment Expenses								
a.	Depreciation (E)		3,649	3,649	3,649	3,649	3,649	3,649	21,892
b.	Amortization (F)								
c.	Dismantlement								
d.	Property Expenses								
e.	Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$20,671	$20,637	$20,604	$20,570	$20,536	$20,502	$123,520

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

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

Line	Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1. Investments								
a. Expenditures/Additions								
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
c. Retirements								
d. Other (A)								
2. Plant-In-Service/Depreciation Base (B)	$2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	2,361,662	n/a
3. Less: Accumulated Depreciation (C)	$541,103	544,752	548,401	552,049	555,698	559,347	562,995	n/a
4. CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5. Net Investment (Lines 2 - 3 + 4)	$1,820,559	$1,816,910	$1,813,261	$1,809,612	$1,805,964	$1,802,315	$1,798,666	n/a
6. Average Net Investment		1,818,734	1,815,086	1,811,437	1,807,788	1,804,139	1,800,491	
7. Return on Average Net Investment								
Equity Component grossed up for taxes (D)		13,975	13,947	13,919	13,891	13,863	13,835	167,874
Debt Component (Line 6 x 1.8767% x 1/12)		2,844	2,839	2,833	2,827	2,822	2,816	34,166
8. Investment Expenses								
a. Depreciation (E)		3,649	3,649	3,649	3,649	3,649	3,649	43,785
b. Amortization (F)								
c. Dismantlement								
d. Property Expenses								
e. Other (G)								
9. Total System Recoverable Expenses (Lines 7 & 8)		$20,469	$20,435	$20,401	$20,367	$20,334	$20,300	$245,826

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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

Line	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1. Investments								
a. Expenditures/Additions								
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
c. Retirements								
d. Other (A)								
2. Plant-In-Service/Depreciation Base (B)	$828,789	828,789	828,789	828,789	828,789	828,789	828,789	n/a
3. Less: Accumulated Depreciation (C)	94,388	95,355	96,322	97,289	98,256	99,223	100,190	n/a
4. CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5. Net Investment (Lines 2 - 3 + 4)	$734,401	$733,434	$732,467	$731,500	$730,533	$729,566	$728,599	n/a
6. Average Net Investment		733,917	732,950	731,983	731,017	730,050	729,083	
7. Return on Average Net Investment								
a. Equity Component grossed up for taxes (D)		5,640	5,632	5,625	5,617	5,610	5,602	33,726
b. Debt Component (Line 6 x 1.8767% x 1/12)		1,148	1,146	1,145	1,143	1,142	1,140	6,864
8. Investment Expenses								
a. Depreciation (E)		967	967	967	967	967	967	5,802
b. Amortization (F)								
c. Dismantlement								
d. Property Expenses								
e. Other (G)								
9. Total System Recoverable Expenses (Lines 7 & 8)		$7,754	$7,745	$7,736	$7,727	$7,718	$7,710	$46,390

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$828,789	828,789	828,789	828,789	828,789	828,789	828,789	n/a
3.	Less: Accumulated Depreciation (C)	$100,190	101,157	102,124	103,091	104,057	105,024	105,991	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$728,599	$727,632	$726,665	$725,698	$724,732	$723,765	$722,798	n/a
6.	Average Net Investment		728,116	727,149	726,182	725,215	724,248	723,281	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		5,595	5,588	5,580	5,573	5,565	5,558	67,184
	b. Debt Component (Line 6 x 1.8767% x 1/12)		1,139	1,137	1,136	1,134	1,133	1,131	13,674
8.	Investment Expenses								
	a. Depreciation (E)		967	967	967	967	967	967	11,603
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$7,701	$7,692	$7,683	$7,674	$7,665	$7,656	$92,461

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Pipeline Integrity Management (Project No. 22)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	0
8.	Investment Expenses								
	a. Depreciation (E)								0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Pipeline Integrity Management (Project No. 22)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	0
8.	Investment Expenses								
	a. Depreciation (E)								0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

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Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$241,305	$360,467	$31,078	$28,672	$382,656	$30,426	$1,074,604
	c. Retirements								
	d. Other (A)						$2,738		
2.	Plant-In-Service/Depreciation Base (B)	$14,364,448	14,605,753	14,966,220	14,997,298	15,025,970	15,408,626	15,439,052	n/a
3.	Less: Accumulated Depreciation (C)	1,053,048	1,092,729	1,133,158	1,173,864	1,214,612	1,258,722	1,300,119	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$13,311,400	$13,513,024	$13,833,062	$13,823,434	$13,811,358	$14,149,904	$14,138,932	n/a
6.	Average Net Investment		13,412,212	13,673,043	13,828,248	13,817,396	13,980,631	14,144,418	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		103,062	105,066	106,259	106,175	107,430	108,688	636,679
	b. Debt Component (Line 6 x 1.8767% x 1/12)		20,976	21,384	21,626	21,609	21,865	22,121	129,580
8.	Investment Expenses								
	a. Depreciation (E)		39,681	40,429	40,706	40,749	41,372	41,397	244,334
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$163,718	$166,878	$168,591	$168,533	$170,666	$172,206	$1,010,592

Notes:

(A) Reserve Transfer/Adj.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant								$1,074,604
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$15,439,052	15,439,052	15,439,052	15,439,052	15,439,052	15,439,052	15,439,052	n/a
3.	Less: Accumulated Depreciation (C)	$1,300,119	1,341,540	1,382,960	1,424,380	1,465,800	1,507,220	1,548,640	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$14,138,932	$14,097,512	$14,056,092	$14,014,672	$13,973,252	$13,931,832	$13,890,412	n/a
6.	Average Net Investment		14,118,222	14,076,802	14,035,382	13,993,962	13,952,542	13,911,122	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		108,487	108,169	107,850	107,532	107,214	106,895	1,282,826
	b. Debt Component (Line 6 x 1.8767% x 1/12)		22,080	22,015	21,950	21,885	21,821	21,756	261,086
8.	Investment Expenses								
	a. Depreciation (E)		41,420	41,420	41,420	41,420	41,420	41,420	492,854
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$171,987	$171,604	$171,221	$170,837	$170,454	$170,071	$2,036,766

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Reburn (Project No. 24)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$11,713	$15,650	$11,534	$654	$0	$4,275,321	$4,314,872
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$30,223,167	30,234,879	30,250,530	30,262,064	30,262,718	30,262,718	34,538,039	n/a
3.	Less: Accumulated Depreciation (C)	789,407	900,491	1,011,620	1,122,794	1,233,989	1,345,184	1,464,242	n/a
4.	CWIP - *Non Interest Bearing*		0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$29,433,759	$29,334,388	$29,238,910	$29,139,270	$29,028,729	$28,917,533	$33,073,796	n/a
6.	Average Net Investment		29,384,074	29,286,649	29,189,090	29,083,999	28,973,131	30,995,665	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		225,792	225,044	224,294	223,486	222,634	238,176	1,359,426
	b. Debt Component (Line 6 x 1.8767% x 1/12)		45,954	45,802	45,649	45,485	45,312	48,475	276,677
8.	Investment Expenses								
	a. Depreciation (E)		111,083	111,129	111,174	111,195	111,196	119,058	674,835
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$382,830	$381,974	$381,117	$380,166	$379,142	$405,708	$2,310,937

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Reburn (Project No. 24)
(In Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$4,314,872
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$34,538,039	34,538,039	34,538,039	34,538,039	34,538,039	34,538,039	34,538,039	n/a
3.	Less: Accumulated Depreciation (C)	$1,464,242	1,591,163	1,718,083	1,845,003	1,971,923	2,098,843	2,225,764	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$33,073,796	$32,946,876	$32,819,956	$32,693,036	$32,566,116	$32,439,195	$32,312,275	n/a
6.	Average Net Investment		33,010,336	32,883,416	32,756,496	32,629,576	32,502,655	32,375,735	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		253,657	252,682	251,706	250,731	249,756	248,781	$2,866,739
	b. Debt Component (Line 6 x 1.8767% x 1/12)		51,625	51,427	51,228	51,030	50,831	50,633	$583,452
8.	Investment Expenses								
	a. Depreciation (E)		126,920	126,920	126,920	126,920	126,920	126,920	$1,436,356
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$432,203	$431,029	$429,855	$428,681	$427,507	$426,334	$4,886,546

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Port Everglades ESP (Project No. 25)
(In Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$4,952,476	$1,595,352	$2,248,017	$2,100,583	$1,249,385	$0	$12,145,814
	b. Clearings to Plant		24,971,594	572,501	42,942	170,427	1,781,492	$22,004,185	$49,543,141
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$29,934,156	54,905,750	55,478,251	55,521,194	55,691,620	57,473,112	79,477,297	n/a
3.	Less: Accumulated Depreciation (C)	2,579,857	2,770,709	2,998,123	3,226,451	3,455,081	3,686,633	3,952,945	n/a
4.	CWIP - Non Interest Bearing	23,512,393	14,106,905	15,702,257	17,950,275	20,050,858	21,300,243	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$50,866,692	$66,241,946	$68,182,385	$70,245,017	$72,287,397	$75,086,722	$75,524,351	n/a
6.	Average Net Investment		58,554,319	67,212,166	69,213,701	71,266,207	73,687,059	75,305,537	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		449,941	516,470	531,850	547,621	566,224	578,660	3,190,766
	b. Debt Component (Line 6 x 1.8767% x 1/12)		91,574	105,114	108,244	111,454	115,240	117,772	649,399
8.	Investment Expenses								
	a. Depreciation (E)		190,851	227,415	228,328	228,630	231,552	266,312	1,373,088
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$732,367	$848,999	$868,422	$887,706	$913,016	$962,744	$5,213,254

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Port Everglades ESP (Project No. 25)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$12,145,814
	b. Clearings to Plant		$1,506,362	$511,848	$319,212	$26,000	$0	$0	$51,906,563
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$79,477,297	80,983,659	81,495,507	81,814,719	81,840,719	81,840,719	81,840,719	n/a
3.	Less: Accumulated Depreciation (C)	$3,952,945	4,253,603	4,557,326	4,862,285	5,167,705	5,473,164	5,778,624	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$75,524,351	$76,730,056	$76,938,180	$76,952,434	$76,673,014	$76,367,554	$76,062,095	n/a
6.	Average Net Investment		76,127,204	76,834,118	76,945,307	76,812,724	76,520,284	76,214,825	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		584,974	590,406	591,261	590,242	587,995	585,647	$6,721,291
	b. Debt Component (Line 6 x 1.8767% x 1/12)		119,057	120,162	120,336	120,129	119,671	119,194	$1,367,948
8.	Investment Expenses								
	a. Depreciation (E)		300,657	303,724	304,958	305,420	305,459	305,459	$3,198,766
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,004,688	$1,014,292	$1,016,555	$1,015,791	$1,013,125	$1,010,300	$11,288,005

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Return on Capital Investments, Depreciation and Taxes
For Project: UST Removal / Replacement (Project No. 26)
(In Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: UST Removal / Replacement (Project No. 26)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	$0
8.	Investment Expenses								
	a. Depreciation (E)		0						$0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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Return on Capital Investments, Depreciation and Taxes
For Project: CAIR Compliance (Project No. 31)
(in Dollars)

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Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$1,140,561	$1,474,564	$579,965	$1,343,744	$2,701,874	$1,729,136	$8,969,845
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	3,105,197	4,245,758	5,720,322	6,300,288	7,644,032	10,345,905	12,075,042	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$3,105,197	$4,245,758	$5,720,322	$6,300,288	$7,644,032	$10,345,905	$12,075,042	n/a
6.	Average Net Investment		3,675,477	4,983,040	6,010,305	6,972,160	8,994,968	11,210,473	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		28,243	38,291	46,184	53,575	69,119	86,143	321,555
	b. Debt Component (Line 6 x 1.8767% x 1/12)		5,748	7,793	9,400	10,904	14,067	17,532	65,444
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$33,991	$46,084	$55,584	$64,479	$83,186	$103,675	$386,999

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR Compliance (Project No. 31)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$3,037,978	$3,110,808	$3,596,768	$2,135,158	$2,131,205	$3,104,216	$26,085,978
	b. Clearings to Plant		$0	$0	$0	$0	$0	$396,999	$396,999
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	396,999	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	436	n/a
4.	CWIP - Non Interest Bearing	$12,075,042	15,113,020	18,223,828	21,820,596	23,955,754	26,086,959	28,794,176	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$12,075,042	$15,113,020	$18,223,828	$21,820,596	$23,955,754	$26,086,959	$29,190,739	n/a
6.	Average Net Investment		13,594,031	16,668,424	20,022,212	22,888,175	25,021,356	27,638,849	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		104,459	128,083	153,854	175,877	192,268	212,382	$1,288,477
	b. Debt Component (Line 6 x 1.8767% x 1/12)		21,260	26,068	31,313	35,795	39,131	43,225	$262,237
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	436	$436
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$125,719	$154,151	$185,167	$211,672	$231,400	$256,042	$1,551,150

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Return on Capital Investments, Depreciation and Taxes
For Project: CAMR Compliance (Project No. 33)
(in Dollars)

Line	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1. Investments								
a. Expenditures/Additions		$258,550	$58,605	$16,677	$239,395	$74,270	$1,232,705	$1,880,201
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0
d. Other (A)								
2. Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3. Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4. CWIP - Non Interest Bearing	361,479	620,029	678,634	695,311	934,706	1,008,976	2,241,681	n/a
5. Net Investment (Lines 2 - 3 + 4)	$361,479	$620,029	$678,634	$695,311	$934,706	$1,008,976	$2,241,681	n/a
6. Average Net Investment		490,754	649,331	686,972	815,008	971,841	1,625,328	n/a
7. Return on Average Net Investment								
a. Equity Component grossed up for taxes (D)		3,771	4,990	5,279	6,263	7,468	12,489	40,259
b. Debt Component (Line 6 x 1.8767% x 1/12)		767	1,016	1,074	1,275	1,520	2,542	8,194
8. Investment Expenses								
a. Depreciation (E)		0	0	0	0	0	0	0
b. Amortization (F)								
c. Dismantlement								
d. Property Expenses								
e. Other (G)								
9. Total System Recoverable Expenses (Lines 7 & 8)		$4,539	$6,005	$6,353	$7,537	$8,988	$15,031	$48,453

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: CAMR Compliance (Project No. 33)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$213,532	$981,085	$1,839,993	$1,455,464	$1,281,128	$987,378	$8,638,781
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$2,241,681	2,455,213	3,436,298	5,276,291	6,731,755	8,012,883	9,000,261	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$2,241,681	$2,455,213	$3,436,298	$5,276,291	$6,731,755	$8,012,883	$9,000,261	n/a
6.	Average Net Investment		2,348,447	2,945,755	4,356,294	6,004,023	7,372,319	8,506,572	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		18,046	22,636	33,474	46,136	56,650	65,366	$282,567
	b. Debt Component (Line 6 x 1.8767% x 1/12)		3,673	4,607	6,813	9,390	11,530	13,304	$57,509
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$21,719	$27,243	$40,287	$55,526	$68,180	$78,669	$340,077

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Martin Drinking Water System Complianace (Project No. 35)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

Return on Capital Investments, Depreciation and Taxes
For Project: Martin Drinking Water System Complianace (Project No. 35)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x 1.8767% x 1/12)		0	0	0	0	0	0	$0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-8E, pages 41-43.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 41-43.
(F) Applicable amortization period(s). See Form 42-8E, pages 41-43.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2007

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	End of Period Amount	
1	Working Capital Dr (Cr)									
a	158.100 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0		
b	158.200 Allowances Withheld	0	0	0	0	0	0	0		
c	182.300 Other Regulatory Assets-Losses	0	0	0	0	0	0	0		
d	254.900 Other Regulatory Liabilities-Gains	(2,105,917)	(2,094,333)	(2,082,750)	(2,071,166)	(2,059,583)	(1,730,873)	(1,641,069)		
2	Total Working Capital	($2,105,917)	($2,094,333)	($2,082,750)	($2,071,166)	($2,059,583)	($1,730,873)	($1,641,069)		
3	Average Net Working Capital Balance		(2,100,125)	(2,088,542)	(2,076,958)	(2,065,374)	(1,895,228)	(1,685,971)		
4	Return on Average Net Working Capital Balance									
a	Equity Component grossed up for taxes (A)		(16,138)	(16,049)	(15,960)	(15,871)	(14,563)	(12,955)	(91,535)	
b	Debt Component (Line 6 x 1.87670% x 1/12)		(3,284)	(3,266)	(3,248)	(3,230)	(2,964)	(2,637)	(18,630)	
5	Total Return Component		($19,422)	($19,315)	($19,208)	($19,101)	($17,527)	($15,592)	($110,165)	(D)
6	Expense Dr (Cr)									
a	411.800 Gains from Dispositions of Allowances		(11,584)	(11,584)	(11,584)	(11,584)	(328,710)	(89,804)	(464,848)	
b	411.900 Losses from Dispositions of Allowances		0	0	0	0	0	0	-	
c	509.000 Allowance Expense		0	0	0	0	0	0	-	
7	Net Expense (Lines 6a+6b+6c)		($11,584)	($11,584)	($11,584)	($11,584)	($328,710)	($89,804)	($464,848)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		(7,839)	(7,731)	(7,624)	(7,517)	311,183	74,212		
a	Recoverable Costs Allocated to Energy		(7,839)	(7,731)	(7,624)	(7,517)	311,183	74,212		
b	Recoverable Costs Allocated to Demand		0	0	0	0	0	0		
9	Energy Jurisdictional Factor		98.53348%	98.53348%	98.53348%	98.53348%	98.53348%	98.53348%		
10	Demand Jurisdictional Factor		98.62224%	98.62224%	98.62224%	98.62224%	98.62224%	98.62224%		
11	Retail Energy-Related Recoverable Costs (B)		(7,724)	(7,618)	(7,513)	(7,407)	306,619	73,123	349,482	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($7,724)	($7,618)	($7,513)	($7,407)	$306,619	$73,123	$349,482	

Notes:
(A) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule
(E) Line 7 is reported on O&M Schedule

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

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2007

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	End of Period Amount	
1	Working Capital Dr (Cr)									
a	158.100 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0		
b	158.200 Allowances Withheld	0	0	0	0	0	0	0		
c	182.300 Other Regulatory Assets-Losses	0	0	0	0	0	0	0		
d	254.900 Other Regulatory Liabilities-Gains	(1,641,069)	(1,551,265)	(1,461,461)	(1,371,658)	(1,281,854)	(1,192,050)	(1,102,246)		
2	Total Working Capital	($1,641,069)	($1,551,265)	($1,461,461)	($1,371,658)	($1,281,854)	($1,192,050)	($1,102,246)		
3	Average Net Working Capital Balance		(1,596,167)	(1,506,363)	(1,416,560)	(1,326,756)	(1,236,952)	(1,147,148)		
4	Return on Average Net Working Capital Balance									
a	Equity Component grossed up for taxes (A)		(12,265)	(11,575)	(10,885)	(10,195)	(9,505)	(8,815)	(154,776)	
b	Debt Component (Line 6 x 1.6698% x 1/12)		(2,496)	(2,356)	(2,215)	(2,075)	(1,934)	(1,794)	(31,501)	
5	Total Return Component		($14,761)	($13,931)	($13,100)	($12,270)	($11,439)	($10,609)	($186,276)	(D)
6	Expense Dr (Cr)									
a	411.800 Gains from Dispositions of Allowances		(89,804)	(89,804)	(89,804)	(89,804)	(89,804)	(89,804)	(1,003,670)	
b	411.900 Losses from Dispositions of Allowances		0	0	0	0	0	0	-	
c	509.000 Allowance Expense		0	0	0	0	0	0	-	
7	Net Expense (Lines 6a+6b+6c)		($89,804)	($89,804)	($89,804)	($89,804)	($89,804)	($89,804)	($1,003,670)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		$75,042	$75,873	$76,703	$77,534	$78,364	$79,195		
a	Recoverable Costs Allocated to Energy		75,042	75,873	76,703	77,534	78,364	79,195		
b	Recoverable Costs Allocated to Demand		0	0	0	0	0	0		
9	Energy Jurisdictional Factor		98.53348%	98.53348%	98.53348%	98.53348%	98.53348%	98.53348%		
10	Demand Jurisdictional Factor		98.62224%	98.62224%	98.62224%	98.62224%	98.62224%	98.62224%		
11	Retail Energy-Related Recoverable Costs (B)		73,942	74,760	75,578	76,397	77,215	78,033	805,407	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	
13	Total Jurisdictional Recoverable Costs (Lines11+12)		$73,942	$74,760	$75,578	$76,397	$77,215	$78,033	$805,407	

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Notes:

(A) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule
(E) Line 7 is reported on O&M Schedule

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

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
2007 Annual Capital Depreciation Schedule

Project Number	Function	Plant Name	Plant Account	Depreciation Rate / Amortization Period	Actual 12/31/2006 Plant In Service	Estimated 12/31/2007 Plant In Service
02 - Low NOX Burner Technology						
	02 - Steam Generation Plant	PtEverglades U1	31200	6.7%	2,700,574.97	2,700,574.97
	02 - Steam Generation Plant	PtEverglades U2	31200	6.1%	2,368,972.27	2,368,972.27
	02 - Steam Generation Plant	Riviera U3	31200	1.7%	3,815,802.70	3,815,802.70
	02 - Steam Generation Plant	Riviera U4	31200	1.4%	3,246,925.80	3,246,925.80
	02 - Steam Generation Plant	Turkey Pt U1	31200	2.0%	2,925,027.84	2,925,027.84
	02 - Steam Generation Plant	Turkey Pt U2	31200	1.8%	2,451,904.92	2,416,089.59
		Total For Project 02 - Low NOX Burner Technology			17,509,208.50	17,473,393.17
03 - Continuous Emission Monitoring						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.7%	59,227.10	59,227.10
	02 - Steam Generation Plant	CapeCanaveral Comm	31200	1.3%	30,059.25	30,059.25
	02 - Steam Generation Plant	CapeCanaveral U1	31200	1.4%	494,606.87	494,606.87
	02 - Steam Generation Plant	CapeCanaveral U2	31200	1.1%	511,705.24	511,705.24
	02 - Steam Generation Plant	Cutler Comm	31100	0.0%	64,883.87	64,883.87
	02 - Steam Generation Plant	Cutler Comm	31200	0.5%	27,351.73	27,351.73
	02 - Steam Generation Plant	Cutler U5	31200	0.1%	312,722.43	319,722.43
	02 - Steam Generation Plant	Cutler U6	31200	1.0%	314,129.96	321,129.96
	02 - Steam Generation Plant	Manatee Comm	31200	14.1%	31,859.00	31,859.00
	02 - Steam Generation Plant	Manatee U1	31100	4.1%	56,430.25	56,430.25
	02 - Steam Generation Plant	Manatee U1	31200	4.8%	472,570.03	472,570.03
	02 - Steam Generation Plant	Manatee U2	31100	4.1%	56,332.75	56,332.75
	02 - Steam Generation Plant	Manatee U2	31200	4.0%	508,734.36	508,734.36
	02 - Steam Generation Plant	Martin Comm	31200	4.1%	31,631.74	31,631.74
	02 - Steam Generation Plant	Martin U1	31100	1.5%	36,810.86	36,810.86
	02 - Steam Generation Plant	Martin U1	31200	1.8%	521,075.17	521,075.17
	02 - Steam Generation Plant	Martin U2	31100	1.5%	36,845.37	36,845.37
	02 - Steam Generation Plant	Martin U2	31200	1.5%	519,484.96	519,484.96
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.7%	127,911.34	127,911.34
	02 - Steam Generation Plant	PtEverglades Comm	31200	2.2%	61,620.47	61,620.47
	02 - Steam Generation Plant	PtEverglades U1	31200	6.7%	453,661.22	453,661.22
	02 - Steam Generation Plant	PtEverglades U2	31200	6.1%	475,113.36	475,113.36
	02 - Steam Generation Plant	PtEverglades U3	31200	4.0%	503,968.62	503,968.62
	02 - Steam Generation Plant	PtEverglades U4	31200	3.6%	512,809.90	532,809.90
	02 - Steam Generation Plant	Riviera Comm	31100	1.9%	60,973.18	60,973.18
	02 - Steam Generation Plant	Riviera Comm	31200	0.4%	29,117.75	13,315.76
	02 - Steam Generation Plant	Riviera U3	31200	1.7%	449,392.38	449,392.38
	02 - Steam Generation Plant	Riviera U4	31200	1.4%	433,421.96	433,421.96
	02 - Steam Generation Plant	Sanford U3	31100	4.0%	54,282.08	54,282.08
	02 - Steam Generation Plant	Sanford U3	31200	3.6%	431,831.34	438,831.34
	02 - Steam Generation Plant	Scherer U4	31200	1.9%	515,653.32	515,653.32
	02 - Steam Generation Plant	SJRPP - Comm	31100	3.1%	43,193.33	43,193.33
	02 - Steam Generation Plant	SJRPP - Comm	31200	2.0%	66,188.18	66,188.18
	02 - Steam Generation Plant	SJRPP U1	31200	2.2%	107,594.02	107,594.02
	02 - Steam Generation Plant	SJRPP U2	31200	2.3%	107,562.94	107,562.94
	02 - Steam Generation Plant	Turkey Pt Comm Fsil	31100	2.3%	59,056.19	59,056.19
	02 - Steam Generation Plant	Turkey Pt Comm Fsil	31200	2.1%	29,110.85	29,110.85
	02 - Steam Generation Plant	Turkey Pt U1	31200	2.0%	546,534.15	546,534.15
	02 - Steam Generation Plant	Turkey Pt U2	31200	1.8%	505,638.44	505,638.44
	05 - Other Generation Plant	FtLauderdale Comm	34100	4.1%	58,859.79	58,859.79
	05 - Other Generation Plant	FtLauderdale Comm	34500	4.1%	34,502.21	34,502.21
	05 - Other Generation Plant	FtLauderdale U4	34300	5.0%	461,080.14	476,456.39
	05 - Other Generation Plant	FtLauderdale U5	34300	3.7%	471,313.47	485,313.47
	05 - Other Generation Plant	FtMyers U2 CC	34300	5.5%	106,324.08	106,324.08
	05 - Other Generation Plant	FtMyers U3 CC	34300	5.6%	2,635.22	0.00
	05 - Other Generation Plant	Martin U3	34300	5.8%	431,927.00	445,927.00
	05 - Other Generation Plant	Martin U4	34300	5.7%	421,026.31	435,026.31
	05 - Other Generation Plant	Martin U8	34300	5.5%	25,657.00	25,657.00
	05 - Other Generation Plant	FtLauderdale Comm	34100	4.1%	82,857.82	82,857.82
	05 - Other Generation Plant	FtLauderdale Comm	34300	6.3%	3,138.97	3,138.97
	05 - Other Generation Plant	Putnam U1	34300	5.2%	335,440.55	349,440.55
	05 - Other Generation Plant	Putnam U2	34300	5.4%	368,844.07	382,844.07
	05 - Other Generation Plant	Sanford U4	34300	5.6%	45,032.12	95,501.38
	05 - Other Generation Plant	Sanford U5	34300	5.7%	104,111.16	53,641.90
		Total For Project 03 - Continuous Emission Monitoring			12,613,845.87	12,721,784.91

Florida Power & Light Company
Environmental Cost Recovery Clause
2007 Annual Capital Depreciation Schedule

Project Number	Function	Plant Name	Plant Account	Depreciation Rate / Amortization Period	Actual 12/31/2006 Plant In Service	Estimated 12/31/2007 Plant In Service
04 - Clean Closure Equivalency Demonstration						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.7%	17,254.20	17,254.20
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.7%	19,812.30	19,812.30
	02 - Steam Generation Plant	Turkey Pt Comm Fsil	31100	2.3%	21,799.28	21,799.28
	Total For Project 04 - Clean Closure Equivalency Demonstration				58,865.78	58,865.78
05 - Maintenance of Above Ground Fuel Tanks						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.7%	901,636.88	901,636.88
	02 - Steam Generation Plant	Manatee Comm	31100	4.9%	3,111,263.35	3,111,263.35
	02 - Steam Generation Plant	Manatee Comm	31200	14.1%	174,543.23	174,543.23
	02 - Steam Generation Plant	Manatee U1	31200	4.8%	104,845.35	104,845.35
	02 - Steam Generation Plant	Manatee U2	31200	4.0%	127,429.19	127,429.19
	02 - Steam Generation Plant	Martin Comm	31100	1.7%	1,110,450.32	1,110,450.32
	02 - Steam Generation Plant	Martin U1	31100	1.5%	176,338.83	176,338.83
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.7%	1,132,078.22	1,132,078.22
	02 - Steam Generation Plant	Riviera Comm	31100	1.9%	1,081,354.77	1,081,354.77
	02 - Steam Generation Plant	Sanford U3	31100	4.0%	796,754.11	796,754.11
	02 - Steam Generation Plant	SJRPP - Comm	31100	3.1%	42,091.24	42,091.24
	02 - Steam Generation Plant	SJRPP - Comm	31200	2.0%	2,292.39	2,292.39
	02 - Steam Generation Plant	Turkey Pt Comm Fsil	31100	2.3%	87,560.23	87,560.23
	02 - Steam Generation Plant	Turkey Pt U2	31100	2.1%	42,158.96	42,158.96
	05 - Other Generation Plant	FtLauderdale Comm	34200	4.4%	898,110.65	898,110.65
	05 - Other Generation Plant	FtLauderdale GTs	34200	4.5%	584,290.23	584,290.23
	05 - Other Generation Plant	FtMyers GTs	34200	5.0%	68,893.65	68,893.65
	05 - Other Generation Plant	PtEverglades GTs	34200	5.1%	2,359,099.94	2,359,099.94
	05 - Other Generation Plant	Putnam Comm	34200	3.7%	749,025.94	749,025.94
	Total For Project 05 - Maintenance of Above Ground Fuel Tanks				13,550,217.48	13,550,217.48
07 - Relocate Turbine Lube Oil Piping						
	03 - Nuclear Generation Plant	StLucie U1	32300	1.2%	31,030.00	31,030.00
	Total For Project 07 - Relocate Turbine Lube Oil Piping				31,030.00	31,030.00
08 - Oil Spill Clean-up/Response Equipment						
	02 - Steam Generation Plant	Amortizable	31670	7-Yr	273,695.22	283,913.98
	02 - Steam Generation Plant	CapeCanaveral Comm	31600	2.8%	0.00	25,000.00
	02 - Steam Generation Plant	Martin Comm	31600	3.2%	23,107.32	23,107.32
	05 - Other Generation Plant	Amortizable	34670	7-Yr	45,699.54	45,699.54
	08 - General Plant	Amortizable	39130	7-Yr	0.00	35,000.00
	Total For Project 08 - Oil Spill Clean-up/Response Equipment				342,502.08	412,720.84
10 - Reroute Storm Water Runoff						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.4%	117,793.83	117,793.83
	Total For Project 10 - Reroute Storm Water Runoff				117,793.83	117,793.83
12 - Scherer Discharge Pipline						
	02 - Steam Generation Plant	Scherer Comm	31000	0.0%	9,936.72	9,936.72
	02 - Steam Generation Plant	Scherer Comm	31100	1.6%	524,872.97	524,872.97
	02 - Steam Generation Plant	Scherer Comm	31200	1.6%	328,761.62	328,761.62
	02 - Steam Generation Plant	Scherer Comm	31400	1.0%	689.11	689.11
	Total For Project 12 - Scherer Discharge Pipline				864,260.42	864,260.42
20 - Wastewater/Stormwater Discharge Elimination						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.7%	706,500.94	706,500.94
	02 - Steam Generation Plant	Martin U1	31200	1.8%	380,994.77	380,994.77
	02 - Steam Generation Plant	Martin U2	31200	1.5%	416,671.92	416,671.92
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.7%	296,707.34	296,707.34
	02 - Steam Generation Plant	Riviera Comm	31100	1.9%	560,786.81	560,786.81
	Total For Project 20 - Wastewater/Stormwater Discharge Elimination				2,361,661.78	2,361,661.78
21 - St. Lucie Turtle Nets						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.4%	828,789.34	828,789.34
	Total For Project 21 - St. Lucie Turtle Nets				828,789.34	828,789.34

Florida Power & Light Company
Environmental Cost Recovery Clause
2007 Annual Capital Depreciation Schedule

Project Number	Function	Plant Name	Plant Account	Depreciation Rate / Amortization Period	Actual 12/31/2006 Plant In Service	Estimated 12/31/2007 Plant In Service
23 - Spill Prevention Clean-Up & Countermeasures						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	1.7%	665,907.33	665,907.33
	02 - Steam Generation Plant	CapeCanaveral Comm	31400	0.7%	13,451.85	13,451.85
	02 - Steam Generation Plant	CapeCanaveral Comm	31500	1.9%	13,450.30	13,450.30
	02 - Steam Generation Plant	Cutler Comm	31400	0.0%	12,236.00	12,236.00
	02 - Steam Generation Plant	Cutler U5	31400	0.2%	18,388.00	18,388.00
	02 - Steam Generation Plant	Manatee Comm	31100	4.9%	95,458.00	336,763.43
	02 - Steam Generation Plant	Manatee Comm	31500	3.7%	5,000.00	5,000.00
	02 - Steam Generation Plant	PtEverglades Comm	31100	2.7%	10,379.00	10,379.00
	02 - Steam Generation Plant	Riviera Comm	31100	1.9%	205,014.03	205,014.03
	02 - Steam Generation Plant	Riviera U3	31200	1.7%	736,958.97	736,958.97
	02 - Steam Generation Plant	Riviera U4	31200	1.4%	894,298.77	894,298.77
	02 - Steam Generation Plant	Sanford U3	31100	4.0%	213,687.21	213,687.21
	02 - Steam Generation Plant	Sanford U3	31200	3.6%	211,727.22	211,727.22
	02 - Steam Generation Plant	Turkey Pt Comm Fsil	31500	2.1%	13,559.00	13,559.00
	03 - Nuclear Generation Plant	StLucie U1	32400	1.7%	0.00	437,209.61
	03 - Nuclear Generation Plant	StLucie U2	32300	1.9%	0.00	396,084.37
	05 - Other Generation Plant	Amortizable	34670	7-Yr	7,065.10	7,065.10
	05 - Other Generation Plant	FtLauderdale Comm	34100	4.1%	189,219.17	189,219.17
	05 - Other Generation Plant	FtLauderdale Comm	34200	4.4%	1,480,169.46	1,480,169.46
	05 - Other Generation Plant	FtLauderdale Comm	34300	1.8%	28,250.00	28,250.00
	05 - Other Generation Plant	FtLauderdale GTs	34100	2.2%	92,726.74	92,726.74
	05 - Other Generation Plant	FtLauderdale GTs	34200	4.5%	513,250.07	513,250.07
	05 - Other Generation Plant	FtMyers GTs	34100	2.1%	98,714.92	98,714.92
	05 - Other Generation Plant	FtMyers GTs	34200	5.0%	629,983.29	629,983.29
	05 - Other Generation Plant	FtMyers GTs	34500	2.9%	12,430.00	12,430.00
	05 - Other Generation Plant	FtMyers U2 CC	34300	5.5%	49,727.00	49,727.00
	05 - Other Generation Plant	FtMyers U3 CC	34500	4.8%	12,430.00	12,430.00
	05 - Other Generation Plant	Martin Comm	34100	3.4%	61,215.95	61,215.95
	05 - Other Generation Plant	PtEverglades GTs	34100	1.5%	454,080.68	454,080.68
	05 - Other Generation Plant	PtEverglades GTs	34200	5.1%	1,703,610.61	1,703,610.61
	05 - Other Generation Plant	Putnam Comm	34100	4.1%	148,511.20	148,511.20
	05 - Other Generation Plant	Putnam Comm	34200	3.7%	1,713,191.94	1,713,191.94
	05 - Other Generation Plant	Putnam Comm	34500	4.2%	60,746.93	60,746.93
	06 - Transmission Plant - Electric		35200	2.5%	951,562.91	951,562.91
	06 - Transmission Plant - Electric		35300	2.8%	177,981.88	177,981.88
	07 - Distribution Plant - Electric		36100	2.6%	2,862,088.65	2,862,093.44
	08 - General Plant		39000	2.7%	7,975.00	7,975.00
	Total For Project 23 - Spill Prevention Clean-Up & Countermeasures				**14,364,447.18**	**15,439,051.38**
24 - Manatee Reburn						
	02 - Steam Generation Plant	Manatee U1	31200	4.8%	15,479,973.76	17,690,083.30
	02 - Steam Generation Plant	Manatee U2	31200	4.0%	14,743,192.81	16,847,955.46
	Total For Project 24 - Manatee Reburn				**30,223,166.57**	**34,538,038.76**
25 - PPE ESP Technology						
	02 - Steam Generation Plant	PtEverglades U1	31200	6.7%	13,082,737.27	13,091,907.19
	02 - Steam Generation Plant	PtEverglades U1	31500	2.0%	418,393.78	418,687.04
	02 - Steam Generation Plant	PtEverglades U2	31200	6.1%	15,794,922.02	15,804,017.73
	02 - Steam Generation Plant	PtEverglades U2	31500	2.1%	638,102.67	638,470.14
	02 - Steam Generation Plant	PtEverglades U3	31100	2.6%	0.00	4,812,793.71
	02 - Steam Generation Plant	PtEverglades U3	31200	4.0%	0.00	16,125,920.25
	02 - Steam Generation Plant	PtEverglades U3	31500	2.2%	0.00	2,531,026.34
	02 - Steam Generation Plant	PtEverglades U4	31200	3.6%	0.00	25,326,653.05
	02 - Steam Generation Plant	PtEverglades U4	31500	2.1%	0.00	3,091,243.18
	Total For Project 25 - PPE ESP Technology				**29,934,155.74**	**81,840,718.63**
31 - Clean Air Interstate Rule (CAIR)						
	05 - Other Generation Plant	FtLauderdale GTs	34300	2.2%	0.00	132,333.00
	05 - Other Generation Plant	FtMyers GTs	34300	3.1%	0.00	132,333.00
	05 - Other Generation Plant	PtEverglades GTs	34300	2.6%	0.00	132,333.00
	Total For Project 31 - Clean Air Interstate Rule (CAIR)				**0.00**	**396,999.00**
	Total For All Projects				**122,799,944.57**	**180,635,325.32**

FLORIDA POWER & LIGHT COMPANY

Department of Environmental Protection
Drinking Water Standards, Monitoring, and Reporting

Rule 62-550.310, F.A.C.
Primary Drinking Water Standards: Maximum Contaminant Levels and Maximum Residual Disinfectant Levels

RRL-1
DOCKET NO. 070007-EI
FPL WITNESS: R.R. LABAUVE
EXHIBIT ___________
PAGES 1-3

62-550.310 Primary Drinking Water Standards: Maximum Contaminant Levels and Maximum Residual Disinfectant Levels.

(These standards may also apply as ground water quality standards as referenced in Chapter 62-520, F.A.C.)

(1) INORGANICS – Except for nitrate and nitrite, which apply to all public water systems, this subsection applies to community water systems and non-transient non-community water systems only.

(a) The maximum contaminant levels for the inorganic contaminants are listed in Table 1, which is incorporated herein and appears at the end of this chapter.

(b) The maximum contaminant level for nitrate (as N) applicable to transient non-community water systems is 10 milligrams per liter. The Department or Approved County Health Department shall allow a contaminant level for nitrate (as N) of up to 20 milligrams per liter upon a showing by the supplier of water that the following conditions are met:

1. The water distributed by the water system is not available to children under 6 months of age or to lactating mothers, and

2. There is continuous public notification of what the nitrate level (as N) is and what the potential health effects of such exposure are.

3. The Department shall require monitoring every 3 months as long as the maximum contaminant level is exceeded. Should adverse health effects occur, the Department shall require immediate compliance with the maximum contaminant level for nitrate (as N).

(c) The revised maximum contaminant level of 0.010 mg/L for arsenic becomes effective January 1, 2005. All community and non-transient non-community water systems shall demonstrate compliance with the revised maximum contaminant level by December 31, 2007.

(2) DISINFECTANT RESIDUALS – Except for the chlorine dioxide maximum residual disinfectant level, which applies to all public water systems using chlorine dioxide as a disinfectant or oxidant, this subsection applies only to community or non-transient non-community water systems adding a chemical disinfectant to the water in any part of the drinking water treatment process. Maximum residual disinfectant levels (MRDLs) are listed in Table 2, which is incorporated herein and appears at the end of this chapter.

(3) DISINFECTION BYPRODUCTS – This subsection applies to all community or non-transient non-community water systems adding a chemical disinfectant to the water in any part of the drinking water treatment process. The Stage 1 maximum contaminant levels (MCLs) for disinfection byproducts are listed in Table 3, which is incorporated herein and appears at the end of this chapter.

(4) ORGANICS – This subsection applies only to community water systems and non-transient non-community water systems.

(a) The maximum contaminant levels for the volatile organic contaminants (VOCs) are listed in Table 4, which is incorporated herein and appears at the end of this chapter. The regulatory detection limit (RDL) for all VOCs is 0.0005 mg/L.

(b) The maximum contaminant levels and the regulatory detection limits (RDLs) for the synthetic organic contaminants (SOCs) are listed in Table 5, which is incorporated herein and appears at the end of this chapter.

(5) MICROBIOLOGICAL – This subsection applies to all public water systems. Monitoring requirements to demonstrate compliance with this subsection are defined in Rule 62-550.518, F.A.C.

(a) The maximum contaminant level is based on the presence or absence of total coliforms in a sample, rather than coliform density. For the purposes of the public notice requirements in Rule 62-560.410, F.A.C., a violation of the standards in this paragraph poses a non-acute risk to health.

1. For a system which collects at least 40 samples per month, if no more than 5.0 percent of the samples collected during a month are total coliform-positive, the system is in compliance with the maximum contaminant level for total coliforms.

2. For a system which collects fewer than 40 samples per month, if no more than one sample collected during a month is total coliform-positive, the system is in compliance with the maximum contaminant level for total coliforms.

(b) Any fecal coliform-positive repeat sample or *E. coli*-positive repeat sample, or any total coliform-positive repeat sample following a fecal coliform-positive or *E. coli*-positive routine sample is a violation of the maximum contaminant level for total coliforms. For the purposes of the public notification requirements in Rule 62-560.410, F.A.C., this is a violation that poses an acute risk to health.

(c) A public water system shall determine compliance with the maximum contaminant level for total coliforms in paragraphs (a) and (b) of this subsection for each month (or quarter for transient non-community water systems that use only ground water not under the direct influence of surface water and that serve 1,000 or fewer persons) in which it is required to monitor for total coliforms.

(6) RADIONUCLIDES – This subsection applies only to community water systems. The following are the maximum contaminant levels (MCLs) and regulatory detection limits (RDLs) for radionuclides:

(a) Naturally occurring radionuclides:

MAXIMUM CONTAMINANT LEVELS
FOR RADIONUCLIDES

CONTAMINANT	MAXIMUM CONTAMINANT LEVEL
Combined radium226 and radium228	5 pCi/L
Gross alpha particle activity including radium226 but excluding radon and uranium	15 pCi/L
Uranium	30 ug/L

pCi/L = picoCuries per liter
ug/L = micrograms per liter

(b) Man-made radionuclides:

1. The average annual concentration of beta particle and photon radioactivity from man-made radionuclides in drinking water shall not produce an annual dose equivalent to the body or any internal organ greater than 4 millirem/year.

2. Except for those radionuclides listed below, the concentration of man-made radionuclides causing 4 mrem total body or organ dose equivalents shall be calculated on the basis of a 2 liter per day drinking water intake using the 168-hour data list in "Maximum Permissible Body Burdens and Maximum Permissible Concentration of Radionuclides in Air or Water for Occupational Exposure," NBS Handbook 69 as amended August 1963, U. S. Department of Commerce.

Average Annual Concentration Assumed to Produce
an Exposure of 4 millirem/year:

RADIONUCLIDE	CRITICAL ORGAN	pCi/L
Tritium	total body	20,000
Strontium90	bone marrow	8

pCi/L = picoCuries per liter

3. If two or more radionuclides are present, the sum of their annual dose equivalent to the total body or to any organ shall not exceed 4 millirem/year.

(c) For the purposes of monitoring for gross alpha particle activity, radium-226, radium-228, uranium, and beta particle and photon radioactivity in drinking water, the following regulatory detection limits shall be used:

CONTAMINANT	REGULATORY DETECTION LIMIT
Gross alpha particle activity	3 pCi/L
Radium-226	1 pCi/L
Radium-228	1 pCi/L
Uranium	1 ug/L
Tritium	1,000 pCi/L
Strontium-89	10 pCi/L
Strontium-90	2 pCi/L
Iodine-131	1 pCi/L
Cesium-134	10 pCi/L
Gross beta	4 pCi/L
Other radionuclides	1/10 of the applicable limit

pCi/L = picoCuries per liter
ug/L = micrograms per liter

Specific Authority 403.861(9) FS. Law Implemented 403.852(12), 403.853(1) FS. History–New 11-19-87, Formerly 17-22.210, Amended 1-18-89, 5-7-90, 1-3-91, 1-1-93, 1-26-93, 7-4-93, Formerly 17-550.310, Amended 9-7-94, 8-1-00, 11-27-01, 4-14-03, 4-25-03, 11-28-04.

FLORIDA POWER & LIGHT COMPANY

Consent Order
in OGC Case Number 06-0744
FPL Martin Plant Public Water System
PWS #4431748

RRL-2
DOCKET NO. 070007-EI
FPL WITNESS: R.R. LABAUVE
EXHIBIT ___________
PAGES 1-11

Department of Environmental Protection

Southeast District
400 N. Congress Avenue, Suite 200
West Palm Beach, Florida 33401

Jeb Bush
Governor

Colleen M. Castille
Secretary

SEP 22 2006

CERTIFIED MAIL #7006 0100 0002 8783 9555
RETURN RECEIPT REQUESTED

Craig Arcari, General Manager
Florida Power & Light Company – Martin Plant
P.O. Box 176
Indiantown, Florida 34954

Re: Consent Order in OGC Case Number 06-0744
FPL Martin Plant Public Water System PWS #4431748

Dear Mr. Arcari:

Enclosed for your implementation is the fully executed and filed Consent Order in the above-styled case. Please familiarize yourself with the compliance dates and terms of the Consent Order so the complete and timely performance of those obligations is accomplished.

Thank you for your cooperation in this matter. If you have any questions concerning the Consent Order, please contact **Michele Owens** of this office at 561/681-6700.

Sincerely,

Kevin R. Neal 9/22/06

Kevin R. Neal Date
District Director
Southeast District Office
KRN/LAH/TRB/mo

Enclosure (all)

cc: Jerry Toney – Drinking Water Compliance Section, DEP/PSL
Lea Crandall – OGC, MS-35, DEP/Tallahassee

BEFORE THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION,	IN THE OFFICE OF THE SOUTHEAST DISTRICT
Complainant,	OGC FILE NO. 06-0744
vs.	
FLORIDA POWER & LIGHT COMPANY,	
Respondent.	

CONSENT ORDER

This Consent Order is entered into between the State of Florida Department of Environmental Protection ("Department") and Florida Power & Light Company ("Respondent") to reach settlement of certain matters at issue between the Department and Respondent.

The Department finds and the Respondent neither admits nor denies the following:

1. The Department is the administrative agency of the State of Florida having the power and duty to protect Florida's air and water resources and to administer and enforce the provisions of the Florida Safe Drinking Water Act, Sections 403.850 et seq., Florida Statutes, and the rules promulgated thereunder, Title 62, Florida Administrative Code. The Department has jurisdiction over the matters addressed in this Consent Order.

2. Respondent is a "person" within the meaning of Section 403.852(5), Florida Statutes.

3. Respondent is the owner and is responsible for the operation of a nontransient noncommunity public water system ("System"), PWS #4431748, located on Warfield Boulevard, northwest of Indiantown, Martin County, Florida, which serves the Florida Power & Light Martin Power Plant.

4. The Department finds that Respondent is in violation of Rule 62-550.310(3), Fla. Admin. Code which establishes the maximum contaminant levels (MCLs) for total

trihalomethanes (TTHMs) and haloacetic acids (five) (HAA5s) as 0.080 milligrams per liter (mg/L) and 0.060 mg/L, respectively. The average results for samples collected from the System on March 15, 2005, April 12, 2005, September 14, 2005, and December 28, 2005, and analyzed for total trihalomethanes (TTHMs) and haloacetic acids (five) (HAA5s) are 0.173 milligrams per liter (mg/L) and 0.132 mg/L, respectively.

Having reached a resolution of the matter the Department and the Respondent mutually agree and it is

ORDERED:

5. Respondent shall comply with the following corrective actions within the stated time periods:

a. By September 1, 2006, Respondent shall retain the services of a Florida-registered professional engineer to evaluate the System and either submit an application, along with any required application fees, to the Department for a permit to construct any modifications needed to address the MCL exceedances, or, if the evaluation determines that no additional treatment is needed, a plan of corrective action ("Plan") with interim milestone dates, signed and sealed by a Florida-registered Professional Engineer.

b. The Department shall review the application/Plan submitted pursuant to paragraph 5.a. above. In the event additional information, modifications or specifications are necessary to process the application/Plan, the Department shall issue a written request for information ("RFI") to Respondent for such information. Respondent shall accordingly submit the requested information in writing to the Department within 30 days of receipt of the request. Respondent shall provide all information requested in any additional RFIs issued by the Department within 30 days of receipt of each request. Within 60 days of the date the Department receives the application/Plan pursuant to paragraph 5.a. above, Respondent shall provide all information necessary to complete the application/Plan. The Department shall notify Respondent in writing of Department approval of the Plan.

c. Within 180 days of issuance of any required permit(s), or written Department approval, if no permit is required, Respondent shall complete the Department-approved modifications in accordance with the permit/written approval issued pursuant to paragraphs 5.a. and 5.b. above, and submit to the Department the engineer's certification of completion of construction, along with all required supporting documentation. Respondent shall receive written Department clearance prior to placing the System modifications into service.

d. Respondent shall continue to sample quarterly for TTHMs and HAA5s. Results shall be submitted to the Department within ten (10) days of Respondent's receipt of the results.

e. In the event that the modifications approved by the Department pursuant to paragraphs 5.a. and b. are determined to be inadequate to resolve the MCL exceedances, the Department will notify the Respondent in writing. Within 30 days of receipt of written notification from the Department that the results of the quarterly sampling indicate that the System modifications have not resolved the violations, Respondent shall submit another proposal to address the MCL exceedances. Respondent shall provide all information requested in any RFIs issued by the Department within 30 days of receipt of each request. Within 60 days of the date the Department receives the application pursuant to this paragraph, Respondent shall provide all information necessary to complete the application.

f. Within two years of the effective date of this Consent Order, Respondent shall complete all corrective actions needed to resolve the MCL exceedances and submit written certification of completion to the Department for all modifications.

g. Respondent shall continue to issue public notice regarding the MCL exceedances every 90 days in accordance with Rule 62-560.410(1), Fla. Admin. Code, until the Department determines that System is in compliance with all MCLs. Respondent shall submit certification of delivery of public notice, using DEP Form 62-555.900(22), to the Department within ten days of issuing each public notice.

6. Within 30 days of the effective date of this Consent Order, Respondent shall reimburse the Department for costs and expenses in the amount of $500.00 which were incurred by the Department during the investigation of this matter and the preparation and tracking of this Consent Order. Payment shall be made by cashier's check or money order. The instrument shall be made payable to the "Department of Environmental Protection" and shall include thereon the OGC number assigned to this Consent Order and the notation "Ecosystem Management and Restoration Trust Fund."

7. Respondent agrees to pay the Department stipulated penalties in the amount of $100.00 per day for each and every day Respondent fails to timely comply with any of the requirements of paragraphs 5 and 6 of this Consent Order. A separate stipulated penalty shall be assessed for each violation of this Consent Order. Within 30 days of written demand from the Department, Respondent shall make payment of the appropriate stipulated penalties to "The Department of Environmental Protection" by cashier's check or money order and shall include the OGC number assigned to this Consent Order and the notation "Ecosystem Management and Restoration Trust Fund". Payment shall be sent to the Department of Environmental Protection, 400 North Congress Avenue, Suite 200, West Palm Beach, FL 33401. The Department may make demands for payment at any time after violations occur. Nothing in this paragraph shall prevent the Department from filing suit to specifically enforce any of the terms of this Consent Order. Any penalties assessed under this paragraph shall be in addition to the $500.00 agreed to in paragraph 6 of this Consent Order.

8. If any event, including administrative or judicial challenges by third parties unrelated to the Respondent, occurs which causes delay or the reasonable likelihood of delay, in complying with the requirements of this Consent Order, Respondent shall have the burden of proving the delay was or will be caused by circumstances beyond the reasonable control of the Respondent and could not have been or cannot be overcome by Respondent's due diligence. Economic circumstances shall not be considered circumstances beyond the control of Respondent, nor shall the failure of a contractor, subcontractor, materialman or other agent

(collectively referred to as "contractor") to whom responsibility for performance is delegated to meet contractually imposed deadlines be a cause beyond the control of Respondent, unless the cause of the contractor's late performance was also beyond the contractor's control. Upon occurrence of an event causing delay, or upon becoming aware of a potential for delay, Respondent shall notify the Department's Southeast District Office in West Palm Beach orally within 72 hours or within three working days and shall, within ten calendar days of oral notification to the Department, notify the Department in writing of the anticipated length and cause of the delay, the measures taken or to be taken to prevent or minimize the delay and the timetable by which Respondent intends to implement these measures. If the parties can agree that the delay or anticipated delay has been or will be caused by circumstances beyond the reasonable control of Respondent, the time for performance of one or more of the requirements hereunder shall be extended for a period equal to the agreed delay resulting from such circumstances. Such agreement shall adopt all reasonable measures necessary to avoid or minimize delay. Failure of Respondent to comply with the notice requirements of this Paragraph in a timely manner shall constitute a waiver of Respondent's right to request an extension of time for compliance with the requirements of this Consent Order.

9. Persons who are not parties to this Consent Order, but whose substantial interests are affected by this Consent Order, have a right, pursuant to Sections 120.569 and 120.57, Florida Statutes, to petition for an administrative hearing on it. The Petition must contain the information set forth below and must be filed (received) at the Department's Office of General Counsel, 3900 Commonwealth Boulevard, MS# 35, Tallahassee, Florida 32399-3000 within 21 days of receipt of this notice. A copy of the Petition must also be mailed at the time of filing to the District Office named above at the address indicated. Failure to file a petition within the 21 days constitutes a waiver of any right such person has to an administrative hearing pursuant to Sections 120.569 and 120.57, Florida Statutes.

10. The petition shall contain the following information:

a. The name, address, and telephone number of each petitioner; the Department's Consent Order identification number and the county in which the subject matter or activity is located;

b. A statement of how and when each petitioner received notice of the Consent Order;

c. A statement of how each petitioner's substantial interests are affected by the Consent Order;

d. A statement of the material facts disputed by petitioner, if any;

e. A statement of facts which petitioner contends warrant reversal or modification of the Consent Order;

f. A statement of which rules or statutes petitioner contends require reversal or modification of the Consent Order;

g. A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Consent Order.

11. If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this Notice. Persons whose substantial interests will be affected by any decision of the Department with regard to the subject Consent Order have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 21 days of receipt of this notice in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Sections 120.569 and 120.57, Florida Statutes, and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-106.205, Florida Administrative Code.

12. A person whose substantial interests are affected by the Consent Order may file a timely petition for an administrative hearing under Sections 120.569 and 120.57, Florida

Statutes, or may choose to pursue mediation as an alternative remedy under Section 120.573, Florida Statutes, before the deadline for filing a petition. Choosing mediation will not adversely affect the right to a hearing if mediation does not result in a settlement. The procedures for pursuing mediation are set forth below.

13. Mediation may only take place if the Department and all the parties to the proceeding agree that mediation is appropriate. A person may pursue mediation by reaching a mediation agreement with all parties to the proceeding (which include the Respondent, the Department, and any person who has filed a timely and sufficient petition for a hearing) and by showing how the substantial interests of each mediating party are affected by the Consent Order. The agreement must be filed in (received by) the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, MS #35, Tallahassee, Florida 32399-3000, within 10 days after the deadline as set forth above for the filing of a petition.

14. The agreement to mediate must include the following:

a. The names, addresses, and telephone numbers of any persons who may attend the mediation;

b. The name, address, and telephone number of the mediator selected by the parties, or a provision for selecting a mediator within a specified time;

c. The agreed allocation of the costs and fees associated with the mediation;

d. The agreement of the parties on the confidentiality of discussions and documents introduced during mediation;

e. The date, time, and place of the first mediation session, or a deadline for holding the first session, if no mediator has yet been chosen;

f. The name of each party's representative who shall have authority to settle or recommend settlement;

g. Either an explanation of how the substantial interests of each mediating party will be affected by the action or proposed action addressed in this notice of intent or a statement clearly identifying the petition for hearing that each party has already filed, and incorporating it by reference; and

h. The signatures of all parties or their authorized representatives. As provided in Section 120.573, Florida Statutes, the timely agreement of all parties to mediate will toll the time limitations imposed by Sections 120.569 and 120.57, Florida Statutes, for requesting and holding an administrative hearing. Unless otherwise agreed by the parties, the mediation must be concluded within sixty days of the execution of the agreement. If mediation results in settlement of the administrative dispute, the Department must enter a final order incorporating the agreement of the parties. Persons whose substantial interests will be affected by such a modified final decision of the Department have a right to petition for a hearing only in accordance with the requirements for such petitions set forth above, and must therefore file their petitions within 21 days of receipt of this notice. If mediation terminates without settlement of the dispute, the Department shall notify all parties in writing that the administrative hearing processes under Sections 120.569 and 120.57, Florida Statutes, remain available for disposition of the dispute, and the notice will specify the deadlines that then will apply for challenging the agency action and electing remedies under those two statutes.

15. Respondent shall allow all authorized representatives of the Department access to the facility at reasonable times for the purpose of determining compliance with the terms of this Consent Order and the rules and statutes of the Department.

16. All submittals and payments required by this Consent Order to be submitted to the Department shall be sent to the Florida Department of Environmental Protection, Southeast District Water Facilities Program, 400 North Congress Avenue, Suite 200, West Palm Beach, Florida, 33401.

17. This Consent Order is a settlement of the Department's civil and administrative authority arising under Florida law to resolve the matters addressed herein. This Consent Order is not a settlement of any criminal liabilities, which may arise under Florida law, nor is it a

settlement of any violation which may be prosecuted criminally or civilly under federal law and which Respondent may defend.

18. The Department hereby expressly reserves the right to initiate appropriate legal action to prevent or prohibit any violations arising after the date of this Consent Order of applicable statutes, or the rules promulgated thereunder that are not specifically addressed by the terms of this Consent Order.

19. The terms and conditions set forth in this Consent Order may be enforced in a court of competent jurisdiction pursuant to Sections 120.69 and 403.121, Florida Statutes. Failure to comply with the terms of this Consent Order shall constitute a violation of Section 403.859, Florida Statutes.

20. The Department, for and in consideration of the complete and timely performance by Respondent of the obligations agreed to in this Consent Order, hereby waives its right to seek judicial imposition of damages or civil penalties for alleged violations.

21. Respondent is fully aware that a violation of the terms of this Consent Order may subject Respondent to judicial imposition of damages, civil penalties up to $5,000.00 per day per violation, and criminal penalties, except as limited by the provisions of this Consent Order.

22. Except as otherwise provided herein, entry of this Consent Order does not relieve Respondent of the need to comply with applicable federal, state or local laws, regulations or ordinances.

23. No modifications of the terms of this Consent Order shall be effective until reduced to writing and executed by both Respondent and the Department.

24. Respondent acknowledges and waives its right to an administrative hearing pursuant to Sections 120.569 and 120.57, Florida Statutes, on the terms of this Consent Order. Respondent acknowledges its right to appeal the terms of this Consent Order pursuant to Section 120.68, Florida Statutes, and waives that right upon signing this Consent Order.

25. This Consent Order is a final order of the Department pursuant to Section 120.52(7), Florida Statutes, and it is final and effective on the date filed with the Clerk of the

Department unless a Petition for Administrative Hearing is filed in accordance with Chapter 120, Florida Statutes. Upon the timely filing of a petition this Consent Order will not be effective until further order of the Department.

FOR THE RESPONDENT:

Craig W Arcari 8/31/2006

Craig Arcari, General Manager Date
Florida Power & Light Company - Martin Plant
P.O. Box 176
Indiantown, Florida 34954

DONE AND ORDERED this 22 day of Sept., 2006, in West Palm Beach, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Kevin R. Neal 9/22/06

Kevin R. Neal Date
District Director
Southeast District

FILED, on this date, pursuant to §120.52 Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Linda Tschappat 9-22-06

Clerk **Date**

Copies furnished to:
Lea Crandall, Agency Clerk, MS 35
Drinking Water Compliance Section, FDEP/PSL

FLORIDA POWER & LIGHT COMPANY

Golder Associates Inc.
FPL Martin Plant
Potable Water System
DBP (THM & HAA5) Analysis

RRL-3
DOCKET NO. 070007-EI
FPL WITNESS: R.R. LABAUVE
EXHIBIT __________
PAGES 1-107

Golder Associates Inc.
3730 Chamblee Tucker Road
Atlanta, GA USA 30341
Telephone (770) 496-1893
Fax (770) 934-9476

Golder Associates

August 29,2006

063-3495

FPL Martin Plant
PO Box 176
Indiantown FL 34956

Attn: Willie J. Welch, Production Support - Chemistry/ Environmental Leader

**RE: FPL MARTIN PLANT
POTABLE WATER SYSTEM
DBP (THM & HAA5) ANALYSIS**

Dear Willie:

Golder Associates Inc. (Golder) is pleased to send you this final report to provide recommendations as to how to achieve compliance with the drinking water limits for trihalomethanes and haloacetic acids within the Martin Plant potable water system.

Very truly yours,

GOLDER ASSOCIATES INC.

James J Daly

James J. Daly, P.E
Associate

Harold A Frediani, Jr.

Harold A. Frediani, Jr., P.E., P.H.
Senior Water Resources Engineer

JJCP/sdp

Florida P.E. Number 36394
Certificate of Authorization No. 1670

Attachments

HAROLD A. FREDIANI, JR.
LICENSE
No. 36394
STATE OF
FLORIDA
PROFESSIONAL ENGINEER

X:\Clients\Florida Power and Light\063-3495-Martin DBPs\Report\MartinDBPReport8-27-06.doc

1.0 INTRODUCTION

FPL retained Golder to assist in analyzing the Martin Plant potable water treatment system to assist FPL with compliance with Florida Department of Environmental Protection (FDEP) drinking water limits on Disinfection Byproducts (DBPs). Golder has performed a site visit to inspect the potable water system, reviewed well data, performed a literature search, and provided recommendations as to how to achieve compliance with the drinking water limits for trihalomethanes and haloacetic acids. This report documents the results of those tasks, and includes a corrective action plan, in the form of project milestones suitable for submittal to FDEP in response to their Consent Order.

2.0 BACKGROUND

The Martin potable water system serves Units 1 through 4 of the FPL Martin Plant, located in Indiantown, Florida. The original system was built with Units 1 and 2, and is depicted on the system Operational Manual drawings which are shown in Appendix A. A simplified flow diagram is shown in Figure 1. Water is pumped from the well through a static mixer in which liquid sodium hypochlorite is applied. The water then enters a multiple tray aerator. At the bottom of the aerator, the water is collected in the aerator tank, from which it is pumped in parallel to three mixed media (gravel, garnet, sand and anthracite) filters. From the filters, a portion of the water can be sent through softeners; however, most of the time all of the water is sent on to the activated carbon filter. From the carbon filter, the water is sent to the 15,000 gallon holding tank. Liquid sodium hypochlorite is injected directly into the holding tank. A recirculation pump is energized all the time to pressurize the distribution system to 70 psi; this pump recycles water back to the holding tank when necessary.

When Units 3 and 4 were added, the system was extended, and another pump, hydro-pneumatic tank, and sodium hypochlorite injection system were added.

The system currently is experiencing difficulty meeting the Disinfection Byproduct Rule (62-550 FAC, Table 3), which limits the level of Total Trihalomethanes (TTHM) to no more than 80 ug/L and HaloAcetic Acids Five (HAA5) to no more than 60 ug/L. FPL provided data taken since the DBP rule went into effect. The data are presented in Table 1. All but one of the samples were taken at the Maximum Residence Time (MRT) location, which is in the Units 3&4 laboratory building. The other sample was taken at the Point of Entry (POE) to the distribution system., which is at the outlet to the holding tank.

The TTHM data, along with the standard of 80 ug/L, are plotted in Figure 2. These data indicate that virtually all of the TTHM in the system is in the form of chloroform. The HAA5 data, along with the standard of 60 ug/L, are plotted in Figure 3. These data indicate that virtually all of the HAA5 is in the form of either di- or tri-chloroacetic acid (DCA or TCA). These findings are consistent with the disinfectant being used, which does not contain bromine, but has as the active disinfectant hypochlorite ion ($HClO_3^-$).

Figure 4 plots the three contributory compounds as a function of the disinfectant residual. Based on these data, it can be concluded that the DBP levels are not a function of the disinfection residual level. Therefore, it can be surmised that they are a function of the raw water organic content level.

FPL is in receipt of a proposed Consent Order (CO, see Appendix B) from FDEP to determine whether any modifications to the system are necessary, or whether the existing system can be corrected to achieve compliance. If modifications are necessary, the CO requires FPL to submit an application to modify the existing permit. If modifications are not necessary, the CO requires that FPL submit a plan of corrective action ("Plan") with interim milestone dates, signed and sealed by a Florida-registered Professional Engineer.

3.0 DISCUSSION

3.1 Existing Equipment

Within the existing system, there are only two mechanisms for removal of either DBPs or the DBP precursors (organic compounds). The aerator is intended to strip volatile organics out of the water, while the activated carbon filter removes them by adsorption. Since the aerator is the first of these processes that the influent water encounters, it appears that the aerator could accomplish sufficient treatment to achieve the required reduction in concentration of chloroform which is considered volatile. The aerator would not be expected to remove the DCA and TCA as well since they are reported to be of low volatility; however, some removal should be accomplished. A preliminary calculation (see Appendix C. Calculations) indicates that the aerator should work well if it's blower provides about 200 cubic feet per minute of air. Neither the plant operating manual, nor examination of the equipment, gives any indication of the original design capacity of the aerator. A necessary step in the future will be to measure the air flow through the aerator.

The carbon filter can be expected to remove all three of the compounds in question. Based on the flow rate, chloroform content, and size of the unit (39 cubic feet), an Empty Bed Contact time (EBCT) of 5.8 minutes has been calculated. This is borderline relative to AWWA recommendations of 5 to 25 minutes. However, two options are available to increase the EBCT using existing equipment. The first option would be to convert one or both of the softeners to contain activated carbon. The softeners are approximately 2 feet in diameter and 3 feet high, with an estimated volume of about 19 cubic feet between them. The second option would be to replace the anthracite media in the multi-media filters with activated carbon. Each filter contains about 7 cubic feet of anthracite, for a total of 14 cubic feet.. Using both of these options would increase the EBCT to about 11 minutes. Another option would be to inject powdered activated carbon (PAC) into the aerator tank, to adsorb the TTHMs and HAA5s and then be removed in the multi-media filters.

3.2 Alternative Disinfectants

Potential alternative disinfectants are chlorine dioxide, ultraviolet light, and ozone. Chlorine dioxide does not produce TTHMs, but produces chlorite, which is also regulated under the DBP rule. Ozone or UV can not be used because neither leaves a residual, which is required in a distribution system. In general, switching to an alternative disinfectant would not be expected to be as effective as improving the existing treatment system.

3.3 New Equipment

Either the aerator or the carbon filter could be replaced with newer, larger versions of the same equipment. Neither the carbon filter nor the aerator were sized when DBPs were a concern, and could certainly be replaced with larger units. This would provide the advantage of longer contact time.

4.0 CONCLUSIONS AND RECOMMENDATIONS

The literature review indicates (See Appendix C. Calculations for references) that the two DBP treatment technologies within the Martin system, namely aeration and activated carbon filtration, are presently the best technologies for the removal of DBPs. Therefore, it is concluded that no additional treatment technology is necessary, and the existing system needs corrective action to achieve the applicable limits. The first activity that should be undertaken is to perform measurements on the aerator to determine whether it is sized correctly and is working properly. Golder recommends that the following actions be taken:

- Measure the dimensions of the aerator column and stack;
- Measure the air velocity leaving the aerator when it is operating;
- Sample and analyze the inlet and outlet water at the aerator for TTHM and HAA5 to determine its removal performance; and
- Sample and analyze for TTHM and HAA5 the inlet and outlet water at the carbon filter, synoptically with the aerator water measurements.

Based on the results of the first three above actions, it can be determined whether the aerator can be enhanced or replaced to accomplish the desired water quality. Results from the fourth action can likewise be used to determine whether additional activated carbon EBCT would be helpful, and if so, how much would be required to be added, either in conjunction with improved aeration or instead of it.

5.0 PLAN AND MILESTONE DATES

This plan with milestone dates is predicated on the longest anticipated schedule and assumes that FDEP will issue one request for additional information, and that the measurements taken will lead to the ultimate decision to replace both the aerator and the carbon filter with new equipment. The interim milestone dates are as follows:

- September 1, 2006 - FPL submits signed Consent Order and signed/sealed corrective action plan;
- September 22, 2006 – FDEP issues written request for additional information (RFI);
- October 23, 2006 – FPL provides additional information to FDEP;
- October 30, 2006 – FDEP issues written approval of the plan;
- November 22, 2006 – FPL completes measurements of physical characteristics of aeration system, and takes synoptic samples of inlet and outlet water for both the aerator and the carbon filter, and sends those samples to the laboratory;
- December 6, 2006 – FPL receives results/report from laboratory;
- January 31, 2007 – Install pilot equipment for testing;
- September 30, 2007 – Complete testing of pilot;
- October 1, 2007 - FPL issues performance specifications to bidders to provide new aerator and carbon filter units;
- November 1, 2007 – FPL receives bids to provide new aerator and carbon filter units;
- December 1, 2007 - FPL awards contract to successful bidder to install new aerator and carbon filter units;
- January 2008 - Installation of new aerator and carbon filter units is complete;
- June 2008 - Testing of new aerator and carbon filter units is complete, FPL submits engineer's certification of completion of construction and required supporting documentation.
- July 2008 - FDEP issues written clearance to place the system modifications into service.

TABLES

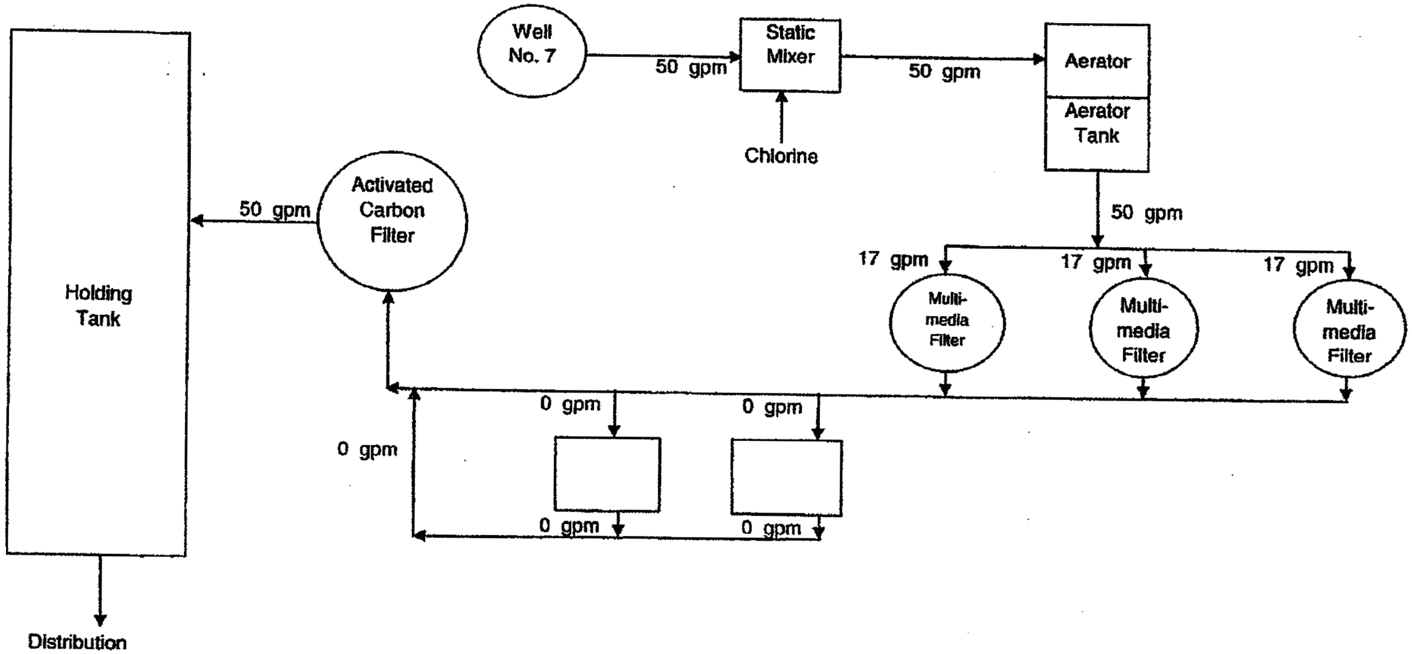
Table 1. Monitoring Data

Location	MRT	MRT	MRT	MRT	MRT	MRT	Potable POE
Date	5/25/2006	2/13/2006	12/21/2005	9/14/2005	4/12/2005	3/15/2005	8/25/2004
Monochloroacetic acid - ug/L	0.9	2.8	4	4.7	4.9	0.9	5.3
Dichloroacetic acid - ug/L	46.4	59	54	100	87	33	120
Trichloroacetic acid - ug/L	50.9	41	43	99	64	29	100
Monobromoacetic acid - ug/L	0.28	0.46	0.3	0.5	0.28	0.28	0.28
Dibromoacetic acid - ug/L	0.235	2.6	1.2	0.52	0.8	0.47	1.3
HAA5 - ug/L	97.3	105	100	210	160	63	230
HAAF Standard - ug/L	60	60	60	60	60	60	60
Date	5/25/2006	2/13/2006	12/21/2005	9/14/2005	4/12/2005	3/15/2005	8/25/2004
Chloroform - ug/L	123	160	140	210	160	70	250
Bromoform - ug/L	0.205	0.205	0.205	0.205	0.205	0.205	0.205
Bromodichloromethane - ug/L	27.5	46	23	32	32	13	37
Dibromochloromethane - ug/L	5.02	11	2.5	3.3	3.7	1.4	3.9
TTHM - ug/L	155	210	160	240	190	84	290
TTHM Standard - ug/L	80	80	80	80	80	80	80
Chlorine residual		0.6	1.2	0.4	0.4	1.1	

FIGURES

Notes: Flows in gpm shown when pump is on.

Figure 1. Martin Potable Water Flow Diagram



8/18/2006 4:03 PM

Figures.xls Fgure 1

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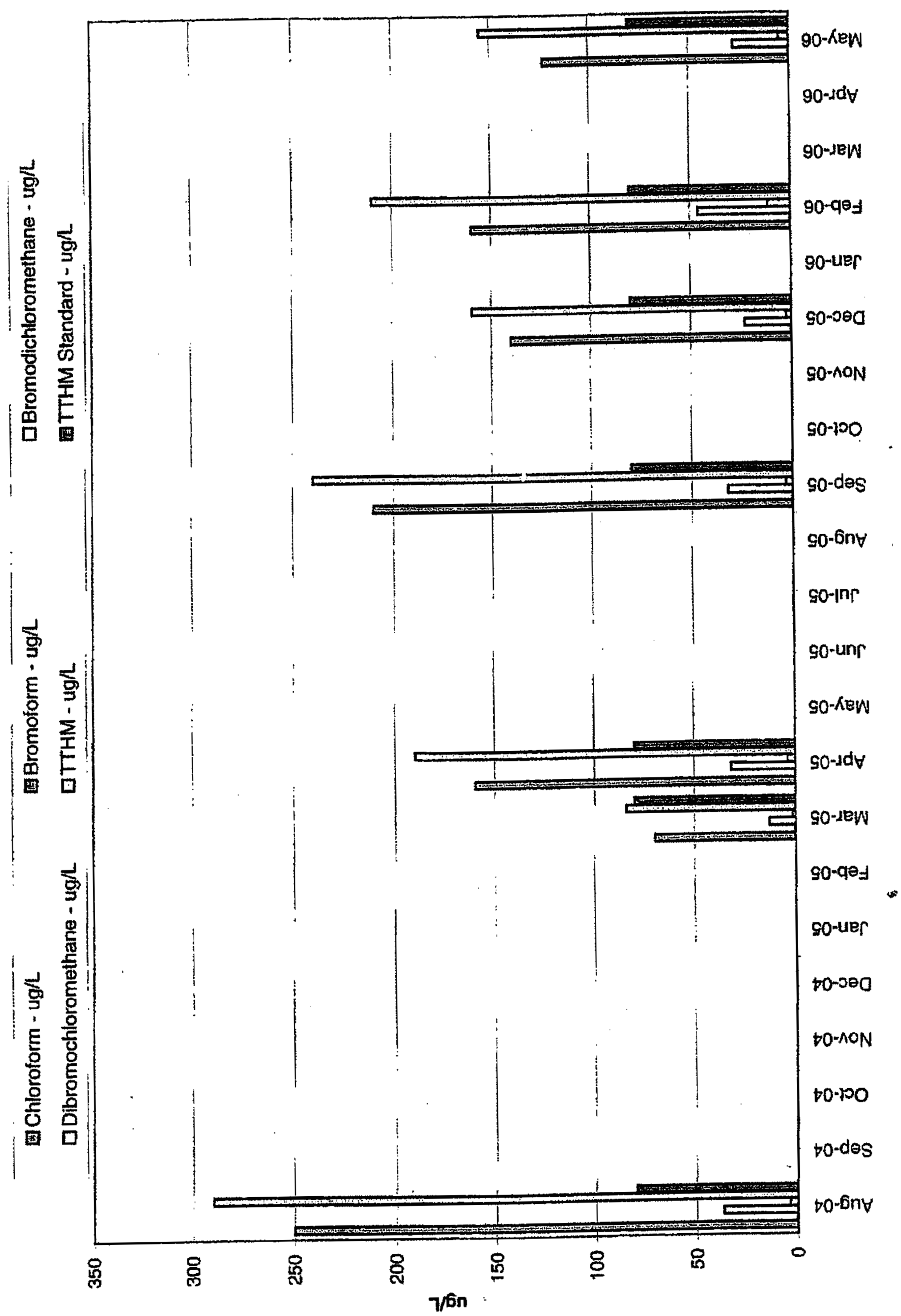
Figure 2. Trihalomethanes



Figures.xls Figure 2

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Figure 3. Haloacetic Acids

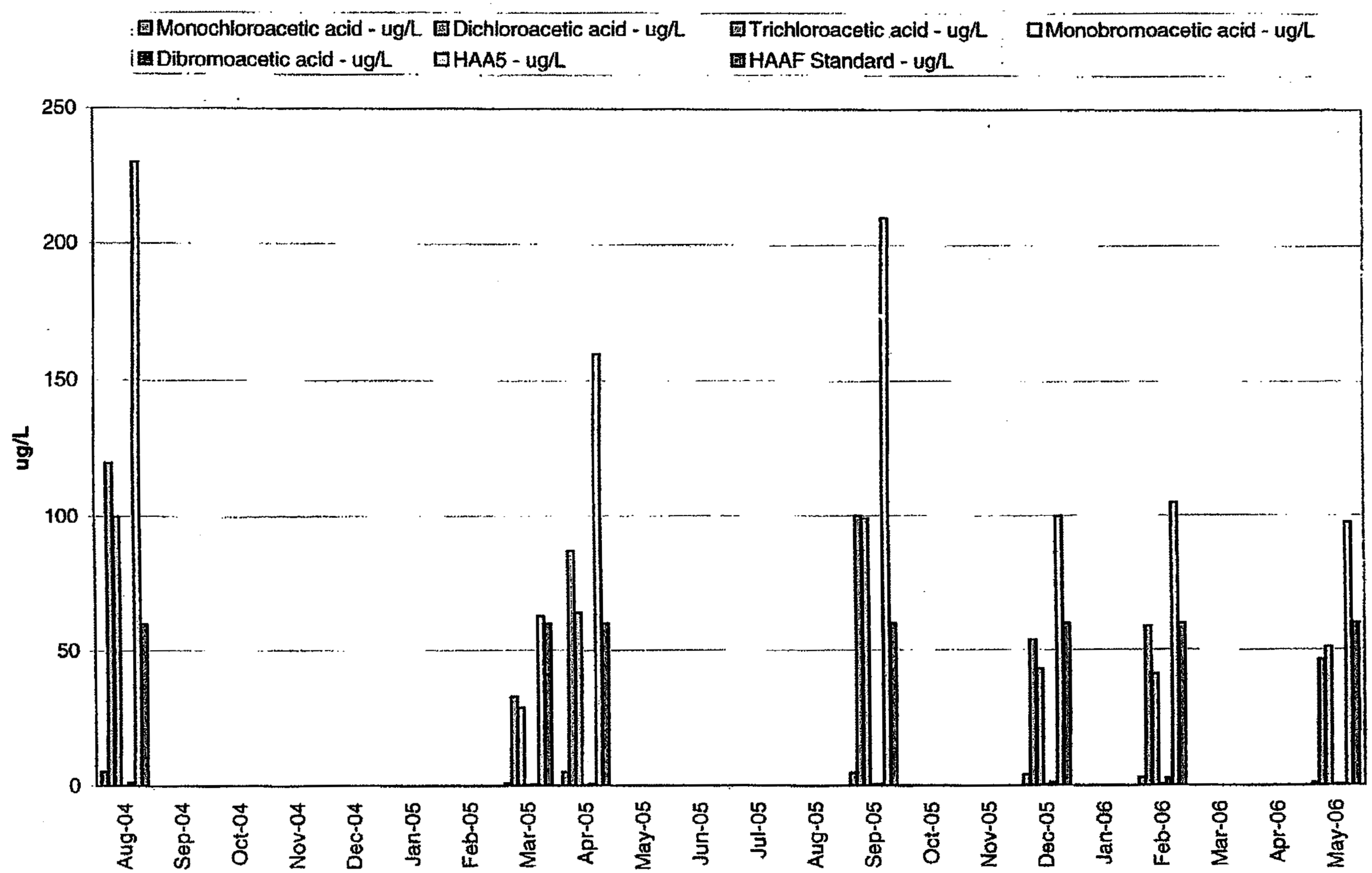

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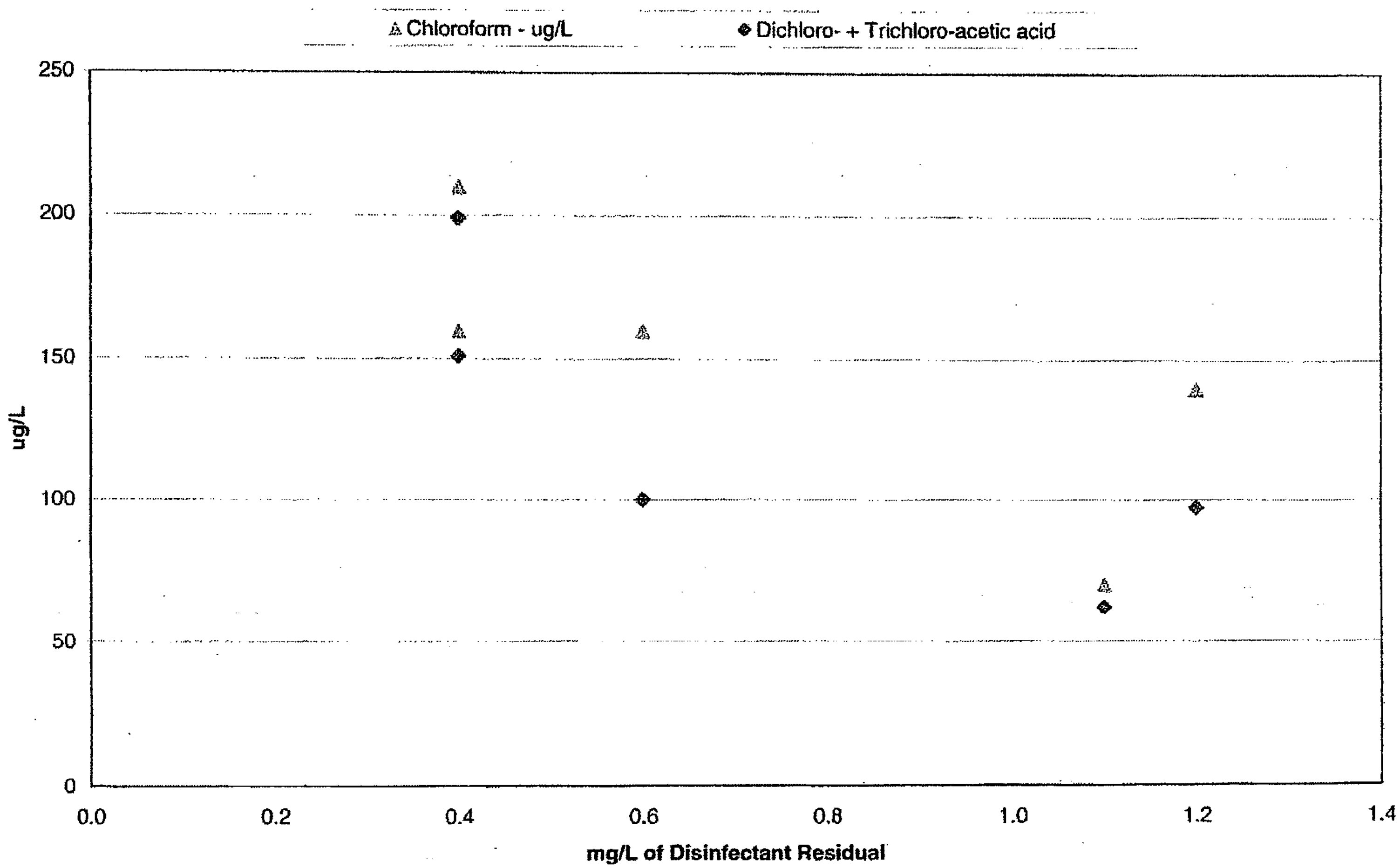
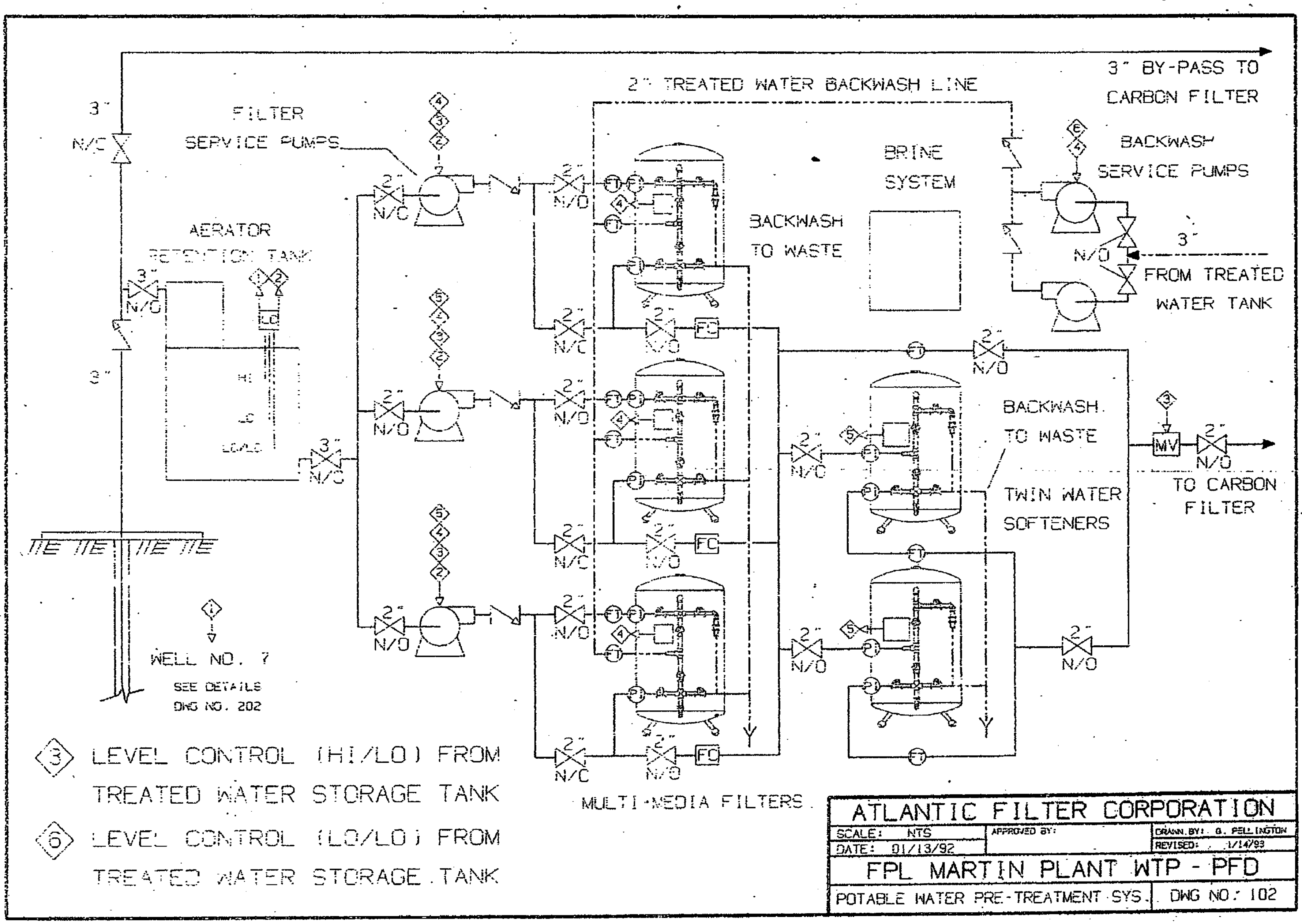
Figure 4. Effect of Disinfectant Residual

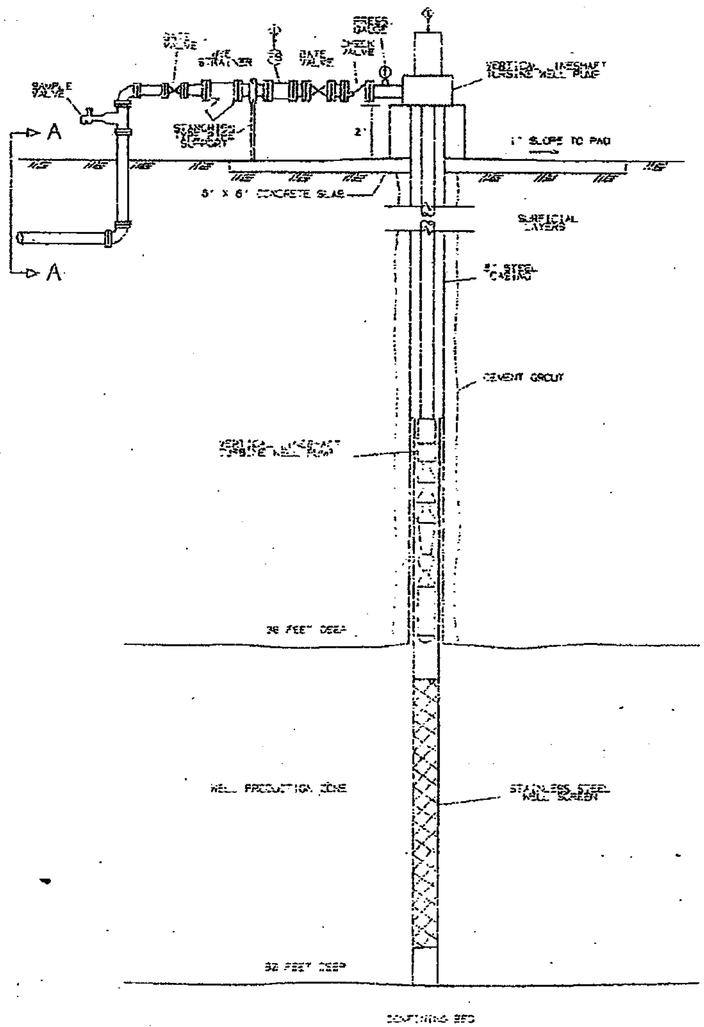


APPENDICES

APPENDIX A. SYSTEM OPERATIONAL MANUAL DRAWINGS

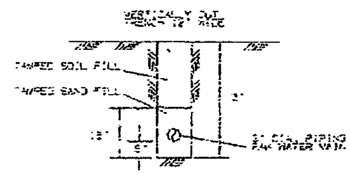

3" BY-PASS TO CARBON FILTER
2" TREATED WATER BACKWASH LINE
FILTER SERVICE PUMPS
BRINE SYSTEM
BACKWASH SERVICE PUMPS
AERATOR RETENTION TANK
BACKWASH TO WASTE
FROM TREATED WATER TANK
TWIN WATER SOFTENERS
TO CARBON FILTER
WELL NO. 7
SEE DETAILS DWG NO. 202
MULTI-MEDIA FILTERS
3 LEVEL CONTROL (HI/LO) FROM TREATED WATER STORAGE TANK
6 LEVEL CONTROL (LO/LO) FROM TREATED WATER STORAGE TANK
ATLANTIC FILTER CORPORATION
SCALE: NTS
DATE: 01/13/92
APPROVED BY:
DRAWN BY: G. PELLINGTON
REVISED: 1/14/93
FPL MARTIN PLANT WTP - PFD
POTABLE WATER PRE-TREATMENT SYS.
DWG NO: 102

WELL NO. 7 DETAIL



WELL DRILLER'S LOG

0-10 FT	TOP SOIL AND SAND
10-30 FT	FINE SHELL
30-35 FT	SAND ROCK WITH SHELL
35-55 FT	SHELL WITH SOME SHELL ROCK
55-60 FT	COARSE SHELL
60-65 FT	SHELL WITH A LITTLE GREEN MARL
65-80 FT	FINE SHELL
80-90 FT	VERY FINE SHELL
90-120 FT	VERY FINE SHELL WITH GREEN AND GRAY SANDY MARL AND LIMESTONE TOP HAWTHORNE AT 153 FT



SECTION A-A

RAW WATER MAIN TRENCH DETAIL

ATLANTIC FILTER CORPORATION

SCALE: NTS	APPROVED BY:	DRAWN BY: G. PELLINGTON
DATE: 01/13/92		REVISED: 9/27/92

FPL MARTIN PLANT WTP-WELL NO. 7

WELL NO. 7 DETAILS	DWG NO. 202

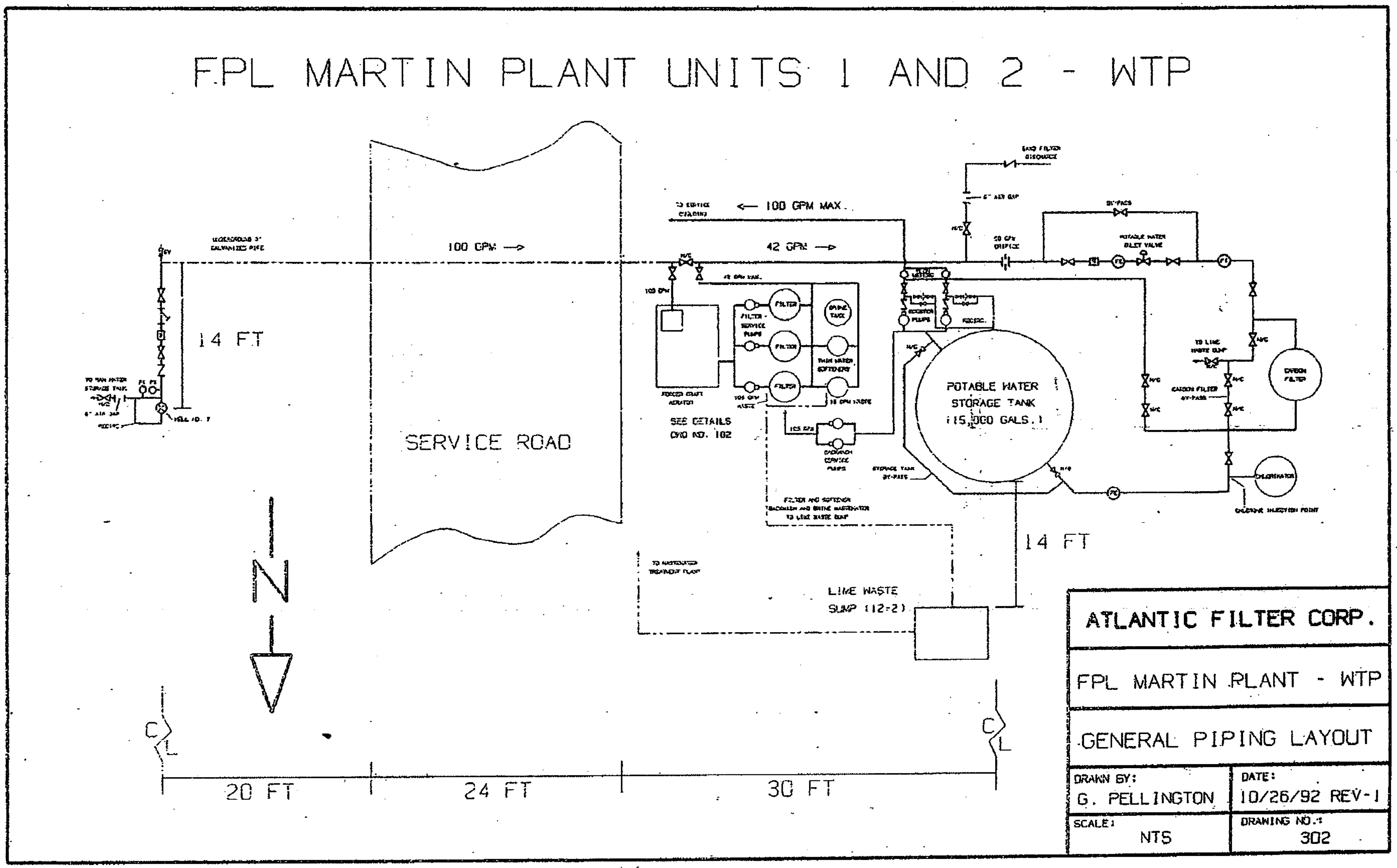


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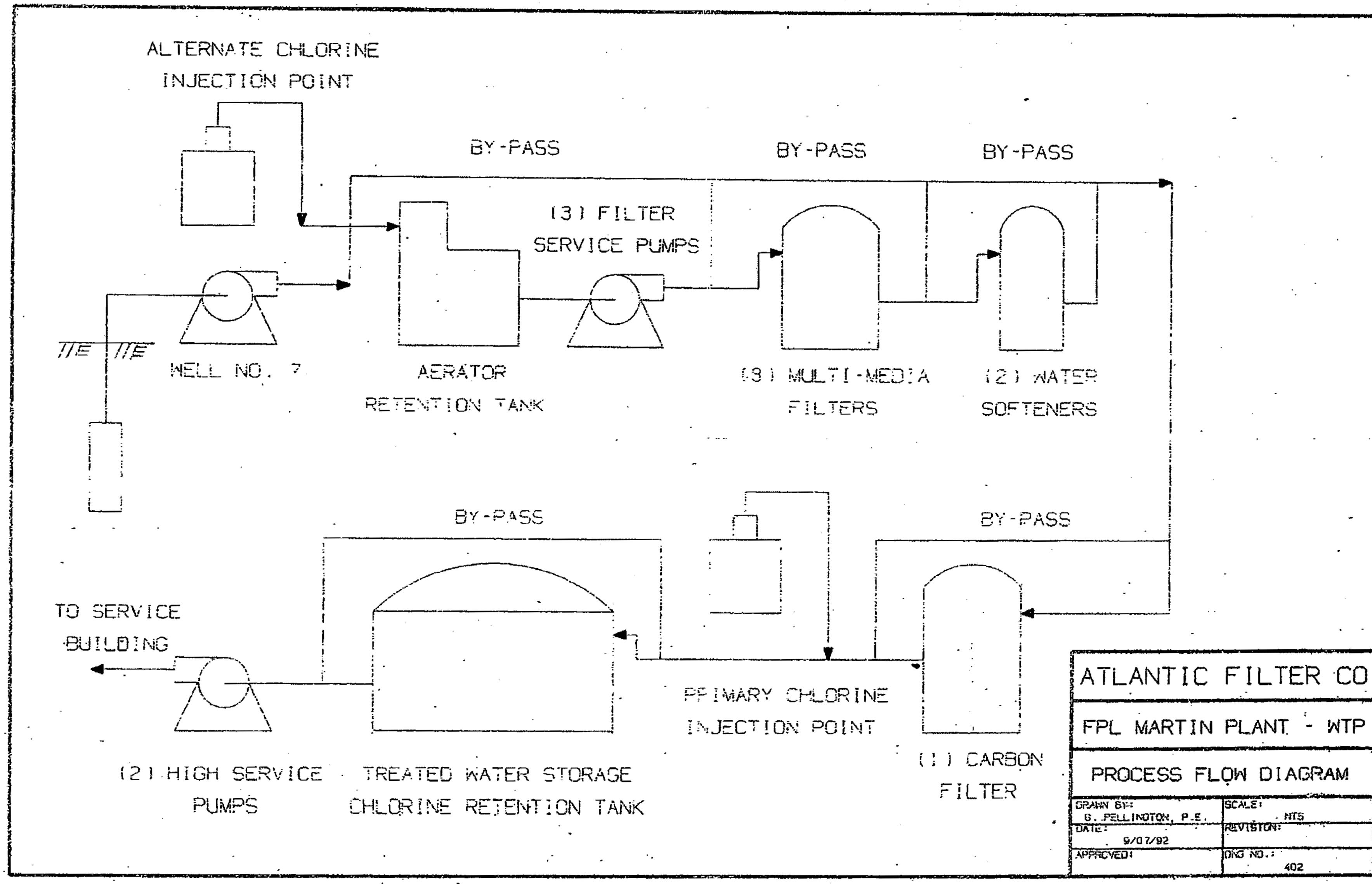
EXHIBIT RRL-3, PAGE 19 OF 107



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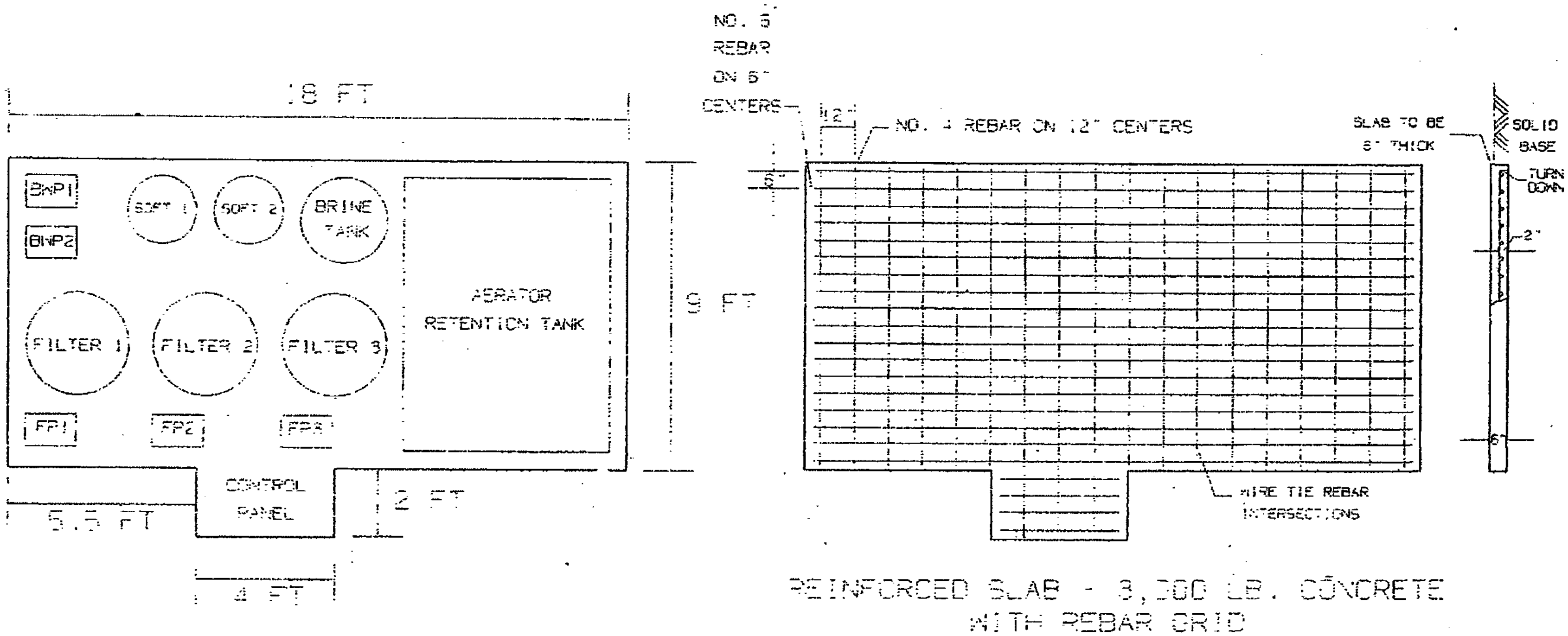
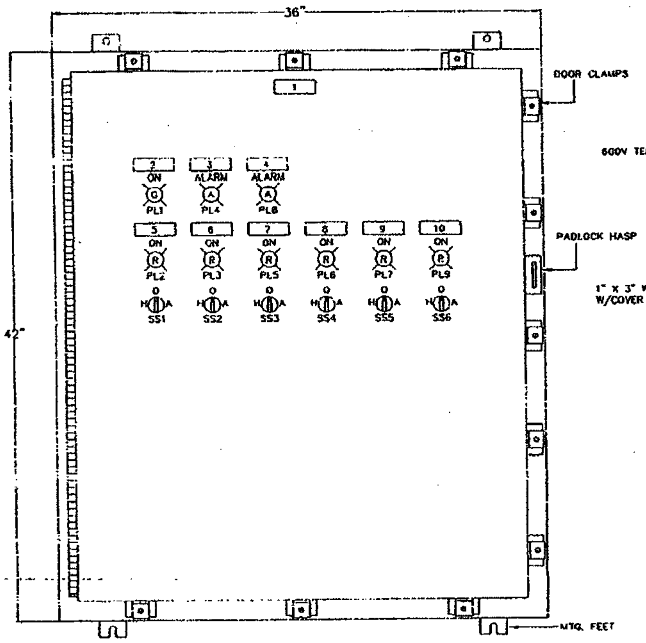
GOLDER ASSOCIATES, INC.
EXHIBIT RRL-3, PAGE 20 OF 107

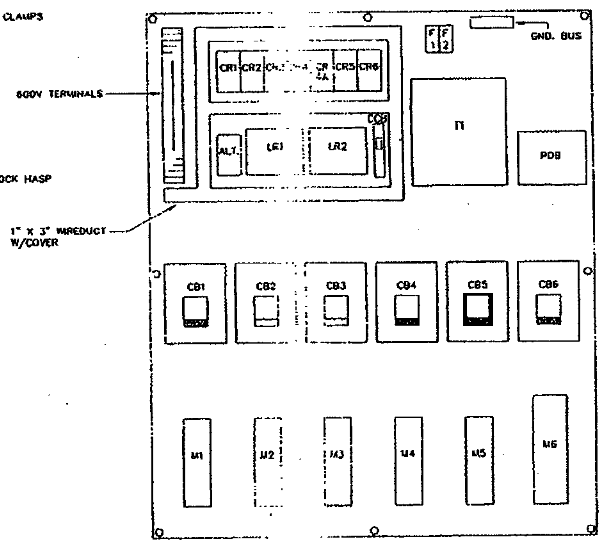


FPL MARTIN PLANT - WTP SLAB DETAIL

ATLANTIC FILTER CORPORATION		
SCALE: NTS	APPROVED BY:	DRAWN BY: GSP
DATE: 10/19/92		REVISED: 01/14/93
FPL MARTIN PLANT WTP - SLAB DETAIL		
POTABLE WATER PRE-TREATMENT SYSTEM		DRAWING NO. 403



FRONT VIEW



SUBPLATE LAYOUT

NAMEPLATE SCHEDULE

1	1" X 3"	PUMP CONTROL PANEL
2	1" X 3"	CONTROL POWER
3	1" X 3"	BACKWASH PUMPS / LOW PRESSURE
4	1" X 3"	RETENTION TANK / LOW LEVEL
5	1" X 3"	BACKWASH SERVICE / PUMP NO.1
6	1" X 3"	BACKWASH SERVICE / PUMP NO.2
7	1" X 3"	FILTER SERVICE / PUMP NO.1
8	1" X 3"	FILTER SERVICE / PUMP NO.2
9	1" X 3"	FILTER SERVICE / PUMP NO.3
10	1" X 3"	WELL NO.7

ITEM	QTY	DESCRIPTION
REMOTE	3	WARRICK 3R6A4 6FT. PVC COATED BRASS PROBES
REMOTE	1	WARRICK 3R6A0 6FT. BRASS PROBE
REMOTE	1	WARRICK 3E4A CAST IRON PROBE HOLDER
REMOTE	2	WARRICK 1E1DO INDUCTION RELAYS 120/300V
	1	GLASTIC 2165-1B INSULATOR
	9	ILSCO SLU-35 GROUND LUGS
	4	SQD CLASS 9080 GH-10 END CLAMPS
	1	SQD CLASS 9080 GR-6B END BARRIER
	25	SQD CLASS 9080 GR-6 600V TERMINALS
	1	SQD CLASS 9080 GF-6B END BARRIER
F1,2	2	SQD CLASS 9080 GF-6 FUSE BLOCKS W/ FNQ-6 FUSES
PL1	1	CUTLER HAMMER E34TB120H3X NEMA 4X GREEN PILOT LIGHT
PL4,8	2	CUTLER HAMMER E34TB120H9X NEMA 4X AMBER PILOT LIGHTS
PL2,3,5-7,9	6	CUTLER HAMMER E34TB120H2X NEMA 4X RED PILOT LIGHTS
SS1-6	6	CUTLER HAMMER E34VHBK1-Y1 NEMA 4X 3POS. SEL. SWITCH
M3	1	CUTLER HAMMER C320KGS1 STARTER AUXILIARY CONTACT
CCB	1	SQD QOU-120 120V 1P 20A CIRCUIT BREAKER
	7	IDEC SR3B05 SOCKETS
CR1-6	7	IDEC RR3B-ULC 3PDT RELAYS (120V)
	1	OMRON PF083A 8 PIN SOCKET
ALT.	1	DIVERSIFIED ELECTRONICS ARA-120-ABA ALTERNATOR
T1	1	ACME TA-2-81219 2KVA 480/120V TRANSFORMER
PDB	1	GOULD 67083 POWER DISTRIBUTION BLOCK
M6	1	CUTLER HAMMER H2012-3 HEATER PACK
M6	1	CUTLER HAMMER A16NDNOA SIZE 1 STARTER
M3-5	3	CUTLER HAMMER H2007-3 HEATER PACKS
M1,2	2	CUTLER HAMMER H2009-3 HEATER PACKS
M1-5	5	CUTLER HAMMER AN16BNOA SIZE 0 STARTER (120V)
CB6	1	CUTLER HAMMER FS340040A 480V 3P 40A CIRCUIT BREAKER
CB1-5	5	CUTLER HAMMER FS340015A 480V 3P 15A CIRCUIT BREAKERS
	1	ELECTROMATE E42P36 SUBPANEL
ENCL.	1	ELECTROMATE E42H36B NEMA 4X ENCLOSURE

BILL OF MATERIAL

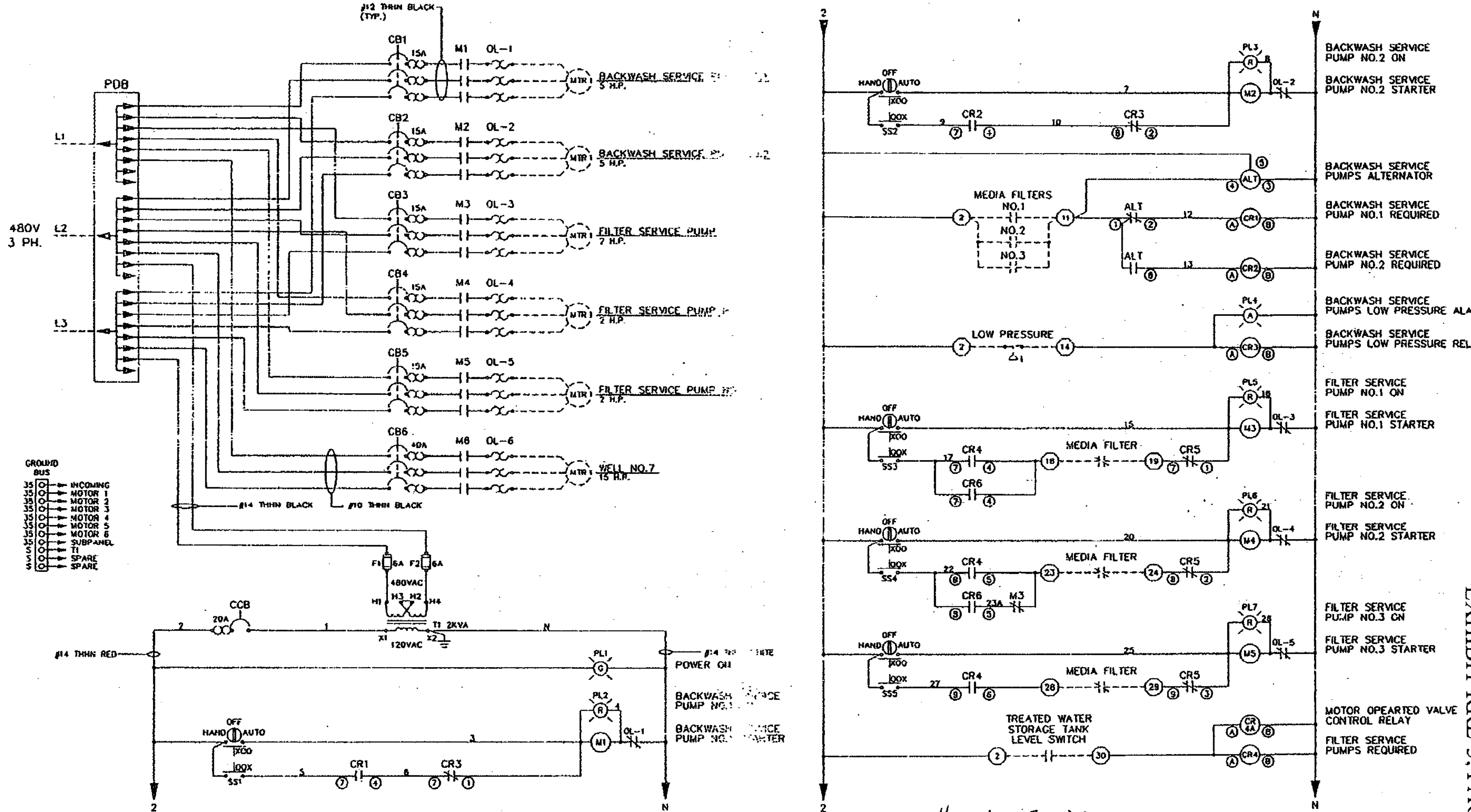
PUMP CONTROL PANEL
1-REQ'D

ATLANTIC FILTER

SYM.	CHANGE	BY	DATE

CAD REF.: A;J652PF-1

DRAWN BY/DATE: LG 12-18-91
CHECKED BY/DATE: CH 12-18-91
PROJECT: FP&L WATER TREATMENT SYSTEM MARTIN PLANT, UNITS 1 &
CUSTOMER: FLORIDA POWER AND LIGHT
SHEET: 1 OF 3
JOB NO. J652



4 ⊣⊢ 7 ⊣/⊢ 1
5 ⊣⊢ 8 ⊣/⊢ 2
6 ⊣⊢ 9 ⊣/⊢ 3
control relays

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NOTE:

ALL CONTROL WIRING WITHIN CONTROL CABINET TO BE #14 TFFN CU. UNLESS OTHERWISE NOTED

○ DESIGNATES TERMINALS FOR CUSTOMER CONNECTION

WIRE ENDS WITHIN CABINET TO BE IDENTIFIED WITH WIRE MARKERS.

ALL WIRES EXTERNAL TO CONTROL CABINET TO BE TERMINATED TO A TERMINAL

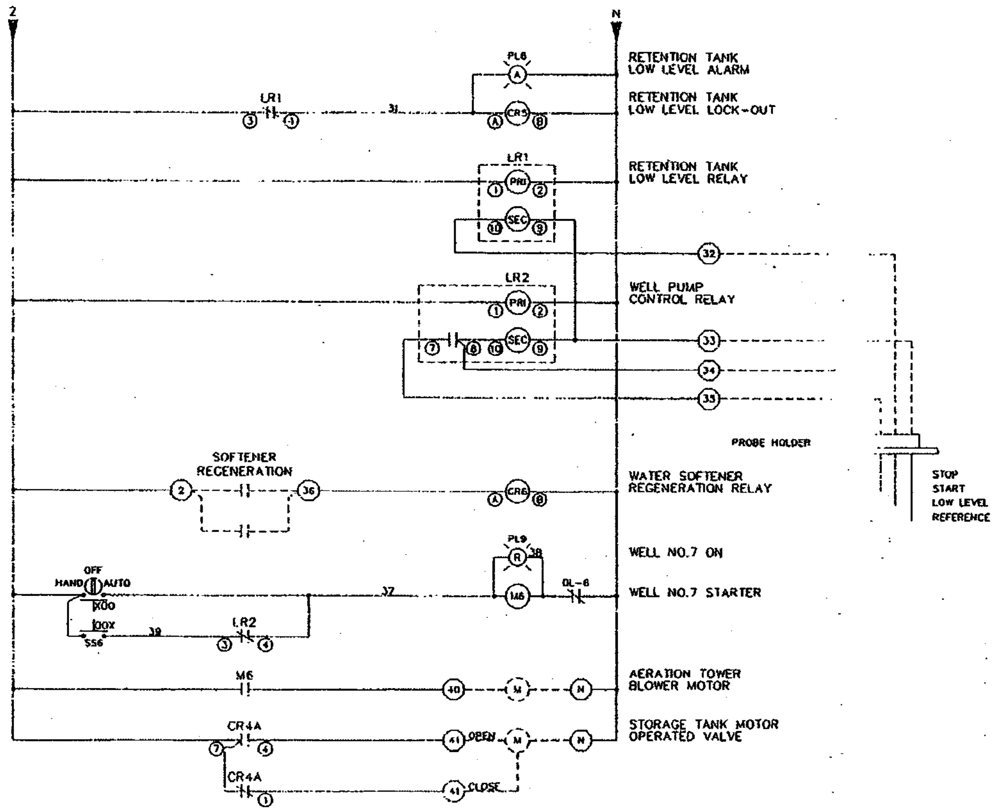
PUMP CONTROL PANEL

SYM.	CHANGE	BY	DATE

CAD REF.: A: J652S-2

ATLANTIC FILTER

DRAWN BY/DATE:	PROJECT:		
LG 12-18-91	FP&L WATER TREATMENT SYSTEM MARTIN PLANT, UNITS 1 &		
CHECKED BY/DATE:	CUSTOMER:	SHEET	JOB NO.
CH 12-18-91	FLORIDA POWER AND LIGHT	2 of 3	J652

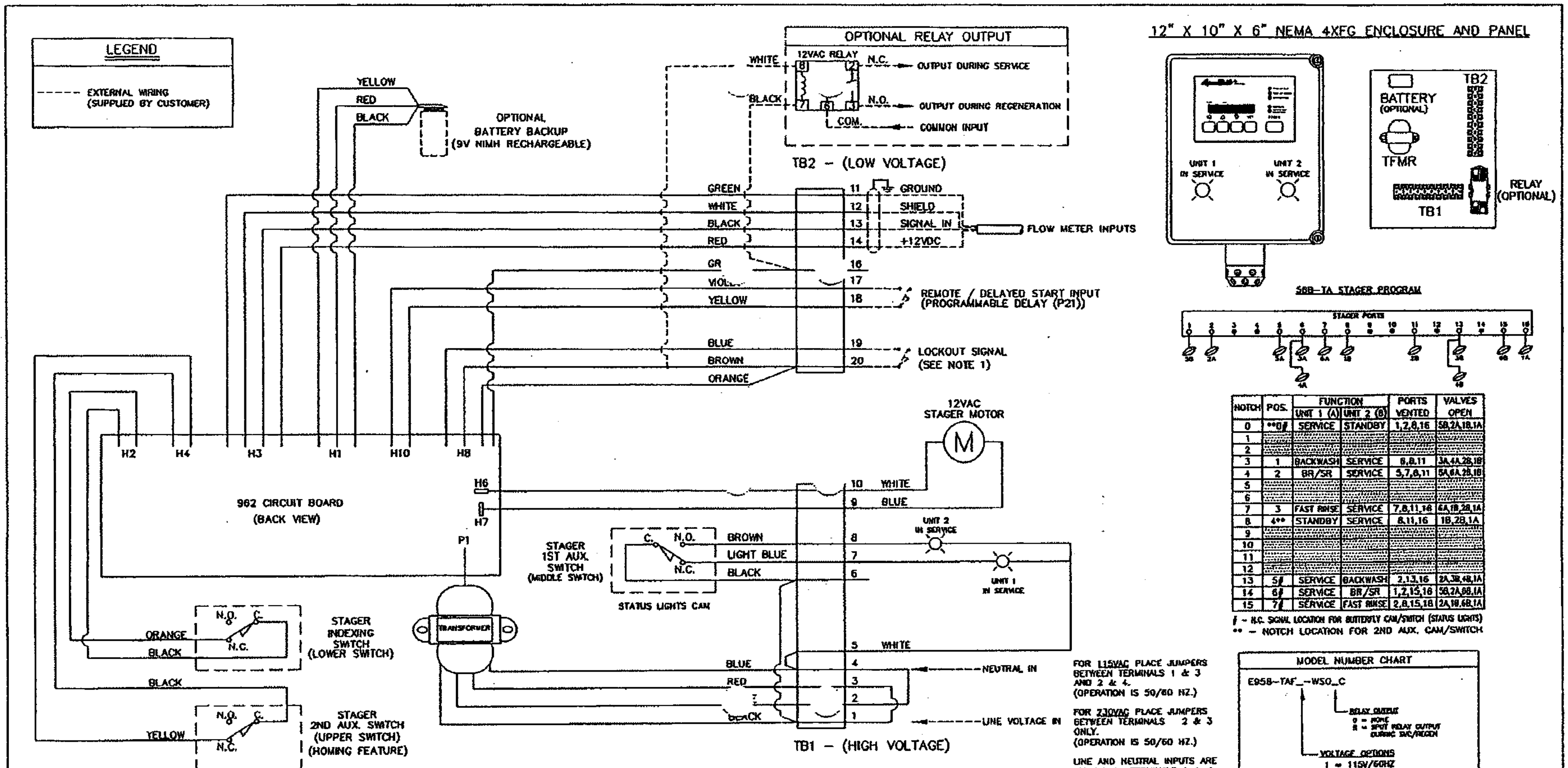


PUMP CON[illegible] PANEL

SYM.	CHANGE	BY	DATE
CAD REF.: A:J652S-3			

ATLANTIC FILTER

DRAWN BY/DATE: LG 12-18-91	PROJECT: FP&L WATER TREATMENT SYSTEM MARTIN PLANT, UNITS 1 & 2		
CHECKED BY/DATE: CH 12-18-91	CUSTOMER: FLORIDA POWER AND LIGHT	SHEET 3 of 3	JOB NO. J652



NOTCH	POS.	FUNCTION UNIT 1 (A)	FUNCTION UNIT 2 (B)	PORTS VENTED	VALVES OPEN
0	**0ǂ	SERVICE	STANDBY	1,2,8,16	5B,2A,1B,1A
1					
2					
3	1	BACKWASH	SERVICE	6,8,11	3A,4A,2B,1B
4	2	BR/SR	SERVICE	5,7,8,11	5A,6A,2B,1B
5					
6					
7	3	FAST RINSE	SERVICE	7,8,11,16	6A,1B,2B,1A
8	4**	STANDBY	SERVICE	8,11,16	1B,2B,1A
9					
10					
11					
12					
13	5ǂ	SERVICE	BACKWASH	2,13,16	2A,3B,4B,1A
14	6ǂ	SERVICE	BR/SR	1,2,15,16	5B,2A,6B,1A
15	7ǂ	SERVICE	FAST RINSE	2,8,15,16	2A,1B,6B,1A

ǂ – N.C. SIGNAL LOCATION FOR BUTTERFLY CAM/SWITCH (STATUS LIGHTS)
** – NOTCH LOCATION FOR 2ND AUX. CAM/SWITCH

NOTES: 1 LOCKOUT FUNCTION IS VOID WHEN USING OPTIONAL RELAY OUTPUT.

REV	DESCRIPTION	ECO	DWN	DATE	APVD
F	UPDATED STAGER REV	1259	MSM	04JUN01	
E	ADDED RELAY OPTION	1341	MSM	12SEP00	QLC 12SEP00
D	CHG WIRING FOR SW V1.2	1337	QLC	02AUG00	MSM 12SEP00
C	UPDATED MODEL No. CHART	NONE	RS	08 MAR00	QLC 09MAR00
B	1. CHANGED WIRE COLORS ON TERMINALS 5,7,8,17,18,19,20 2. CHANGED H4 TO BE WIRED THROUGH INDEXING SWITCH.	NONE	QLC	18FEB00	QLC 18 FEB00
A	INITIAL RELEASE	NONE	QLC	17JAN00	MSM 17JAN00

OSMONICS
ROCKFORD OPERATIONS
2412 GRANT AVENUE, ROCKFORD, IL 61103-3091 (815) 964-9421
WWW.OSMONICS.COM

SCALE NONE	THIRD ANGLE	DWN BY QLC	DATE 17 JAN 00	962 CONTROLLER W/ 58B-TA STAGER PRODUCT DRAWING	
		CHKD BY VKP	DATE 01FEB00		
DO NOT SCALE		APVD BY MSM	DATE 01FEB00	PART NO. SEE MODEL NO. CHART	DWG. NO. 1070609
		APVD BY	DATE		

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GOLDER ASSOCIATES, INC.
EXHIBIT RRL-3, PAGE 25 OF 107

APPENDIX B. CONSENT ORDER

DOCKET NO. 070007-EI
GOLDER ASSOCIATES, INC.
EXHIBIT RRL-3, PAGE 27 OF 107

Department of Environmental Protection

Jeb Bush
Governor

Southeast District
400 N. Congress Avenue, Suite 200
West Palm Beach, Florida 33401

Colleen M. Castille
Secretary

AUG 04 2006

CERTIFIED MAIL #7005 2570 0001 9601 9727
RETURN RECEIPT REQUESTED

Craig Arcari, General Manager
Florida Power & Light Company – Martin Plant
P.O. Box 176
Indiantown, Florida 34954

Re: DEP vs. Florida Power & Light Company
OGC File No. 06-0744/FPL Martin Plant PWS #4431748

Dear Mr. Arcari:

Enclosed for your review and signature is the Consent Order drafted by the Department in the above-styled case. The Consent Order represents the resolution acceptable to the Department in this matter. Please review, sign, and return the Consent Order to this office within 30 days of receipt for Department signature and distribution.

Thank you for your cooperation in this matter. If you have any questions concerning the Consent Order, please contact Michele Owens of this office at 561/681-6700.

Sincerely,

Kevin R. Neal 8/3/06

Kevin R. Neal — Date
District Director
Southeast District

KRN/LAH/TRB/mo

Enclosure (all)

cc: Drinking Water Compliance Section – DEP/PSL

BEFORE THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION, Complainant, vs. FLORIDA POWER & LIGHT COMPANY, Respondent.	IN THE OFFICE OF THE SOUTHEAST DISTRICT OGC FILE NO. 06-0744

CONSENT ORDER

This Consent Order is entered into between the State of Florida Department of Environmental Protection ("Department") and Florida Power & Light Company ("Respondent") to reach settlement of certain matters at issue between the Department and Respondent.

The Department finds and the Respondent neither admits nor denies the following:

1. The Department is the administrative agency of the State of Florida having the power and duty to protect Florida's air and water resources and to administer and enforce the provisions of the Florida Safe Drinking Water Act, Sections 403.850 et seq., Florida Statutes, and the rules promulgated thereunder, Title 62, Florida Administrative Code. The Department has jurisdiction over the matters addressed in this Consent Order.

2. Respondent is a "person" within the meaning of Section 403.852(5), Florida Statutes.

3. Respondent is the owner and is responsible for the operation of a nontransient noncommunity public water system ("System"), PWS #4431748, located on Warfield Boulevard, northwest of Indiantown, Martin County, Florida, which serves the Florida Power & Light Martin Power Plant.

4. The Department finds that Respondent is in violation of Rule 62-550.310(3), Fla. Admin. Code which establishes the maximum contaminant levels (MCLs) for total

trihalomethanes (TTHMs) and haloacetic acids (five) (HAA5s) as 0.080 milligrams per liter (mg/L) and 0.060 mg/L, respectively. The average results for samples collected from the System on March 15, 2005, April 12, 2005, September 14, 2005, and December 28, 2005, and analyzed for total trihalomethanes (TTHMs) and haloacetic acids (five) (HAA5s) are 0.173 milligrams per liter (mg/L) and 0.132 mg/L, respectively.

Having reached a resolution of the matter the Department and the Respondent mutually agree and it is

ORDERED:

5. Respondent shall comply with the following corrective actions within the stated time periods:

a. By September 1, 2006, Respondent shall retain the services of a Florida-registered professional engineer to evaluate the System and either submit an application, along with any required application fees, to the Department for a permit to construct any modifications needed to address the MCL exceedances, or, if the evaluation determines that no additional treatment is needed, a plan of corrective action ("Plan") with interim milestone dates, signed and sealed by a Florida-registered Professional Engineer.

b. The Department shall review the application/Plan submitted pursuant to paragraph 5.a. above. In the event additional information, modifications or specifications are necessary to process the application/Plan, the Department shall issue a written request for information ("RFI") to Respondent for such information. Respondent shall accordingly submit the requested information in writing to the Department within 30 days of receipt of the request. Respondent shall provide all information requested in any additional RFIs issued by the Department within 30 days of receipt of each request. Within 60 days of the date the Department receives the application/Plan pursuant to paragraph 5.a. above, Respondent shall provide all information necessary to complete the application/Plan. The Department shall notify Respondent in writing of Department approval of the Plan.

c. Within 180 days of issuance of any required permit(s), or written Department approval, if no permit is required, Respondent shall complete the Department-approved modifications in accordance with the permit/written approval issued pursuant to paragraphs 5.a. and 5.b. above, and submit to the Department the engineer's certification of completion of construction, along with all required supporting documentation. Respondent shall receive written Department clearance prior to placing the System modifications into service.

d. Respondent shall continue to sample quarterly for TTHMs and HAA5s. Results shall be submitted to the Department within ten (10) days of Respondent's receipt of the results.

e. In the event that the modifications approved by the Department pursuant to paragraphs 5.a. and b. are determined to be inadequate to resolve the MCL exceedances, the Department will notify the Respondent in writing. Within 30 days of receipt of written notification from the Department that the results of the quarterly sampling indicate that the System modifications have not resolved the violations, Respondent shall submit another proposal to address the MCL exceedances. Respondent shall provide all information requested in any RFIs issued by the Department within 30 days of receipt of each request. Within 60 days of the date the Department receives the application pursuant to this paragraph, Respondent shall provide all information necessary to complete the application.

f. Within two years of the effective date of this Consent Order, Respondent shall complete all corrective actions needed to resolve the MCL exceedances and submit written certification of completion to the Department for all modifications.

g. Respondent shall continue to issue public notice regarding the MCL exceedances every 90 days in accordance with Rule 62-560.410(1), Fla. Admin. Code, until the Department determines that System is in compliance with all MCLs. Respondent shall submit certification of delivery of public notice, using DEP Form 62-555.900(22), to the Department within ten days of issuing each public notice.

6. Within 30 days of the effective date of this Consent Order, Respondent shall reimburse the Department for costs and expenses in the amount of $500.00 which were incurred by the Department during the investigation of this matter and the preparation and tracking of this Consent Order. Payment shall be made by cashier's check or money order. The instrument shall be made payable to the "Department of Environmental Protection" and shall include thereon the OGC number assigned to this Consent Order and the notation "Ecosystem Management and Restoration Trust Fund."

7. Respondent agrees to pay the Department stipulated penalties in the amount of $100.00 per day for each and every day Respondent fails to timely comply with any of the requirements of paragraphs 5 and 6 of this Consent Order. A separate stipulated penalty shall be assessed for each violation of this Consent Order. Within 30 days of written demand from the Department, Respondent shall make payment of the appropriate stipulated penalties to "The Department of Environmental Protection" by cashier's check or money order and shall include the OGC number assigned to this Consent Order and the notation "Ecosystem Management and Restoration Trust Fund". Payment shall be sent to the Department of Environmental Protection, 400 North Congress Avenue, Suite 200, West Palm Beach, FL 33401. The Department may make demands for payment at any time after violations occur. Nothing in this paragraph shall prevent the Department from filing suit to specifically enforce any of the terms of this Consent Order. Any penalties assessed under this paragraph shall be in addition to the $500.00 agreed to in paragraph 6 of this Consent Order.

8. If any event, including administrative or judicial challenges by third parties unrelated to the Respondent, occurs which causes delay or the reasonable likelihood of delay, in complying with the requirements of this Consent Order, Respondent shall have the burden of proving the delay was or will be caused by circumstances beyond the reasonable control of the Respondent and could not have been or cannot be overcome by Respondent's due diligence. Economic circumstances shall not be considered circumstances beyond the control of Respondent, nor shall the failure of a contractor, subcontractor, materialman or other agent

(collectively referred to as "contractor") to whom responsibility for performance is delegated to meet contractually imposed deadlines be a cause beyond the control of Respondent, unless the cause of the contractor's late performance was also beyond the contractor's control. Upon occurrence of an event causing delay, or upon becoming aware of a potential for delay, Respondent shall notify the Department's Southeast District Office in West Palm Beach orally within 72 hours or within three working days and shall, within ten calendar days of oral notification to the Department, notify the Department in writing of the anticipated length and cause of the delay, the measures taken or to be taken to prevent or minimize the delay and the timetable by which Respondent intends to implement these measures. If the parties can agree that the delay or anticipated delay has been or will be caused by circumstances beyond the reasonable control of Respondent, the time for performance of one or more of the requirements hereunder shall be extended for a period equal to the agreed delay resulting from such circumstances. Such agreement shall adopt all reasonable measures necessary to avoid or minimize delay. Failure of Respondent to comply with the notice requirements of this Paragraph in a timely manner shall constitute a waiver of Respondent's right to request an extension of time for compliance with the requirements of this Consent Order.

9. Persons who are not parties to this Consent Order, but whose substantial interests are affected by this Consent Order, have a right, pursuant to Sections 120.569 and 120.57, Florida Statutes, to petition for an administrative hearing on it. The Petition must contain the information set forth below and must be filed (received) at the Department's Office of General Counsel, 3900 Commonwealth Boulevard, MS# 35, Tallahassee, Florida 32399-3000 within 21 days of receipt of this notice. A copy of the Petition must also be mailed at the time of filing to the District Office named above at the address indicated. Failure to file a petition within the 21 days constitutes a waiver of any right such person has to an administrative hearing pursuant to Sections 120.569 and 120.57, Florida Statutes.

10. The petition shall contain the following information:

a. The name, address, and telephone number of each petitioner; the Department's Consent Order identification number and the county in which the subject matter or activity is located;

b. A statement of how and when each petitioner received notice of the Consent Order;

c. A statement of how each petitioner's substantial interests are affected by the Consent Order;

d. A statement of the material facts disputed by petitioner, if any;

e. A statement of facts which petitioner contends warrant reversal or modification of the Consent Order;

f. A statement of which rules or statutes petitioner contends require reversal or modification of the Consent Order;

g. A statement of the relief sought by petitioner, stating precisely the action petitioner wants the Department to take with respect to the Consent Order.

11. If a petition is filed, the administrative hearing process is designed to formulate agency action. Accordingly, the Department's final action may be different from the position taken by it in this Notice. Persons whose substantial interests will be affected by any decision of the Department with regard to the subject Consent Order have the right to petition to become a party to the proceeding. The petition must conform to the requirements specified above and be filed (received) within 21 days of receipt of this notice in the Office of General Counsel at the above address of the Department. Failure to petition within the allowed time frame constitutes a waiver of any right such person has to request a hearing under Sections 120.569 and 120.57, Florida Statutes, and to participate as a party to this proceeding. Any subsequent intervention will only be at the approval of the presiding officer upon motion filed pursuant to Rule 28-106.205, Florida Administrative Code.

12. A person whose substantial interests are affected by the Consent Order may file a timely petition for an administrative hearing under Sections 120.569 and 120.57, Florida

Statutes, or may choose to pursue mediation as an alternative remedy under Section 120.573, Florida Statutes, before the deadline for filing a petition. Choosing mediation will not adversely affect the right to a hearing if mediation does not result in a settlement. The procedures for pursuing mediation are set forth below.

13. Mediation may only take place if the Department and all the parties to the proceeding agree that mediation is appropriate. A person may pursue mediation by reaching a mediation agreement with all parties to the proceeding (which include the Respondent, the Department, and any person who has filed a timely and sufficient petition for a hearing) and by showing how the substantial interests of each mediating party are affected by the Consent Order. The agreement must be filed in (received by) the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, MS #35, Tallahassee, Florida 32399-3000, within 10 days after the deadline as set forth above for the filing of a petition.

14. The agreement to mediate must include the following:

a. The names, addresses, and telephone numbers of any persons who may attend the mediation;

b. The name, address, and telephone number of the mediator selected by the parties, or a provision for selecting a mediator within a specified time;

c. The agreed allocation of the costs and fees associated with the mediation;

d. The agreement of the parties on the confidentiality of discussions and documents introduced during mediation;

e. The date, time, and place of the first mediation session, or a deadline for holding the first session, if no mediator has yet been chosen;

f. The name of each party's representative who shall have authority to settle or recommend settlement;

g. Either an explanation of how the substantial interests of each mediating party will be affected by the action or proposed action addressed in this notice of intent or a statement clearly identifying the petition for hearing that each party has already filed, and incorporating it by reference; and

h. The signatures of all parties or their authorized representatives. As provided in Section 120.573, Florida Statutes, the timely agreement of all parties to mediate will toll the time limitations imposed by Sections 120.569 and 120.57, Florida Statutes, for requesting and holding an administrative hearing. Unless otherwise agreed by the parties, the mediation must be concluded within sixty days of the execution of the agreement. If mediation results in settlement of the administrative dispute, the Department must enter a final order incorporating the agreement of the parties. Persons whose substantial interests will be affected by such a modified final decision of the Department have a right to petition for a hearing only in accordance with the requirements for such petitions set forth above, and must therefore file their petitions within 21 days of receipt of this notice. If mediation terminates without settlement of the dispute, the Department shall notify all parties in writing that the administrative hearing processes under Sections 120.569 and 120.57, Florida Statutes, remain available for disposition of the dispute, and the notice will specify the deadlines that then will apply for challenging the agency action and electing remedies under those two statutes.

15. Respondent shall allow all authorized representatives of the Department access to the facility at reasonable times for the purpose of determining compliance with the terms of this Consent Order and the rules and statutes of the Department.

16. All submittals and payments required by this Consent Order to be submitted to the Department shall be sent to the Florida Department of Environmental Protection, Southeast District Water Facilities Program, 400 North Congress Avenue, Suite 200, West Palm Beach, Florida, 33401.

17. This Consent Order is a settlement of the Department's civil and administrative authority arising under Florida law to resolve the matters addressed herein. This Consent Order is not a settlement of any criminal liabilities, which may arise under Florida law, nor is it a

settlement of any violation which may be prosecuted criminally or civilly under federal law and which Respondent may defend.

18. The Department hereby expressly reserves the right to initiate appropriate legal action to prevent or prohibit any violations arising after the date of this Consent Order of applicable statutes, or the rules promulgated thereunder that are not specifically addressed by the terms of this Consent Order.

19. The terms and conditions set forth in this Consent Order may be enforced in a court of competent jurisdiction pursuant to Sections 120.69 and 403.121, Florida Statutes. Failure to comply with the terms of this Consent Order shall constitute a violation of Section 403.859, Florida Statutes.

20. The Department, for and in consideration of the complete and timely performance by Respondent of the obligations agreed to in this Consent Order, hereby waives its right to seek judicial imposition of damages or civil penalties for alleged violations.

21. Respondent is fully aware that a violation of the terms of this Consent Order may subject Respondent to judicial imposition of damages, civil penalties up to $5,000.00 per day per violation, and criminal penalties, except as limited by the provisions of this Consent Order.

22. Except as otherwise provided herein, entry of this Consent Order does not relieve Respondent of the need to comply with applicable federal, state or local laws, regulations or ordinances.

23. No modifications of the terms of this Consent Order shall be effective until reduced to writing and executed by both Respondent and the Department.

24. Respondent acknowledges and waives its right to an administrative hearing pursuant to Sections 120.569 and 120.57, Florida Statutes, on the terms of this Consent Order. Respondent acknowledges its right to appeal the terms of this Consent Order pursuant to Section 120.68, Florida Statutes, and waives that right upon signing this Consent Order.

25. This Consent Order is a final order of the Department pursuant to Section 120.52(7), Florida Statutes, and it is final and effective on the date filed with the Clerk of the

Department unless a Petition for Administrative Hearing is filed in accordance with Chapter 120, Florida Statutes. Upon the timely filing of a petition this Consent Order will not be effective until further order of the Department.

FOR THE RESPONDENT:

Craig Arcari, General Manager Date
Florida Power & Light Company - Martin Plant
P.O. Box 176
Indiantown, Florida 34954

DONE AND ORDERED this ___ day of __________, 200_, in West Palm Beach, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Kevin R. Neal Date
District Director
Southeast District

FILED, on this date, pursuant to §120.52 Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Clerk **Date**

Copies furnished to:
Lea Crandall, Agency Clerk, MS 35
Drinking Water Compliance Section, FDEP/PSL

APPENDIX C. CALCULATIONS

Golder Associates

SUBJECT DBP Water Quality Data		
Job No. 063-3495 Ref. Calc 001	Made by NAE Checked SWM Reviewed MD	Date 8/16/06 Sheet 1 of 1

Received Tabulated Data from Willie Welch & Stan McElroy during site visit (attached)

Data were input to spreadsheet data.xls, and results shown on Exhibits 1–4

Conclusion:

The Total Tri-halomethane problem is caused primarily by the presence of chloroform

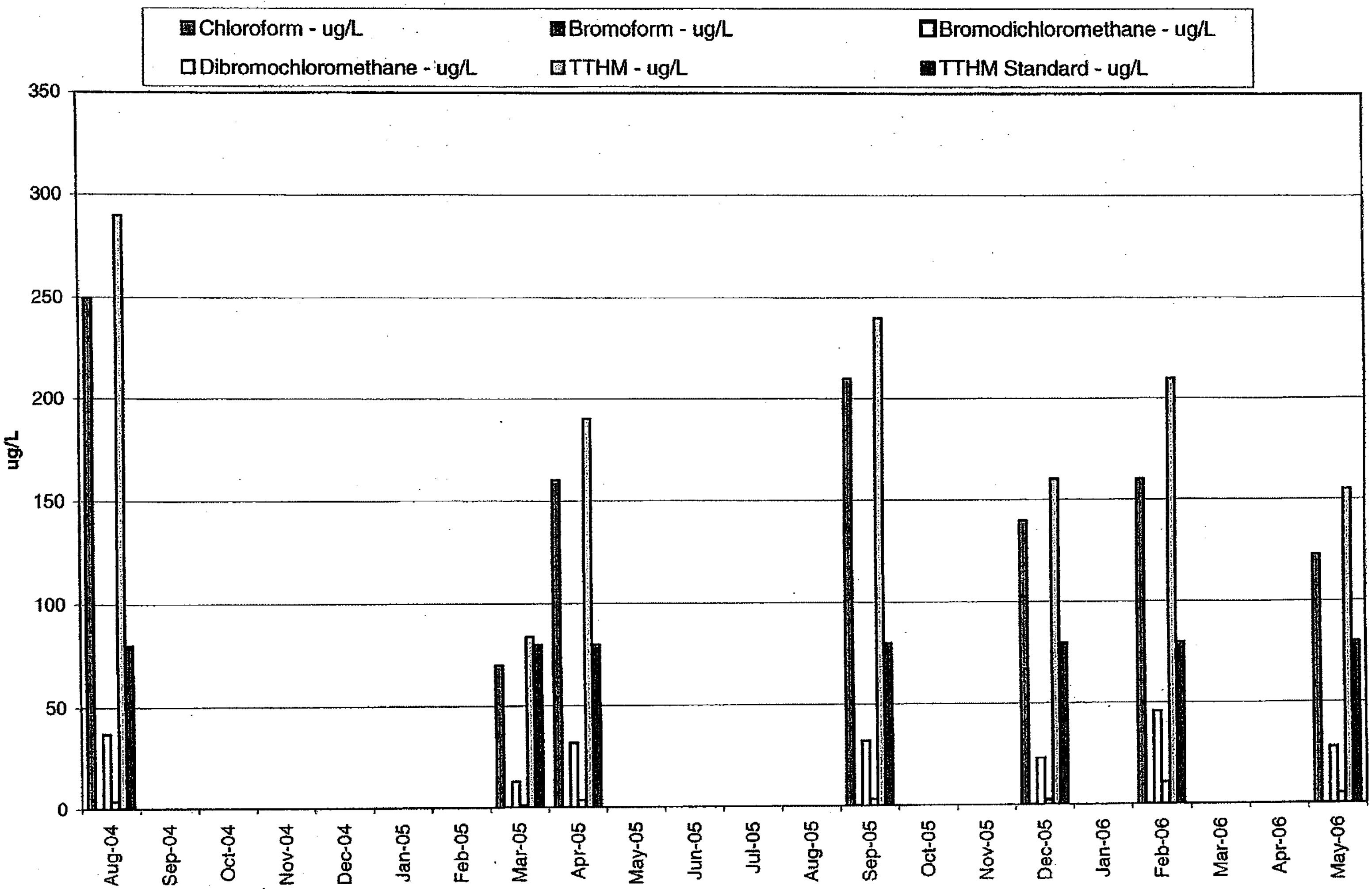
The Total Halo-acetic acid problem is caused by two compounds: Di- and Tri-chloroacetic acid

Location	Potable POE	MRT	MRT	MRT	MRT	MRT	MRT
Date	8/25/2004	5/25/2006	2/13/2006	12/21/2005	9/14/2005	4/12/2005	3/15/2005
Monochloroacetic acid - ug/L	5.3	U	2.8	4 ✓	4.7	4.9	U
Dichloroacetic acid - ug/L	120	46.4	59	54 ✓	100	87	33
Trichloroacetic acid - ug/L	100	50.9	41	43 ✓	99	64	29
Monobromoacetic acid - ug/L	U	U	0.46	0.3 ✓	0.5	U	U
Dibromoacetic acid - ug/L	1.3	U	2.6	1.2	0.52	0.8	0.47
HAA5 - ug/L	230	97.3	105	100	210	160	63
HAAF Standard - ug/L	60	60	60	60	60	60	60
Chloroform - ug/L	250	123	160	140	210	160	70
Bromoform - ug/L	U	U	U	U	U	U	U
Bromodichloromethane - ug/L	37	27.5	46	23	32	32	13
Dibromochloromethane - ug/L	3.9	5.02	11	2.5	3.3	3.7	1.4
TTHM - ug/L	290	155	210	160	240	190	84
TTHM Standard - ug/L	80	80	80	80	80	80	80
Chlorine residual			0.6	1.2	0.4	0.4	1.1

DOCKET NO. 070007-EI
GOLDER ASSOCIATES, INC.
EXHIBIT RRL-3, PAGE 40 OF 107

Cole 1
Exh 1

Trihalomethanes

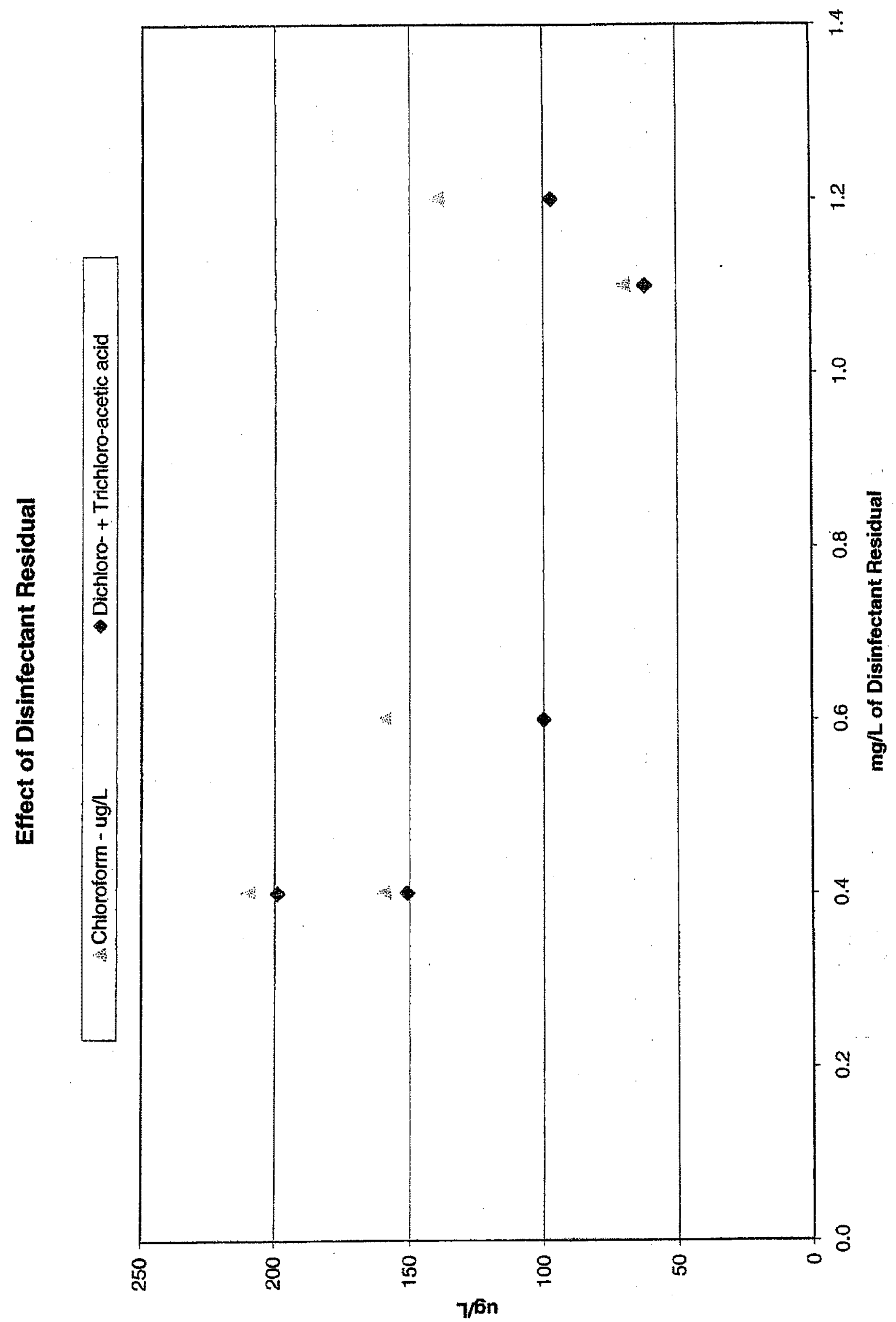


DOCKET NO. 070007-EI
GOLDER ASSOCIATES, INC.
EXHIBIT RRL-3, PAGE 41 OF 107

DOCKET NO. 070007-EI
GOLDER ASSOCIATES, INC.
EXHIBIT RRL-3, PAGE 42 OF 107

G.(c| E44 3

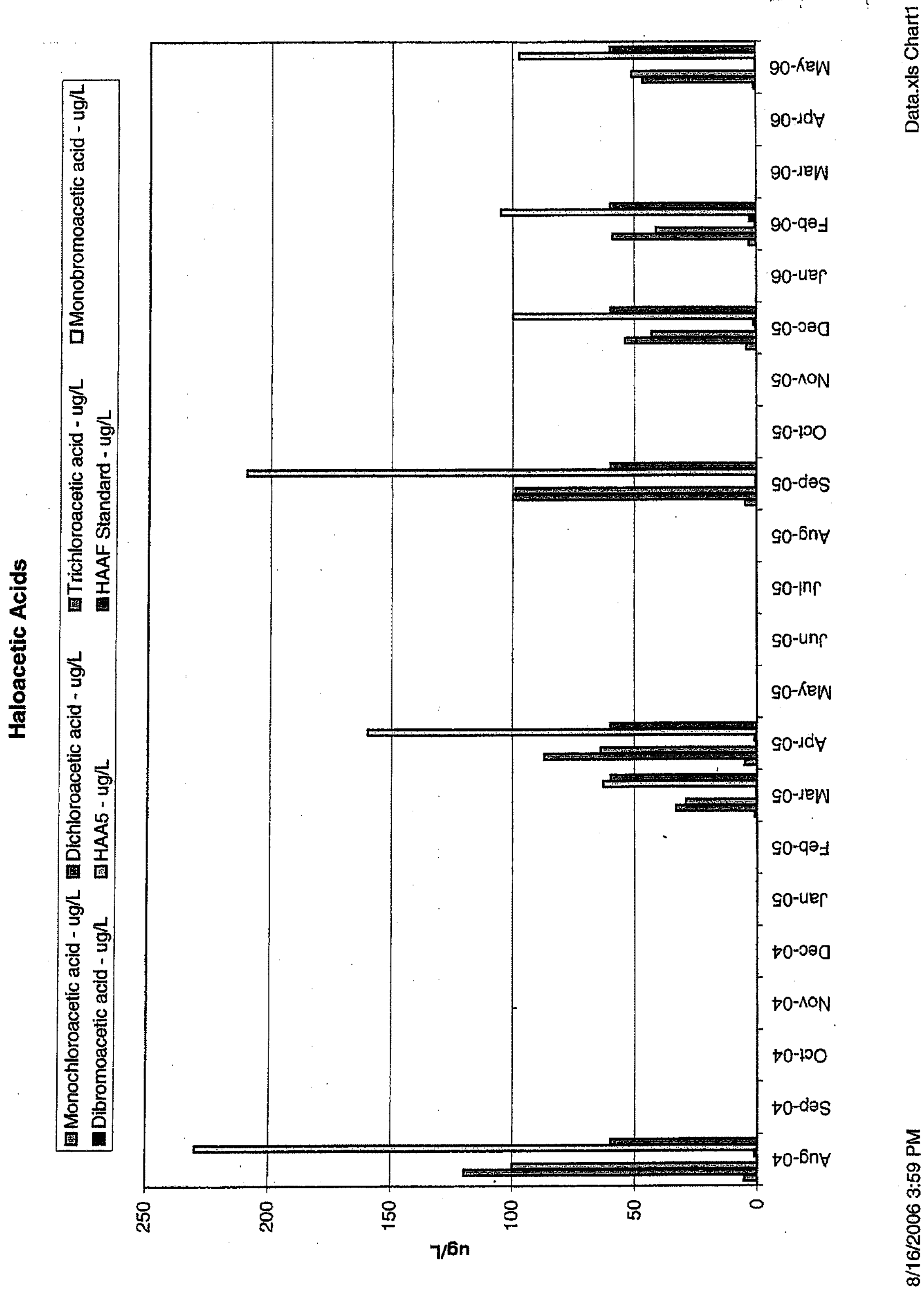
Data.xls Chart3



8/16/2006 4:21 PM

DOCKET NO. 070007-EI
GOLDER ASSOCIATES, INC.
EXHIBIT RRL-3, PAGE 43 OF 107

G1
Exh 4



Jupiter
Environmental Laboratories, Inc.

Jupiter Environmental Laboratories, Inc.
150 S. Old Dixie Highway
Jupiter, FL 33458
Phone: (561)575-0030
Fax: (561)575-4118

ANALYTICAL RESULTS

LOG# 616076
Project ID: Q.I. Analysis

Lab ID: 616076004 Date Received: 5/25/2006 Matrix: Aqueous Liquid
Sample ID: 3/4 Lab MRT Date Collected: 5/24/2006

Parameters	Results	Units	Report Limit	MDL	DF	Prepared	By	Analyzed	By	Qual	CAS
Analysis Desc: EPA 524.2 Scan by			Preparation Method: NONE Analytical Method: EPA 524.2								
Chloroform	0.123	mg/L	0.00100		1	05/26/06	ESC	05/29/06	ESC		
Bromodichloromethane	0.0275	mg/L	0.00100		1	05/26/06	ESC	05/29/06	ESC		
Chlorodibromomethane	0.00502	mg/L	0.00100		1	05/26/06	ESC	05/29/06	ESC		
Bromoform	U	mg/L	0.00100		1	05/26/06	ESC	05/29/06	ESC		
Total Trihalomethanes	0.155	mg/L	0.00100		1	05/26/06	ESC	05/29/06	ESC		
Analysis Desc EPA 552.2											
Bromoacetic acid	U	mg/L	0.00200		1	05/26/06	ESC	05/29/06	ESC		
Chloroacetic acid	U	mg/L	0.00200		1	05/26/06	ESC	05/29/06	ESC		
Dibromoacetic acid	U	mg/L	0.00200		1	05/26/06	ESC	05/29/06	ESC		
Dichloroacetic acid	0.0464	mg/L	0.00200		1	05/26/06	ESC	05/29/06	ESC		
·chloroacetic acid	0.0509	mg/L	0.00200		1	05/26/06	ESC	05/29/06	ESC		
·tal Haloacetic acids	0.0973	mg/L	0.00200		1	05/26/06	ESC	05/29/06	ESC		

FDOH# E86546
CERTIFICATE OF ANALYSIS

Jupiter
Environmental Laboratories, Inc.

Jupiter Environmental Laboratories, Inc.
150 S. Old Dixie Highway
Jupiter, FL 33458
Phone: (561)575-0030
Fax: (561)575-4118

ANALYTICAL RESULTS QUALIFIERS

LOG# 616076
Project ID: Q.I. Analysis

PARAMETER QUALIFIERS

SUBCONTRACTOR NELAC CERTIFICATION

616076 ESC = E87487

FDOH# E86546

CERTIFICATE OF ANALYSIS

Florida Department of Environmental Protection
Safe Drinking Water Program Laboratory Reporting Format

PUBLIC WATER SYSTEM INFORMATION (to be completed by sampler - Please type or print legibly)

System Name: FPL - INDIANTOWN PWS I.D. #: 4 4 3 1 1 7 4 8

System Type (check one) ☐ Community ☒ Nontransient Noncommunity ☐ Transient Noncommunity

Address: 2190 SW WARFIELD BLVD.

City: INDIANTOWN State: FL. ZIP Code: 34956

Phone #: 772-597-7211 Fax #: 772-597-7416

E-Mail Address:

SAMPLE INFORMATION (to be completed by sampler)

Sample Number: 001 Location Code (if known): MRT

Sample Date: 02/13/06 Sample Time: 3:00 PM

Sample Location (be specific): 3/4 Lab MRT Grab

Disinfectant Residual (Required when reporting results for trihalomethanes and haloacetic acids): .60 mg/L Field pH:

Sample Type (Check Only One)

- ☐ Distribution
- ☐ Entry Point (to Distribution)
- ☐ Plant Tap not for compliance with 62-550)
- ☐ Raw (at well or intake)
- ☒ Max Residence Time
- ☐ Ave Residence Time
- ☐ Near First Customer

Reason(s) for Sample (Check all that apply)

- ☐ Routine Compliance (with 62-550)
- ☐ Confirmation of MCL Exceedence*
- ☐ Composite of Multiple Sites**
- ☐ Clearance (permitting)
- ☐ Other:
- ☒ Quarterly (Which Qtr? 1ST
- ☐ Special (not for compliance with 62-550)
- ☐ Violation Resolution
- ☐ Replacement (of Invalidated Sample)

Sampling Procedure Used or Other Comments:

*See 62-550.500(6) for requirements and restrictions. Note: See 62-550.512(3) for additional requirements for Nitrate or Nitrite MCL exceedences.

** See 62-550.550(4) for requirements and attach a results page for each site.

Sampler's Name: STAN McELROY

Sampler's Phone #: 772-597-7640 Sampler's Fax #: 772-597-7416

Sampler's E-Mail Address: STAN_J_McELROY@FPL.COM

CERTIFICATION (to be completed by sampler)

I, STAN McELROY (Print Name), SR. PLT. TECH - LEAD OP. (Print Title)

do HEREBY CERTIFY that the above public water system and sample collection information is completed and correct.

Signature: S. J. McElroy Date: 4-10-06

Florida Department of Environmental Protection
Safe Drinking Water Program Laboratory Reporting Format

LABORATORY CERTIFICATION INFORMATION (to be completed by lab - Please type or print legibly)

ATTACH A CURRENT DOH ANALYTE SHEET

Lab Name: Harbor Branch Environmental Laboratories, Inc. Florida Certification #: E96080

Address: 5600 US 1 North Certification Expiration Date: 06/30/2006

Fort Pierce, FL 34946 Phone #: (772) 465-2400 Ext. 285

ANALYSIS INFORMATION (to be completed by lab) Date Sample(s) Received:: 2/14/06

PWS ID (From Page 1): 443-1748 Sample Number (From Page 1): 001

Lab Assigned Report Number or Job ID: 2023804001

Group(s) Analyzed and Results attached for compliance with Chapter 62-550, F.A.C. (Check all that apply):

Inorganics
- ☐ All 17
- ☐ Partial
- ☐ Nitrate
- ☐ Nitrite
- ☐ Asbestos Only

Synthetic Organics
- ☐ All 30
- ☐ All Except Dioxin
- ☐ Partial
- ☐ Dioxin Only

Volatile Organics
- ☐ All 21
- ☐ Partial

Radionuclides
- ☐ Single Sample
- ☐ Qtrly Composite**

Disinfection Byproducts
- ☑ Trihalomethanes
- ☑ Haloacetic Acids
- ☐ Bromate
- ☐ Chlorite

Secondaries
- ☐ All 14
- ☐ Partial

Were any analyses subcontracted? ____ Yes X No

If yes, please provide DOH certification numbers: ____________

ATTACH DOH ANALYTE SHEET FOR EACH SUBCONTRACTED LAB

CERTIFICATION

I, Cindy Cromer (Print Name), Laboratory Director (Print Title)

do HEREBY CERTIFY that all attached analytical data are correct and unless noted meet all requirements of the National Environmental Laboratory Accreditation Conference (NELAC).

Signature Cindy Cromer Date: 06-Mar-06

* Failure to provide a valid and current Florida DOH lab certification number and a current Analyte Sheet for the attached analysis results will result in rejection of the report, possible enforcement against the public water system for failure to sample, and may result in notification of the DOH Bureau of Laboratory Services.

** Please provide radiological sample dates locations for each quarter.

COMPLIANCE DETERMINATION (to be completed by DEP or DOH)

Sample Collection Info Satisfactory: ☐ Yes ☐ No Sample Analysis Info Satisfactory: ☐ Yes ☐ No

☐ Replacement Sample(s) Requested (circle or highlight group(s) above) ☐ Revised Report Requested (circle or highlight group(s) above)

☐ Additional Monitoring Required (circle or highlight group(s) above)

Reason(s): ☐ MCL(s) Exceeded ☐ Detection(s) ☐ Incomplete Report
☐ Missing Analyte Sheet(s) ☐ Location Unsatisfactory ☐ Analysis Unsatisfactory
☐ Other: ____________

Person Notified: ____________ Date Notified: ____________

Comments: ____________

Date Reviewed: ____________ DEP/DOH Reviewing Official: ____________

HARBOR BRANCH
ENVIRONMENTAL
LABORATORIES, INC.
?600 U.S. I North, Fort Pierce FL 34946
Phone: (772) 465-2400, Ext. 285 Fax: (772) 467-1584

DISINFECTION BYPRODUCTS ANALYSES

62-550.310(3)

Client:	Florida Power & Light	Report Number/ Job ID	Martin Plant DW THM/HAA5
Sample Location:	3/4 Lab MRT Grab	Disinfectant Residual (mg/L	.60
Sample Number:	2023804001	PWS ID	4431748
Sampling Date:	2/13/06 15:00		
Date Received:	2/14/06 12:35		

Contam ID	Contam Name	MCL	Units	Analysis Result	Qualifier	Analytical Method	Lab MDL	Analysis Date	Analysis Time	Lab ID
2450	Monochloroacetic Acid	[N/A]	ug/L	2.8		EPA 552.1	0.88	2/21/06	10:11 PM	E96080
2451	Dichloroacetic Acid	[N/A]	ug/L	59		EPA 552.1	1.3	2/23/06	6:46 AM	E96080
?452	Trichloroacetic acid	[N/A]	ug/L	41		EPA 552.1	0.39	2/23/06	6:46 AM	E96080
?453	Monobromoacetic Acid	[N/A]	ug/L	0.46		EPA 552.1	0.28	2/21/06	10:11 PM	E96080
2454	Dibromoacetic Acid	[N/A]	ug/L	2.6		EPA 552.1	0.18	2/21/06	10:11 PM	E96080
2456	Total Haloacetic Acids (HAA5)	[60]	ug/L							
2941	Chloroform	[N/A]	ug/L	160		EPA 524.2	2.5	2/27/06	11:15 AM	E96080
2942	Bromoform	[N/A]	ug/L	0.41 U		EPA 524.2	0.41	2/22/06	5:18 PM	E96080
2943	Bromodichloromethane	[N/A]	ug/L	46		EPA 524.2	0.25	2/22/06	5:18 PM	E96080
2944	Dibromochloromethane	[N/A]	ug/L	11		EPA 524.2	0.30	2/22/06	5:18 PM	E96080
2950	Total Trihalomethanes	[80]	ug/L							

NOTE: Do not round values. Report results to the accuracy, precision, and sensitivity of the analytical method used. Totals for haloacetic acids and total trihalomethanes will be calculated by DEP or DOH.

Reporting Format 62-550 730
Effective January 1995, Revised January 2004

Results must be reported with appropriate qualifiers in accordance with Florida Administrative Code Rule 62-160, Table 1. Results Qualified with A, F, H, N, O, T, Z, ?, *, are unacceptable for compliance with 62-550. Results qualified with a J, Q, R, or Y must be accompanied by written justification and will be evaluated on a case by case basis. To oid a monitoring violation, unacceptable results must be replaced with acceptable results from samples collected during the same monitoring peri

HARBOR BRANCH
ENVIRONMENTAL
LABORATORIES, INC.
5600 U.S. I North, Fort Pierce FL 34946
Phone: (772) 465-2400, Ext. 285 Fax: (772) 467-1584

CERTIFICATE OF ANALYSIS

[2023804]

Client: Florida Power & Light *Workorder ID:* Martin Plant DW THM/HAA5

Parameter	Qualifier	Result[1]	Units	Reporting Limit	Method	Laboratory Batch	Prep Date/Time	Analyzed Date/Time	Analyst	Lab ID
Laboratory ID: **2023804001** *Sample ID:* **3/4 Lab MRT Grab**					*Sampled:* 02/13/06 15:00 *Matrix:* Water		*Received:* 02/14/06 12:35 Results reported on Wet Weight Basis			
Bromodichloromethane		**46**	ug/L	0.25	EPA 524.2	VOC2600		02/22/06 17:18	WR	E96080
Bromoform		**0.41 U**	ug/L	0.41	EPA 524.2	VOC2600		02/22/06 17:18	WR	E96080
Chloroform		**160**	ug/L	2.5	EPA 524.2	VOC2600		02/27/06 11:15	WR	E96080
Dibromochloromethane		**11**	ug/L	0.30	EPA 524.2	VOC2600		02/22/06 17:18	WR	E96080
Total THMs		**210**	ug/L	0.50	EPA 524.2	VOC2600		02/22/06 17:18	WR	E96080
Dibromoacetic Acid		**2.6**	ug/L	0.18	EPA 552.1	PEST4659	02/22/06 15:27	02/21/06 22:11	RS	E96080
Dichloroacetic Acid		**59**	ug/L	1.3	EPA 552.1	PEST4659	02/22/06 15:27	02/23/06 6:46	RS	E96080
Monobromoacetic Acid		**0.46**	ug/L	0.28	EPA 552.1	PEST4659	02/22/06 15:27	02/21/06 22:11	RS	E96080
Monochloroacetic Acid		**2.8**	ug/L	0.88	EPA 552.1	PEST4659	02/22/06 15:27	02/21/06 22:11	RS	E96080
Total HAAs		**100**	ug/L	0.37	EPA 552.1	PEST4659	02/22/06 15:27	02/23/06 6:46	RS	E96080
Total HAAs		**110**	ug/L	0.18	EPA 552.1	PEST4659	02/22/06 15:27	02/21/06 22:11	RS	E96080
Trichloroacetic acid		**41**	ug/L	0.39	EPA 552.1	PEST4659	02/22/06 15:27	02/23/06 6:46	RS	E96080
Laboratory ID: **2023804002** *Sample ID:* **Trip Blank**					*Sampled:* 02/13/06 0:00 *Matrix:* Water		*Received:* 02/14/06 12:35 Results reported on Wet Weight Basis			
Bromodichloromethane		**0.25 U**	ug/L	0.25	EPA 524.2	VOC2600		02/22/06 17:51	WR	E96080
Bromoform		**0.41 U**	ug/L	0.41	EPA 524.2	VOC2600		02/22/06 17:51	WR	E96080
Chloroform		**0.25 U**	ug/L	0.25	EPA 524.2	VOC2600		02/22/06 17:51	WR	E96080
Dibromochloromethane		**0.30 U**	ug/L	0.30	EPA 524.2	VOC2600		02/22/06 17:51	WR	E96080
Total THMs		**0.50 U**	ug/L	0.50	EPA 524.2	VOC2600		02/22/06 17:51	WR	E96080

[1]Result Qualifiers: U = Not Detected I = Analyte detected between the Laboratory Method Detection Limit and Laboratory Reporting Limit
Applicable Florida Department of Environmental Protection Qualifiers defined below. Statement of Estimated Uncertainty available upon request.

Florida Department of Environmental Protection
Safe Drinking Water Program Laboratory Reporting Format

PUBLIC WATER SYSTEM INFORMATION (to be completed by sampler - Please type or print legibly)

System Name: FPL MARTIN PLANT PWS I.D. #: 4 4 3 1 7 4 8

System Type (check one) ☐ Community ☒ Nontransient Noncommunity ☐ Transient Noncommunity

Address: 21900 SW WARFIELD BLVD.

City: INDIANTOWN State: FL. ZIP Code: 34956

Phone #: 772-597-7211 Fax #: 772-597-7416

E-Mail Address:

SAMPLE INFORMATION (to be completed by sampler)

Sample Number: PMR 122805 Location Code (if known):

Sample Date: 12/21/05 Sample Time: 8:00 AM

Sample Location (be specific): 3/4 Lab MRT Grab

Disinfectant Residual (Required when reporting results for trihalomethanes and haloacetic acids): 1.2 mg/L Field pH:

Sample Type (Check Only One)

☐ Distribution
☐ Entry Point (to Distribution)
☐ Plant Tap not for compliance with 62-550)
☐ Raw (at well or intake)
☒ Max Residence Time
☐ Ave Residence Time
☐ Near First Customer

Reason(s) for Sample (Check all that apply)

☐ Routine Compliance (with 62-550)
☐ Confirmation of MCL Exceedence*
☐ Composite of Multiple Sites**
☐ Clearance (permitting)
☐ Other:
☒ Quarterly (Which Qtr? 4 TH
☐ Special (not for compliance with 62-550)
☐ Violation Resolution
☐ Replacement (of invalidated Sample)

Sampling Procedure Used or Other Comments:

*See 62-550.500(6) for requirements and restrictions.
Note: See 62-550.512(3) for additional requirements for Nitrate or Nitrite MCL exceedences.

** See 62-550.550(4) for requirements and attach a results page for each site.

Sampler's Name: STAN MCELROY

Sampler's Phone #: 772-597-7640 Sampler's Fax #: 772-597-7416

Sampler's E-Mail Address:

CERTIFICATION (to be completed by sampler)

I, STAN MCELROY (Print Name), LEAD OP. (Print Title)

do HEREBY CERTIFY that the above public water system and sample collection information is completed and correct.

Signature: [signature] Date: 1-09-06

Reporting Format 62-550.730 Effective January 1995, Revised January 2004

Florida Department of Environmental Protection
Safe Drinking Water Program Laboratory Reporting Format

LABORATORY CERTIFICATION INFORMATION (to be completed by lab - Please type or print legibly)

ATTACH A CURRENT DOH ANALYTE SHEET

Lab Name: Harbor Branch Environmental Laboratories, Inc. Florida Certification #: E96080

Address: 5600 US 1 North Certification Expiration Date: 06/30/2006

Fort Pierce, FL 34946 Phone #: (772) 465-2400 Ext. 285

ANALYSIS INFORMATION (to be completed by lab) Date Sample(s) Received:: 12/21/05

PWS ID (From Page 1): 4431148 Sample Number (From Page 1): ______

Lab Assigned Report Number or Job ID: 2023325001

Group(s) Analyzed and Results attached for compliance with Chapter 62-550, F.A.C. (Check all that apply):

Inorganics	Synthetic Organics	Volatile Organics	Disinfection Byproducts
☐ All 17	☐ All 30	☐ All 21	☒ Trihalomethanes
☐ Partial	☐ All Except Dioxin	☐ Partial	☒ Haloacetic Acids
☐ Nitrate	☐ Partial		☐ Bromate
☐ Nitrite	☐ Dioxin Only	**Radionuclides**	☐ Chlorite
☐ Asbestos Only		☐ Single Sample	**Secondaries**
		☐ Qtrly Composite**	☐ All 14
			☐ Partial

Were any analyses subcontracted? ___ Yes _X_ No

If yes, please provide DOH certification numbers: ______

ATTACH DOH ANALYTE SHEET FOR EACH SUBCONTRACTED LAB

CERTIFICATION

I, Cindy Cromer (Print Name), Laboratory Director (Print Title)

do HEREBY CERTIFY that all attached analytical data are correct and unless noted meet all requirements of the National Environmental Laboratory Accreditation Conference (NELAC).

Signature Cindy Cromer Date: 05-Jan-06

* Failure to provide a valid and current Florida DOH lab certification number and a current Analyte Sheet for the attached analysis results will result in rejection of the report, possible enforcement against the public water system for failure to sample, and may result in notification of the DOH Bureau of Laboratory Services.

** Please provide radiological sample dates locations for each quarter.

COMPLIANCE DETERMINATION (to be completed by DEP or DOH)

Sample Collection Info Satisfactory: ☐ Yes ☐ No Sample Analysis Info Satisfactory: ☐ Yes ☐ No

☐ Replacement Sample(s) Requested (circle or highlight group(s) above) ☐ Revised Report Requested (circle or highlight group(s) above)

☐ Additional Monitoring Required (circle or highlight group(s) above)

Reason(s): ☐ MCL(s) Exceeded ☐ Detection(s) ☐ Incomplete Report
☐ Missing Analyte Sheet(s) ☐ Location Unsatisfactory ☐ Analysis Unsatisfactory
☐ Other: ______

Person Notified: ______ Date Notified: ______

Comments: ______

Date Reviewed: ______ DEP/DOH Reviewing Official: ______

HARBOR BRANCH ENVIRONMENTAL LABORATORIES, INC.
5600 U.S. I North, Fort Pierce FL 34946
Phone (772) 465-2400, ext. 285 Fax (772) 467-1584

CERTIFICATE OF ANALYSIS

[2023325]

Client: Florida Power & Light *Workorder ID:* Martin Plant DW THM/HAA5

Laboratory ID: **2023325001**
Sample ID: **3/4 Lab MRT Grab**

Sampled: 12/21/05 8:00 *Received:* 12/21/05 12:50
Matrix: Water Results reported on Wet Weight Basis

Parameter	Qualifier Result[1]	Units	Reporting Limit	Method	Laboratory Batch	Prep Date/Time	Analyzed Date/Time	Analyst	Lab ID
Bromodichloromethane	23	ug/L	0.25	EPA 524.2	VOC2576		12/28/05 3:28	WR	E96080
Bromoform	0.41 U	ug/L	0.41	EPA 524.2	VOC2576		12/28/05 3:28	WR	E96080
Chloroform	140	ug/L	2.5	EPA 524.2	VOC2576		12/28/05 9:33	WR	E96080
Dibromochloromethane	2.5	ug/L	0.30	EPA 524.2	VOC2576		12/28/05 3:28	WR	E96080
Total THMs	160	ug/L	0.50	EPA 524.2	VOC2576		12/28/05 3:28	WR	E96080
Dibromoacetic Acid	1.2	ug/L	0.18	EPA 552.1	PEST4626	01/2/06 7:41	01/2/06 18:58	RS	E96080
Dichloroacetic Acid	54	ug/L	0.66	EPA 552.1	PEST4626	01/2/06 7:41	01/2/06 18:58	RS	E96080
Monobromoacetic Acid	0.30	ug/L	0.28	EPA 552.1	PEST4626	01/2/06 7:41	01/2/06 18:58	RS	E96080
Monochloroacetic Acid	4.0	ug/L	0.88	EPA 552.1	PEST4626	01/2/06 7:41	01/2/06 18:58	RS	E96080
Total HAAs	100	ug/L	0.18	EPA 552.1	PEST4626	01/2/06 7:41	01/2/06 18:58	RS	E96080
Trichloroacetic acid	43	ug/L	0.98	EPA 552.1	PEST4626	01/2/06 7:41	01/3/06 10:31	RS	E96080

[1]Result Qualifiers: U = Not Detected I = Analyte detected between the Laboratory Method Detection Limit and Laboratory Reporting Limit
Applicable Florida Department of Environmental Protection Qualifiers defined below. Statement of Estimated Uncertainty available upon request.

HARBOR BRANCH
ENVIRONMENTAL
LABORATORIES, INC.
00 U.S. 1 North, Fort Pierce FL 34946
one: (772) 465-2400, ext. 285 Fax: (772) 467-1584

DISINFECTION BYPRODUCTS ANALYSES
62-550.310(3)

Client: Florida Power & Light

Report Number/ Job ID Martin Plant DW THM/HAA5

Sample Location: 3/4 Lab MRT Grab

Disinfectant Residual (mg/L 1.2

Sample Number: 2023325001

PWS ID 4431748

Sampling Date: 12/21/05 8:00

Date Received: 12/21/05 12:50

Contam ID	Contam Name	MCL	Units	Analysis Result	Qualifier	Analytical Method	Lab MDL	Analysis Date	Analysis Time	Lab ID
2450	Monochloroacetic Acid	[N/A]	ug/L	**4.0**		EPA 552.1	0.88	1/02/06	6:58 PM	E96080
2451	Dichloroacetic Acid	[N/A]	ug/L	**54**		EPA 552.1	0.66	1/02/06	6;58 PM	E96080
2452	Trichloroacetic acid	[N/A]	ug/L	**43**		EPA 552.1	0.98	1/03/06	10:31 AM	E96080
2453	Monobromoacetic Acid	[N/A]	ug/L	**0.30**		EPA 552.1	0.28	1/02/06	6:58 PM	E96080
2454	Dibromoacetic Acid	[N/A]	ug/L	**1.2**		EPA 552.1	0.18	1/02/06	6:58 PM	E96080
2456	Total Haloacetic Acids (HAA5)	[60]	ug/L							
2941	Chloroform	[N/A]	ug/L	**140**		EPA 524.2	2.5	12/28/05	9:33 AM	E96080
2942	Bromoform	[N/A]	ug/L	**0.41 U**		EPA 524.2	0.41	12/28/05	3:28 AM	E96080
2943	Bromodichloromethane	[N/A]	ug/L	**23**		EPA 524.2	0.25	12/28/05	3:28 AM	E96080
2944	Dibromochloromethane	[N/A]	ug/L	**2.5**		EPA 524.2	0.30	12/28/05	3:28 AM	E96080
2950	Total Trihalomethanes	[80]	ug/L							

NOTE: Do not round values. Report results to the accuracy, precision, and sensitivity of the analytical method used. Totals for haloacetic acids and total trihalomethanes will be calculated by DEP or DOH.

Reporting Format 62-550.730
Effective January 1995, Revised January 2004

* Results must be reported with appropriate qualifiers in accordance with Florida Administrative Code Rule 62-160, Table 1. Results Qualified with A, F, H, N, O, T, Z, ?, *, are unacceptable for compliance with 62-550. Results qualified with a J, Q, R, or Y must be accompanied by written justification and will be evaluated on a case by case basis. To avoid a monitoring violation, unacceptable results must be replaced with acceptable results from samples collected during the same monitoring peri

Florida Department of Environmental Protection
Safe Drinking Water Program Laboratory Reporting Format

PUBLIC WATER SYSTEM INFORMATION (to be completed by sampler - Please type or print legibly)

stem Name: FPL MARTIN PLANT PWS I.D. #: 4 4 3 1 7 4 8

System Type (check one) ☐ Community ☒ Nontransient Noncommunity ☐ Transient Noncommunity

Address: 21900 SW WARFIELD BLVD.

City: INDIANTOWN State: FL. ZIP Code: 34956

Phone #: 772-597-7211 Fax #: 772-597-7416

E-Mail Address:

SAMPLE INFORMATION (to be completed by sampler)

Sample Number: PMR-091405 Location Code (if known):

Sample Date: 09/14/05 Sample Time: 7:00 AM

Sample Location (be specific): 3/4 Lab - MRT Grab

Disinfectant Residual (Required when reporting results for trihalomethanes and haloacetic acids): .4 mg/L Field pH:

Sample Type (Check Only One)

- ☐ Distribution
- ☐ Entry Point (to Distribution)
- ☐ Plant Tap not for compliance with 62-550)
- ☐ Raw (at well or intake)
- ☒ Max Residence Time
- ☐ Ave Residence Time
- ☐ Near First Customer

Reason(s) for Sample (Check all that apply)

- ☐ Routine Compliance (with 62-550)
- ☐ Confirmation of MCL Exceedence*
- ☐ Composite of Multiple Sites**
- ☐ Clearance (permitting)
- ☐ Other:
- ☒ Quarterly (Which Qtr? 3 RD
- ☐ Special (not for compliance with 62-550)
- ☐ Violation Resolution
- ☐ Replacement (of Invalidated Sample)

Sampling Procedure Used or Other Comments:

*See 62-550.500(6) for requirements and restrictions.
Note: See 62-550.512(3) for additional requirements for Nitrate or Nitrite MCL exceedences.

** See 62-550.550(4) for requirements and attach a results page for each site.

Sampler's Name: STAN McELROY

Sampler's Phone #: 772-597-7640 Sampler's Fax #: 772-597-7416

Sampler's E-Mail Address: STAN_J_McELROY@FPL.COM

CERTIFICATION (to be completed by sampler)

I, STAN McELROY (Print Name), LEAD OP. (Print Title)

do HEREBY CERTIFY that the above public water system and sample collection information is completed and correct.

Signature: S.J. McElroy Date: 10/10/05

Florida Department of Environmental Protection
Safe Drinking Water Program Laboratory Reporting Format

LABORATORY CERTIFICATION INFORMATION (to be completed by lab - Please type or print legibly)

ATTACH A CURRENT DOH ANALYTE SHEET

b Name: Harbor Branch Environmental Laboratories, Inc. Florida Certification #: E96080

Address: 5600 US 1 North Certification Expiration Date: 06/30/2006

Fort Pierce, FL 34946 Phone #: (772) 465-2400 Ext. 285

ANALYSIS INFORMATION (to be completed by lab) Date Sample(s) Received:: 9/14/05

PWS ID (From Page 1): ______ Sample Number (From Page 1): ______

Lab Assigned Report Number or Job ID: 2022517001

Group(s) Analyzed and Results attached for compliance with Chapter 62-550, F.A.C. (Check all that apply):

Inorganics
- ☐ All 17
- ☐ Partial
- ☐ Nitrate
- ☐ Nitrite
- ☐ Asbestos Only

Synthetic Organics
- ☐ All 30
- ☐ All Except Dioxin
- ☐ Partial
- ☐ Dioxin Only

Volatile Organics
- ☐ All 21
- ☐ Partial

Radionuclides
- ☐ Single Sample
- ☐ Qtrly Composite**

Disinfection Byproducts
- ☒ Trihalomethanes
- ☒ Haloacetic Acids
- ☐ Bromate
- ☐ Chlorite

Secondaries
- ☐ All 14
- ☐ Partial

Were any analyses subcontracted? ____ Yes X No

If yes, please provide DOH certification numbers: ______

ATTACH DOH ANALYTE SHEET FOR EACH SUBCONTRACTED LAB

CERTIFICATION

I, Cindy Cromer (Print Name) Laboratory Director (Print Title)

do HEREBY CERTIFY that all attached analytical data are correct and unless noted meet all requirements of the National Environmental Laboratory Accreditation Conference (NELAC).

Signature Cindy Cromer Date: 28-Sep-05

* Failure to provide a valid and current Florida DOH lab certification number and a current Analyte Sheet for the attached analysis results will result in rejection of the report, possible enforcement against the public water system for failure to sample, and may result in notification of the DOH Bureau of Laboratory Services.

** Please provide radiological sample dates locations for each quarter.

COMPLIANCE DETERMINATION (to be completed by DEP or DOH)

Sample Collection Info Satisfactory: ☐ Yes ☐ No Sample Analysis Info Satisfactory: ☐ Yes ☐ No

☐ Replacement Sample(s) Requested (circle or highlight group(s) above) ☐ Revised Report Requested (circle or highlight group(s) above)

☐ Additional Monitoring Required (circle or highlight group(s) above)

Reason(s): ☐ MCL(s) Exceeded ☐ Detection(s) ☐ Incomplete Report
☐ Missing Analyte Sheet(s) ☐ Location Unsatisfactory ☐ Analysis Unsatisfactory
☐ Other: ______

Person Notified: ______ Date Notified: ______

Comments: ______

Date Reviewed: ______ DEP/DOH Reviewing Official: ______

HARBOR BRANCH
ENVIRONMENTAL
LABORATORIES, INC.
600 U.S. 1 North, Fort Pierce FL 34946
Phone: (772) 465-2400, Ext. 285 Fax: (772) 467-1584

DISINFECTION BYPRODUCTS ANALYSES

62-550.310(3)

Client:	Florida Power & Light	Report Number/ Job ID	Martin Plant DW THM/HAA5
Sample Location:	3/4 Lab - MRT Grab	Disinfectant Residual (mg/L	.4
Sample Number:	2022517001	PWS ID	443-1748
Sampling Date:	9/14/05 7:00		
Date Received:	9/14/05 10:50		

Contam ID	Contam Name	MCL	Units	Analysis Result	Qualifier	Analytical Method	Lab MDL	Analysis Date	Analysis Time	Lab ID
2450	Monochloroacetic Acid	[N/A]	ug/L	4.7		EPA 552.1	0.88	9/26/05	8:15 PM	E96080
2451	Dichloroacetic Acid	[N/A]	ug/L	100		EPA 552.1	3.3	9/27/05	5:52 PM	E96080
2452	Trichloroacetic acid	[N/A]	ug/L	99		EPA 552.1	0.98	9/27/05	5:52 PM	E96080
3	Monobromoacetic Acid	[N/A]	ug/L	0.50		EPA 552.1	0.28	9/26/05	8:15 PM	E96080
2454	Dibromoacetic Acid	[N/A]	ug/L	0.52		EPA 552.1	0.18	9/26/05	8:15 PM	E96080
2456	Total Haloacetic Acids (HAA5)	[60]	ug/L							
2941	Chloroform	[N/A]	ug/L	210		EPA 524.2	2.5	9/23/05	10:31 AM	E96080
2942	Bromoform	[N/A]	ug/L	0.41	U	EPA 524.2	0.41	9/22/05	9:39 PM	E96080
2943	Bromodichloromethane	[N/A]	ug/L	32		EPA 524.2	0.25	9/22/05	9:39 PM	E96080
2944	Dibromochloromethane	[N/A]	ug/L	3.3		EPA 524.2	0.30	9/22/05	9:39 PM	E96080
2950	Total Trihalomethanes	[80]	ug/L							

NOTE: Do not round values. Report results to the accuracy, precision, and sensitivity of the analytical method used. Totals for haloacetic acids and total trihalomethanes will be calculated by DEP or DOH.

Reporting Format 62-550.730
Effective January 1995, Revised January 2004

Results must be reported with appropriate qualifiers in accordance with Florida Administrative Code Rule 62-160, Table 1. Results Qualified with A, F, H, N, O, T, Z, ?, *, are unacceptable for compliance with 62-550. Results qualified with a J, Q, R, or Y must be accompanied by written justification and will be evaluated on a case by case basis. To avoid a monitoring violation, unacceptable results must be replaced with acceptable results from samples collected during the same monitoring peri

HARBOR BRANCH
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500 U.S. 1 North, Fort Pierce FL 34946
Phone: (772) 465-2400, Ext. 285 Fax: (772) 467-1584

DISINFECTION BYPRODUCTS ANALYSES

62-550.310(3)

Client:	Florida Power & Light	Report Number/ Job ID	Martin Plant DW THM/HAA5
Sample Location:	Trip Blank	Disinfectant Residual (mg/L	.4
Sample Number:	2022517002	PWS ID	443-1148
Sampling Date:	9/14/05 0:00		
Date Received:	9/14/05 10:50		

Contam ID	Contam Name	MCL	Units	Analysis Result	Qualifier	Analytical Method	Lab MDL	Analysis Date	Analysis Time	Lab ID
2941	Chloroform	[N/A]	ug/L	**0.25 U**		EPA 524.2	0.25	9/22/05	10:12 PM	E96080
2942	Bromoform	[N/A]	ug/L	**0.41 U**		EPA 524.2	0.41	9/22/05	10:12 PM	E96080
2943	Bromodichloromethane	[N/A]	ug/L	**0.25 U**		EPA 524.2	0.25	9/22/05	10:12 PM	E96080
2944	Dibromochloromethane	[N/A]	ug/L	**0.30 U**		EPA 524.2	0.30	9/22/05	10:12 PM	E96080
2950	Total Trihalomethanes	[80]	ug/L							

NOTE: Do not round values. Report results to the accuracy, precision, and sensitivity of the analytical method used. Totals for haloacetic acids and total trihalomethanes will be calculated by DEP or DOH.

Reporting Format 62-550.730
Effective January 1995, Revised January 2004

Results must be reported with appropriate qualifiers in accordance with Florida Administrative Code Rule 62-160, Table 1. Results Qualified with A, F, H, N, O, T, Z, ?, *, are acceptable for compliance with 62-550. Results qualified with a J, Q, R, or Y must be accompanied by written justification and will be evaluated on a case by case basis. To avoid a monitoring violation, unacceptable results must be replaced with acceptable results from samples collected during the same monitoring peri

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Tel: (772) 465-2400, Ext. 285 Fax: (772) 467-1584

CERTIFICATE OF ANALYSIS

[2022517]

Client: Florida Power & Light *Workorder ID:* Martin Plant DW THM/HAA5

Parameter	Qualifier	Result[1]	Units	Reporting Limit	Method	Laboratory Batch	Prep Date/Time	Analyzed Date/Time	Analyst	Lab ID
Laboratory ID: **2022517001** *Sample ID:* **3/4 Lab - MRT Grab**					*Sampled: 09/14/05 7:00* *Matrix: Water*		*Received: 09/14/05 10:50* Results reported on Wet Weight Basis			
Bromodichloromethane		**32**	ug/L	0.25	EPA 524.2	VOC2539		09/22/05 21:39	WR	E96080
Bromoform		**0.41 U**	ug/L	0.41	EPA 524.2	VOC2539		09/22/05 21:39	WR	E96080
Chloroform		**210**	ug/L	2.5	EPA 524.2	VOC2539		09/23/05 10:31	WR	E96080
Dibromochloromethane		**3.3**	ug/L	0.30	EPA 524.2	VOC2539		09/22/05 21:39	WR	E96080
Total THMs		**240**	ug/L	0.50	EPA 524.2	VOC2539		09/22/05 21:39	WR	E96080
Dibromoacetic Acid		**0.52**	ug/L	0.18	EPA 552.1	PEST4569	09/26/05 7:13	09/26/05 20:15	RS	E96080
Dichloroacetic Acid		**100**	ug/L	3.3	EPA 552.1	PEST4569	09/26/05 7:13	09/27/05 17:52	RS	E96080
Monobromoacetic Acid		**0.50**	ug/L	0.28	EPA 552.1	PEST4569	09/26/05 7:13	09/26/05 20:15	RS	E96080
Monochloroacetic Acid		**4.7**	ug/L	0.88	EPA 552.1	PEST4569	09/26/05 7:13	09/26/05 20:15	RS	E96080
Total HAAs		**210**	ug/L	0.18	EPA 552.1	PEST4569	09/26/05 7:13	09/26/05 20:15	RS	E96080
Trichloroacetic acid		**99**	ug/L	0.98	EPA 552.1	PEST4569	09/26/05 7:13	09/27/05 17:52	RS	E96080
Laboratory ID: **2022517002** *Sample ID:* **Trip Blank**					*Sampled: 09/14/05 0:00* *Matrix: Water*		*Received: 09/14/05 10:50* Results reported on Wet Weight Basis			
Bromodichloromethane		**0.25 U**	ug/L	0.25	EPA 524.2	VOC2539		09/22/05 22:12	WR	E96080
Bromoform		**0.41 U**	ug/L	0.41	EPA 524.2	VOC2539		09/22/05 22:12	WR	E96080
roform		**0.25 U**	ug/L	0.25	EPA 524.2	VOC2539		09/22/05 22:12	WR	E96080
Dibromochloromethane		**0.30 U**	ug/L	0.30	EPA 524.2	VOC2539		09/22/05 22:12	WR	E96080
Total THMs		**0.50 U**	ug/L	0.50	EPA 524.2	VOC2539		09/22/05 22:12	WR	E96080

[1]Result Qualifiers: U = Not Detected I = Analyte detected between the Laboratory Method Detection Limit and Laboratory Reporting Limit
Applicable Florida Department of Environmental Protection Qualifiers defined below. Statement of Estimated Uncertainty available upon request.

Florida Department of Environmental Protection
Safe Drinking Water Program Laboratory Reporting Format

PUBLIC WATER SYSTEM INFORMATION (to be completed by sampler - Please type or print legibly)

System Name: FPL MARTIN PLANT PWS I.D. #: 4 4 3 1 7 4 8

System Type (check one) ☐ Community ☒ Nontransient Noncommunity ☐ Transient Noncommunity

Address: 21900 SW WARFIELD BLVD.

City: INDIANTOWN State: FL. ZIP Code: 34956

Phone #: 772-597-7211 Fax #: 772-597-7416

E-Mail Address:

SAMPLE INFORMATION (to be completed by sampler)

Sample Number: PMR-041205 Location Code (if known):

Sample Date: 04/12/05 Sample Time: 1:00 PM

Sample Location (be specific): 3/4 Lab - MRT Grab

Disinfectant Residual (Required when reporting results for trihalomethanes and haloacetic acids): .4 mg/L Field pH:

Sample Type (Check Only One)
- ☐ Distribution
- ☐ Entry Point (to Distribution)
- ☐ Plant Tap not for compliance with 62-550)
- ☐ Raw (at well or intake)
- ☒ Max Residence Time
- ☐ Ave Residence Time
- ☐ Near First Customer

Reason(s) for Sample (Check all that apply)
- ☐ Routine Compliance (with 62-550)
- ☐ Confirmation of MCL Exceedence*
- ☐ Composite of Multiple Sites**
- ☐ Clearance (permitting)
- ☐ Other:
- ☒ Quarterly (Which Qtr? 2ND
- ☐ Special (not for compliance with 62-550)
- ☐ Violation Resolution
- ☐ Replacement (of invalidated Sample)

Sampling Procedure Used or Other Comments:

*See 62-550.500(6) for requirements and restrictions.
Note: See 62-550.512(3) for additional requirements for Nitrate or Nitrite MCL exceedences.

** See 62-550.550(4) for requirements and attach a results page for each site.

Sampler's Name: STAN MCELROY

Sampler's Phone #: 772-597-7640 Sampler's Fax #: 772-597-7416

Sampler's E-Mail Address: STAN_J_MCELROY@FPL.COM

CERTIFICATION (to be completed by sampler)

I, STAN MCELROY (Print Name), LEAD OPERATOR (Print Title)

do HEREBY CERTIFY that the above public water system and sample collection information is completed and correct.

Signature: [signature] Date: 7-6-05

Florida Department of Environmental Protection
Safe Drinking Water Program Laboratory Reporting Format

LABORATORY CERTIFICATION INFORMATION (to be completed by lab - Please type or print legibly)

ATTACH A CURRENT DOH ANALYTE SHEET

Lab Name: Harbor Branch Environmental Laboratories, Inc. Florida Certification #: E96080

Address: 5600 US 1 North Certification Expiration Date: 06/30/2005

Fort Pierce, FL 34946 Phone #: (772) 465-2400 Ext. 285

ANALYSIS INFORMATION (to be completed by lab) Date Sample(s) Received:: 4/13/05

PWS ID (From Page 1): ______ Sample Number (From Page 1): ______

Lab Assigned Report Number or Job ID: 2021241001

Group(s) Analyzed and Results attached for compliance with Chapter 62-550, F.A.C. (Check all that apply):

Inorganics
- ☐ All 17
- ☐ Partial
- ☐ Nitrate
- ☐ Nitrite
- ☐ Asbestos Only

Synthetic Organics
- ☐ All 30
- ☐ All Except Dioxin
- ☐ Partial
- ☐ Dioxin Only

Volatile Organics
- ☐ All 21
- ☐ Partial

Radionuclides
- ☐ Single Sample
- ☐ Qtrly Composite**

Disinfection Byproducts
- ☒ Trihalomethanes
- ☒ Haloacetic Acids
- ☐ Bromate
- ☐ Chlorite

Secondaries
- ☐ All 14
- ☐ Partial

Were any analyses subcontracted? ____ Yes X No

If yes, please provide DOH certification numbers: ______
ATTACH DOH ANALYTE SHEET FOR EACH SUBCONTRACTED LAB

CERTIFICATION

I, Cindy Cromer, Laboratory Director
(Print Name) (Print Title)
do HEREBY CERTIFY that all attached analytical data are correct and unless noted meet all requirements of the National Environmental Laboratory Accreditation Conference (NELAC).

Signature Cindy Cromer Date: 26-Apr-05

* Failure to provide a valid and current Florida DOH lab certification number and a current Analyte Sheet for the attached analysis results will result in rejection of the report, possible enforcement against the public water system for failure to sample, and may result in notification of the DOH Bureau of Laboratory Services.
** Please provide radiological sample dates locations for each quarter.

COMPLIANCE DETERMINATION (to be completed by DEP or DOH)

Sample Collection Info Satisfactory: ☐ Yes ☐ No Sample Analysis Info Satisfactory: ☐ Yes ☐ No

☐ Replacement Sample(s) Requested (circle or highlight group(s) above) ☐ Revised Report Requested (circle or highlight group(s) above)

☐ Additional Monitoring Required (circle or highlight group(s) above)

Reason(s): ☐ MCL(s) Exceeded ☐ Detection(s) ☐ Incomplete Report
☐ Missing Analyte Sheet(s) ☐ Location Unsatisfactory ☐ Analysis Unsatisfactory
☐ Other: ______

Person Notified: ______ Date Notified: ______

Comments: ______

Date Reviewed: ______ DEP/DOH Reviewing Official: ______

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ENVIRONMENTAL
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JO U.S. I North, Fort Pierce FL 34946
Phone: (772) 465-2400, Ext. 285 Fax: (772) 467-1584

DISINFECTION BYPRODUCTS ANALYSES

62-550.310(3)

Client:	Florida Power & Light	Report Number/ Job ID	Martin Plant DW THM/HAA5
Sample Location:	3/4 Lab - MRT Grab	Disinfectant Residual (mg/L	
Sample Number:	2021241001	PWS ID	
Sampling Date:	4/12/05 13:00		
Date Received:	4/13/05 11:25		

Contam ID	Contam Name	MCL	Units	Analysis Result	Qualifier	Analytical Method	Lab MDL	Analysis Date	Analysis Time	Lab ID
2450	Monochloroacetic Acid	[N/A]	ug/L	4.9		EPA 552.1	0.88	4/22/05	4:22 PM	E96080
2451	Dichloroacetic Acid	[N/A]	ug/L	87		EPA 552.1	3.3	4/22/05	6:30 PM	E96080
452	Trichloroacetic acid	[N/A]	ug/L	64		EPA 552.1	0.98	4/22/05	6:30 PM	E96080
2453	Monobromoacetic Acid	[N/A]	ug/L	0.28 U		EPA 552.1	0.28	4/22/05	4:22 PM	E96080
2454	Dibromoacetic Acid	[N/A]	ug/L	0.80		EPA 552.1	0.18	4/22/05	4:22 PM	E96080
2456	Total Haloacetic Acids (HAA5)	[60]	ug/L							
2941	Chloroform	[N/A]	ug/L	160		EPA 524.2	1.2	4/20/05	4:43 PM	E96080
2942	Bromoform	[N/A]	ug/L	0.41 U		EPA 524.2	0.41	4/19/05	11:44 PM	E96080
2943	Bromodichloromethane	[N/A]	ug/L	32		EPA 524.2	0.25	4/19/05	11:44 PM	E96080
2944	Dibromochloromethane	[N/A]	ug/L	3.7		EPA 524.2	0.30	4/19/05	11:44 PM	E96080
2950	Total Trihalomethanes	[80]	ug/L							

NOTE: Do not round values. Report results to the accuracy, precision, and sensitivity of the analytical method used. Totals for haloacetic acids and total trihalomethanes will be calculated by DEP or DOH.

Reporting Format 62-550.730
Effective January 1995, Revised January 2004

* Results must be reported with appropriate qualifiers in accordance with Florida Administrative Code Rule 62-160, Table 1. Results Qualified with A, F, H, N, O, T, Z, ?, *, are unacceptable for compliance with 62-550. Results qualified with a J, Q, R, or Y must be accompanied by written justification and will be evaluated on a case by case basis. To avoid a monitoring violation, unacceptable results must be replaced with acceptable results from samples collected during the same monitoring peri

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ENVIRONMENTAL
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5600 U.S. 1 North, Fort Pierce FL 34946
Phone (772) 465-2400, Ext. 285 Fax: (772) 467-1584

Quality Control Summary

Client: Florida Power & Light
Workorder ID: Martin Plant DW THM/HAA5 **[2021241]**
Received: 4/13/05 11:25

MB=Method Blank LCS=Laboratory Control Sample LCSD=Laboratory Control Sample Duplicate MS=Matrix Spike MSD=Matrix Spike Duplicate DUP=Sample Duplicate

Method Narratives (If Applicable)

HBEL Sample Number	Sample ID	Analytical Method	Description

Quality Control Summary

Method	HBEL Batch	Analyte	Analytical Issue
EPA 552.1			
	PEST4475		
	2021241001	Dichloroacetic Acid	Accuracy - Outside acceptance limits in the MS.
	2021241001	Dichloroacetic Acid	Accuracy - Outside acceptance limits in the MSD.
	2021241001	Dichloroacetic Acid	Precision - Outside acceptance limits between the MS and MSD.

The above due to matrix effects. Accuracy/Precision demonstrated with other QC samples.

ENVIRONMENTAL LABORATORIES

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Phone: (772) 465-2400, Ext. 285 Fax: (772) 467-1584

CERTIFICATE OF ANALYSIS

[2021241]

Client: Florida Power & Light *Workorder ID:* Martin Plant DW THM/HAA5

Laboratory ID: **2021241001**
Sample ID: **3/4 Lab - MRT Grab**

Sampled: 04/12/05 13:00 *Received:* 04/13/05 11:25
Matrix: Water Results reported on Wet Weight Basis

Parameter	Qualifier	Result[1]	Units	Reporting Limit	Method	Laboratory Batch	Prep Date/Time	Analyzed Date/Time	Analyst	Lab ID
Bromodichloromethane		32	ug/L	0.25	EPA 524.2	VOC2471		04/19/05 23:44	WR	E96080
Bromoform		0.41 U	ug/L	0.41	EPA 524.2	VOC2471		04/19/05 23:44	WR	E96080
Chloroform		160	ug/L	1.2	EPA 524.2	VOC2471		04/20/05 16:43	WR	E96080
Dibromochloromethane		3.7	ug/L	0.30	EPA 524.2	VOC2471		04/19/05 23:44	WR	E96080
Total THMs		190	ug/L	0.50	EPA 524.2	VOC2471		04/19/05 23:44	WR	E96080
Dibromoacetic Acid		0.80	ug/L	0.18	EPA 552.1	PEST4475	04/22/05 9:12	04/22/05 16:22	RS	E96080
Dichloroacetic Acid		87	ug/L	3.3	EPA 552.1	PEST4475	04/22/05 9:12	04/22/05 18:30	RS	E96080
Monobromoacetic Acid		0.28 U	ug/L	0.28	EPA 552.1	PEST4475	04/22/05 9:12	04/22/05 16:22	RS	E96080
Monochloroacetic Acid		4.9	ug/L	0.88	EPA 552.1	PEST4475	04/22/05 9:12	04/22/05 16:22	RS	E96080
Total HAAs		160	ug/L	0.18	EPA 552.1	PEST4475	04/22/05 9:12	04/22/05 16:22	RS	E96080
Trichloroacetic acid		64	ug/L	0.98	EPA 552.1	PEST4475	04/22/05 9:12	04/22/05 18:30	RS	E96080

[1]Result Qualifiers: U = Not Detected I = Analyte detected between the Laboratory Method Detection Limit and Laboratory Reporting Limit
Applicable Florida Department of Environmental Protection Qualifiers defined below. Statement of Estimated Uncertainty available upon request.

HARBOR BRANCH
ENVIRONMENTAL
LABORATORIES, INC.
5600 U.S. 1 North, Fort Pierce FL 34946
Phone: (772) 465-2400, Ext. 285 Fax: (772) 467-1584

March 30, 2005

To: Stan McElroy
Florida Power & Light
Martin Plant PO Box 176
Indiantown, FL 34956

Client: Florida Power & Light
Workorder ID: Drinking WaterTHM/HAA5 **[2021035]**
Received: 3/15/05 11:30

Dear Stan McElroy;

Analytical results presented in this report have been reviewed for compliance with the HARBOR BRANCH Environmental Laboratories Inc.'s (HBEL) Quality Systems Manual and have been determined to meet applicable Method guidelines and Standards referenced in the July 2002 National Environmental Laboratory Accreditation Program (NELAP) Quality Manual unless otherwise noted. The Analytical Results within these report pages reflect the values obtained from tests performed on Samples As Received by the laboratory unless indicated differently.

FDOH Safe Drinking Water Act, Clean Water Act and RCRA Certification #'s:

E96080, E83509, E85370, E84418

~~Questions regarding this report should be directed to the Report Signatory at (772) 465-2400~~ Ext. 285 referencing the HBEL Workorder ID [Number].

Respectfully submitted,

Cindy Cromer
Technical Director or Designee

HARBOR BRANCH
ENVIRONMENTAL
LABORATORIES, INC.
5600 U.S. 1 North, Fort Pierce FL 34946
Phone: (772) 465-2400, ext. 295 Fax: (772) 467-1584

Method Narratives/FDEP Data Qualifiers

Client: Florida Power & Light
Workorder ID: Drinking WaterTHM/HAA5 **[2021035]**
Received: 3/15/05 11:30

MB=Method Blank LCS=Laboratory Control Sample LCSD=Laboratory Control Sample Duplicate MS=Matrix Spike MSD=Matrix Spike Duplicate DUP=Sample Duplicate

Method Narratives (If Applicable)

HBEL Sample Number	Sample ID	Analytical Method	Description

Data Qualifiers (If Applicable)

HBEL Sample Number	Sample ID	Parameter	Method	Qualifier Code	Qualifier Definition

Quality Control Summary

Method	HBEL Batch	Analyte	Analytical Issue

Florida Department of Environmental Protection
Safe Drinking Water Program Laboratory Reporting Format

PUBLIC WATER SYSTEM INFORMATION (to be completed by sampler - Please type or print legibly)

System Name: FPL-MARTIN PLANT PWS I.D. #: 4 4 3 1 7 4 8

System Type (check one) ☐ Community ☒ Nontransient Noncommunity ☐ Transient Noncommunity

Address: 21900 SW WARFIELD BLVD

City: INDIANTOWN State: FL. ZIP Code: 34956

Phone #: 772-597-7211 Fax #: 772-597-7416

E-Mail Address:

SAMPLE INFORMATION (to be completed by sampler)

Sample Number: 001 Location Code (if known): 3/4 LAB MRT

Sample Date: 03/15/05 Sample Time: 7:10 AM

Sample Location (be specific): 3/4 Lab-MRT Grab

Disinfectant Residual (Required when reporting results for trihalomethanes and haloacetic acids 1.1 mg/L Field pH:

Sample Type (Check Only One)

☐ Distribution
☐ Entry Point (to Distribution)
☐ Plant Tap not for compliance with 62-550)
☐ Raw (at well or intake)
☒ Max Residence Time
☐ Ave Residence Time
☐ Near First Customer

Reason(s) for Sample (Check all that apply)

☒ Routine Compliance (with 62-550)
☐ Confirmation of MCL Exceedence*
☐ Composite of Multiple Sites**
☐ Clearance (permitting)
☐ Other:

☒ Quarterly (Which Qtr? 1ST
☐ Special (not for compliance with 62-550)
☐ Violation Resolution
☐ Replacement (of invalidated Sample)

Sampling Procedure Used or Other Comments:

*See 62-550.500(6) for requirements and restrictions.
Note: See 62-550.512(3) for additional requirements for Nitrate or Nitrite MCL exceedences.

** See 62-550.550(4) for requirements and attach a results page for each site.

Sampler's Name: S. McELROY

Sampler's Phone #: 772-597-7840 Sampler's Fax #: 772-597-7416

Sampler's E-Mail Address:

CERTIFICATION (to be completed by sampler)

I, STAN McELROY, LEAD OPERATOR
Print Name Print Title

do HEREBY CERTIFY that the above public water system and sample collection information is completed and correct.

Signature: S. J. McElroy Date: 4/5/05

Florida Department of Environmental Protection
Safe Drinking Water Program Laboratory Reporting Format

LABORATORY CERTIFICATION INFORMATION (to be completed by lab - Please type or print legibly)

ATTACH A CURRENT DOH ANALYTE SHEET

Lab Name: Harbor Branch Environmental Laboratories, Inc. Florida Certification #: E96080

Address: 5600 US 1 North Certification Expiration Date: 06/30/2005

Fort Pierce, FL 34946 Phone #: (772) 465-2400 Ext. 285

ANALYSIS INFORMATION (to be completed by lab) Date Sample(s) Received:: 3/15/05

PWS ID (From Page 1): ______ Sample Number (From Page 1): ______

Lab Assigned Report Number or Job ID: 2021035001

Group(s) Analyzed and Results attached for compliance with Chapter 62-550, F.A.C. (Check all that apply):

Inorganics	Synthetic Organics	Volatile Organics	Disinfection Byproducts
☐ All 17	☐ All 30	☐ All 21	☒ Trihalomethanes
☐ Partial	☐ All Except Dioxin	☐ Partial	☒ Haloacetic Acids
☐ Nitrate	☐ Partial		☐ Bromate
☐ Nitrite	☐ Dioxin Only	**Radionuclides**	☐ Chlorite
☐ Asbestos Only		☐ Single Sample	**Secondaries**
		☐ Qtrly Composite**	☐ All 14
			☐ Partial

Were any analyses subcontracted? ___ Yes X No

If yes, please provide DOH certification numbers: None

ATTACH DOH ANALYTE SHEET FOR EACH SUBCONTRACTED LA

CERTIFICATION

I, Cindy Cromer (Print Name), Laboratory Director (Print Title)

do HEREBY CERTIFY that all attached analytical data are correct and unless noted meet all requirements of the National Environmental Laboratory Accreditation Conference (NELAC).

Signature Cindy Cromer Date: 30-Mar-05

* Failure to provide a valid and current Florida DOH lab certification number and a current Analyte Sheet for the attached analysis results will result in rejection of the report, possible enforcement against the public water system for failure to sample, and may result in notification of the DOH ~~Bureau of Laboratory Services.~~

** Please provide radiological sample dates locations for each quarter.

COMPLIANCE DETERMINATION (to be completed by DEP or DOH)

Sample Collection Info Satisfactory: ☐ Yes ☐ No Sample Analysis Info Satisfactory: ☐ Yes ☐ No

☐ Replacement Sample(s) Requested (circle or highlight group(s) above) ☐ Revised Report Requested (circle or highlight group(s) above)

☐ Additional Monitoring Required (circle or highlight group(s) above)

Reason(s): ☐ MCL(s) Exceeded ☐ Detection(s) ☐ Incomplete Report
☐ Missing Analyte Sheet(s) ☐ Location Unsatisfactory ☐ Analysis Unsatisfactory
☐ Other: ______

Person Notified: ______ Date Notified: ______

Comments: ______

Date Reviewed: ______ DEP/DOH Reviewing Official: ______

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LABORATORIES, INC.
5600 U.S. 1 North, Fort Pierce FL 34946
Phone: (772) 465-2400, Ext. 285 Fax: (772) 467-1584

DISINFECTION BYPRODUCTS ANALYSES

62-550.310(3)

Client:	Florida Power & Light	Report Number/ Job ID	Drinking WaterTHM/HAA5
Sample Location:	3/4 Lab-MRT Grab	Disinfectant Residual (mg/L	
Sample Number:	2021035001	PWS ID	
Sampling Date:	3/15/05 7:10		
Date Received:	3/15/05 11:30		

Contam ID	Contam Name	MCL	Units	Analysis Result	Qualifier	Analytical Method	Lab MDL	Analysis Date	Analysis Time	Lab ID
2450	Monochloroacetic Acid	[N/A]	ug/L	**1.8 U**		EPA 552.1	1.8	3/22/05	4:13 PM	E96080
2451	Dichloroacetic Acid	[N/A]	ug/L	**33**		EPA 552.1	1.3	3/22/05	4:13 PM	E96080
2452	Trichloroacetic acid	[N/A]	ug/L	**29**		EPA 552.1	0.39	3/22/05	4:13 PM	E96080
2450	Monobromoacetic Acid	[N/A]	ug/L	**0.56 U**		EPA 552.1	0.56	3/22/05	4:13 PM	E96080
2454	Dibromoacetic Acid	[N/A]	ug/L	**0.47**		EPA 552.1	0.37	3/22/05	4:13 PM	E96080
2456	Total Haloacetic Acids (HAA5)	[60]	ug/L							
2941	Chloroform	[N/A]	ug/L	**70**		EPA 524.2	0.25	3/28/05	6:41 PM	E96080
2942	Bromoform	[N/A]	ug/L	**0.41 U**		EPA 524.2	0.41	3/28/05	6:41 PM	E96080
2943	Bromodichloromethane	[N/A]	ug/L	**13**		EPA 524.2	0.25	3/28/05	6:41 PM	E96080
2944	Dibromochloromethane	[N/A]	ug/L	**1.4**		EPA 524.2	0.30	3/28/05	6:41 PM	E96080
2950	Total Trihalomethanes	[80]	ug/L							

NOTE: Do not round values. Report results to the accuracy, precision, and sensitivity of the analytical method used. Totals for haloacetic acids and total trihalomethanes will be calculated by DEP or DOH.

Reporting Format 62-550.730
Effective January 1995, Revised January 2004

* Results must be reported with appropriate qualifiers in accordance with Florida Administrative Code Rule 62-160, Table 1. Results Qualified with A, F, H, N, O, T, Z, ?, *, unacceptable for compliance with 62-550. Results qualified with a J, Q, R, or Y must be accompanied by written justification and will be evaluated on a case by case basis. avoid a monitoring violation, unacceptable results must be replaced with acceptable results from samples collected during the same monitoring peri

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Agreement to Perform Services

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✓ FDOH # E96080 5600 U.S. 1 North Fort Pierce, FL 34946
___ FDOH # E85370 307 Coolidge Avenue Lehigh Acres, FL 33936
___ FDOH # E83509 255 Enterprise Rd., Suite 1 Deltona, FL 32725
___ FDOH # E84418 2514 Osawaw Blvd. Spring Hill, FL 34607

ACCREDITED IN ACCORDANCE WITH nelac

Company: FPL - MARTIN
Address: 21900 SW WARFIELD BLVD.
INDIANTOWN, FL Zip: 34956
Phone: 772-597-7211 Fax: 772-597-7416
Client Contact: WILLIE WELCH
Project Name: POTABLE THM-HAAS
Sampled By: S. MCELROY

Method(s) of Shipment: HBEL
e-mail:

✓ Standard Laboratory Turn Around Time
Or
Rush in ____ Business Days
Requires Laboratory Approval

For Lab Use Only
Temperature Checked (Y) N
Custody Seals Intact Y N/a
pH Checked Y N

LAB # 2021035

PRESERVATIVE: Na2S2O3 | NH4Cl

ANALYSES REQUESTED: THM | HAAS

Preservation Key
H=Hydrochloric Acid P=Phosphoric Acid
N=Nitric Acid ST=Sodium Thiosulfate
S=Sulfuric Acid
SH=Sodium Hydroxide U=Unpreserved

LAB ID	COLLECTION DATE	COLLECTION TIME	Sample Type*	MATRIX**	# Containers	SAMPLE DESCRIPTION As Will Appear On Report	THM	HAAS							COMMENTS
001	3-15-05	0710	G	DW	3	3/4 LAB - MRT	✓								1.1 ppm Cl2
~~002~~ 001	3-15-05	0710	G	DW	1	3/4 LAB - MRT		✓							1.1 ppm Cl2

* Sample Type: G=Grab C=Composite
** Matrix: S=Solid SL=Sludge DW=Drinking Water GW=Ground Water SW=Surface Water WW=Wastewater M=Marine

Report Page 1 of 1

RELINQUISHED BY S. McElroy	RELINQUISHED BY	RELINQUISHED BY
DATE/TIME 3-15-05	DATE/TIME	DATE/TIME
RECEIVED BY Craig Mueller	RECEIVED BY	RECEIVED FOR HBEL CUSTODY BY Craig Mueller
DATE/TIME 3/15/05 8:20	DATE/TIME	DATE/TIME 3-15-05 11:30

Distribution: WHITE with REPORT; YELLOW for FILE; PINK to CLIENT; GOLD for SAMPLER

CHAIN PAGE 1 of 1

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Volatile Organic Analysis
62 - 550.310 (2) (b)
(PWS028)

Client: Florida Power & Light   Workorder: Potable Tri-Annual Samples

Sample Location: Potable P.O.E. Grab

Sample Number: 2019680001

Sampling Date: 8/25/04 15:00

Preservative: 1:1 Hydrochloric Acid and Sodium Thiosulfate

Date Received: 8/26/04 12:05

ID	Parameter	MCL	Result		Method	MDL	Date	Lab ID
2378	1,2,4-Trichlorobenzene	[70]	**0.41 U**	ug/L	EPA 524.2	0.41	9/01/04	E96080
2380	cis-1,2-Dichloroethene	[70]	**0.21 U**	ug/L	EPA 524.2	0.21	9/01/04	E96080
2955	Total Xylenes	[10000]	**0.46 U**	ug/L	EPA 524.2	0.46	9/01/04	E96080
2964	Methylene chloride	[5]	**0.23 U**	ug/L	EPA 524.2	0.23	9/01/04	E96080
2968	1,2-Dichlorobenzene	[600]	**0.21 U**	ug/L	EPA 524.2	0.21	9/01/04	E96080
2969	1,4-Dichlorobenzene	[75]	**0.23 U**	ug/L	EPA 524.2	0.23	9/01/04	E96080
2976	Vinyl chloride	[1]	**0.32 U**	ug/L	EPA 524.2	0.32	9/01/04	E96080
2977	1,1-Dichloroethene	[7]	**0.23 U**	ug/L	EPA 524.2	0.23	9/01/04	E96080
2979	trans-1,2-Dichloroethene	[100]	**0.35 U**	ug/L	EPA 524.2	0.35	9/01/04	E96080
2980	1,2-Dichloroethane	[3]	**0.29 U**	ug/L	EPA 524.2	0.29	9/01/04	E96080
2981	1,1,1-Trichloroethane	[200]	**0.21 U**	ug/L	EPA 524.2	0.21	9/01/04	E96080
2982	Carbon tetrachloride	[3]	**0.24 U**	ug/L	EPA 524.2	0.24	9/01/04	E96080
2983	1,2-Dichloropropane	[5]	**0.40 U**	ug/L	EPA 524.2	0.40	9/01/04	E96080
2984	Trichloroethene	[3]	**0.36 U**	ug/L	EPA 524.2	0.36	9/01/04	E96080
2985	1,1,2-Trichloroethane	[5]	**0.44 U**	ug/L	EPA 524.2	0.44	9/01/04	E96080
2987	Tetrachloroethene	[3]	**0.24 U**	ug/L	EPA 524.2	0.24	9/01/04	E96080
2989	Chlorobenzene	[100]	**0.30 U**	ug/L	EPA 524.2	0.30	9/01/04	E96080
2990	Benzene	[1]	**0.20 U**	ug/L	EPA 524.2	0.20	9/01/04	E96080
2991	Toluene	[1000]	**0.22 U**	ug/L	EPA 524.2	0.22	9/01/04	E96080
2992	Ethylbenzene	[700]	**0.21 U**	ug/L	EPA 524.2	0.21	9/01/04	E96080
2996	Styrene	[70]	**0.21 U**	ug/L	EPA 524.2	0.21	9/01/04	E96080

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Volatile Organic Analysis
62 - 550.310 (2) (b)
(PWS028)

Client: Florida Power & Light   Workorder: Martin Plant DW Scan

Sample Location: Potable POE Grab

Sample Number: 2008810001

Sampling Date: 10/31/01 15:30

Preservative: 1:1 Hydrochloric Acid and Sodium Thiosulfate

Date Received: 11/01/01 9:55

ID	Parameter	MCL	Result		Method	MDL	Date	Lab ID
2378	1,2,4-Trichlorobenzene	[70]	ND	ug/L	EPA 524.2	0.37	11/08/01	E96080
2380	cis-1,2-Dichloroethene	[70]	ND	ug/L	EPA 524.2	0.23	11/08/01	E96080
2955	Total Xylenes	[10000]	ND	ug/L	EPA 524.2	0.30	11/08/01	E96080
2964	Methylene chloride	[5]	ND	ug/L	EPA 524.2	0.49	11/08/01	E96080
2968	1,2-Dichlorobenzene	[600]	ND	ug/L	EPA 524.2	0.35	11/08/01	E96080
2969	1,4-Dichlorobenzene	[75]	ND	ug/L	EPA 524.2	0.28	11/08/01	E96080
2976	Vinyl chloride	[1]	ND	ug/L	EPA 524.2	0.33	11/08/01	E96080
2977	1,1-Dichloroethene	[7]	ND	ug/L	EPA 524.2	0.21	11/08/01	E96080
2979	trans-1,2-Dichloroethene	[100]	ND	ug/L	EPA 524.2	0.18	11/08/01	E96080
2980	1,2-Dichloroethane	[3]	ND	ug/L	EPA 524.2	0.45	11/08/01	E96080
2980	1,1,1-Trichloroethane	[200]	ND	ug/L	EPA 524.2	0.25	11/08/01	E96080
2982	Carbon tetrachloride	[3]	ND	ug/L	EPA 524.2	0.28	11/08/01	E96080
2983	1,2-Dichloropropane	[5]	ND	ug/L	EPA 524.2	0.23	11/08/01	E96080
2984	Trichloroethene	[3]	ND	ug/L	EPA 524.2	0.21	11/08/01	E96080
2985	1,1,2-Trichloroethane	[5]	ND	ug/L	EPA 524.2	0.23	11/08/01	E96080
2987	Tetrachloroethene	[3]	ND	ug/L	EPA 524.2	0.26	11/08/01	E96080
2989	Chlorobenzene	[100]	ND	ug/L	EPA 524.2	0.23	11/08/01	E96080
2990	Benzene	[1]	ND	ug/L	EPA 524.2	0.090	11/08/01	E96080
2991	Toluene	[1000]	ND	ug/L	EPA 524.2	0.18	11/08/01	E96080
2992	Ethylbenzene	[700]	ND	ug/L	EPA 524.2	0.19	11/08/01	E96080
2996	Styrene	[70]	ND	ug/L	EPA 524.2	0.24	11/08/01	E96080

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DISINFECTION BYPRODUCTS ANALYSES

62-550.310(3)

Client:	Florida Power & Light	Report Number/ Job ID	Potable Tri-Annual Samples
Sample Location:	Potable P.O.E. Grab	Disinfectant Residual (mg/L	
Sample Number:	2019680001	PWS ID	
Sampling Date:	8/25/04 15:00		
Date Received:	8/26/04 12:05		

Contam ID	Contam Name	MCL	Units	Analysis Result	Qualifier	Analytical Method	Lab MDL	Analysis Date	Analysis Time	Lab ID
2450	Monochloroacetic Acid	[N/A]	ug/L	5.3		EPA 552.1	0.88	9/01/04	7:26 PM	E96080
2451	Dichloroacetic Acid	[N/A]	ug/L	120	L	EPA 552.1	0.66	9/01/04	7:26 PM	E96080
2452	Trichloroacetic acid	[N/A]	ug/L	100	L	EPA 552.1	0.20	9/01/04	7:26 PM	E96080
2453	Monobromoacetic Acid	[N/A]	ug/L	0.28 U		EPA 552.1	0.28	9/01/04	7:26 PM	E96080
2454	Dibromoacetic Acid	[N/A]	ug/L	1.3		EPA 552.1	0.18	9/01/04	7:26 PM	E96080
2456	Total Haloacetic Acids (HAA5)	[60]	ug/L	230		EPA 552.1	0.18	9/01/04	7:26 PM	E96080
2941	Chloroform	[N/A]	ug/L	250	L	EPA 524.2	0.25	9/01/04	2:00 AM	E96080
2942	Bromoform	[N/A]	ug/L	0.41 U		EPA 524.2	0.41	9/01/04	2:00 AM	E96080
2943	Bromodichloromethane	[N/A]	ug/L	37		EPA 524.2	0.25	9/01/04	2:00 AM	E96080
2944	Dibromochloromethane	[N/A]	ug/L	3.9		EPA 524.2	0.30	9/01/04	2:00 AM	E96080
2950	Total Trihalomethanes	[80]	ug/L	290		EPA 524.2	0.50	9/01/04	2:00 AM	E96080

Golder Associates

SUBJECT	Aerator Required Size
Job No. 063-3495	Made by NCF
Ref. Calc 002	Checked SUM
Reviewed	Date 9/16/06
	Sheet 1 of 1

Martin Plant Operator (Stan McElroy) suggested the plant potable water aerator may not be adequate for the required duty, see DN-402 (attached) & Plant Potable Water System Manual

We have a multiple-tray aerator manufactured by DeLoach Industries

1) look at chloroform, based on Calc 1, assume 250 μg/L, flow = 50 gpm per Stan McElroy

Based on sample problem page 245 of AWWA's "Water Quality and Treatment":

convert 50 gpm to air volume, assuming 30:1 ratio as in sample problem

1 gal = 231 cu in = $\frac{231}{1728}$ cu ft = 0.1336 ft³/gal

50 * .1336 = 6.7 ft³/minute

6.7 ft³/min x 30 = 201 $\frac{cu.ft}{min}$

AMERICAN WATER WORKS ASSOCIATION

Water Quality and Treatment

A Handbook of Community Water Supplies

FOURTH EDITION

where c_i is the concentration of gas in the water at the influent to the tower, and c_e is the concentration of gas in the water at the exit to the tower.

Again care must be exercised so that the units are consistent. The log mean of the driving force is given by

$$\mathrm{DF}_{\ln} = \frac{\mathrm{DF}_e - \mathrm{DF}_i}{\ln(\mathrm{DF}_e/\mathrm{DF}_i)} \tag{5.30}$$

Example Problem 1 Chloroform at a concentration of 119 μg/L is to be reduced to 11.9 μg/L by an air stripping tower. What is the required height for the following conditions?

L	73 m³ water/(m² tower cross section)(hour (h))
G	2200 m³ air/(m² tower cross section)(h); (30:1 air-to-water volume ratio)
T	20°C = 293 K
H_D	2.55×10^{-5} atm L/mg (Table 5.1)
$K_L a$	30 h⁻¹ (given value)

Solution Assume $p_i = 0$ (that is, no chloroform exists in the air entering the tower) and calculate p_e by the material balance equation, Eq. (5.24).

Because the molecular weight of chloroform is 119, $C_i = 1 \times 10^{-3}$ mol/m³. Therefore,

$$L\,dc = G\,dp \qquad [\text{Eq. (5.24)}]$$

$$73(1 \times 10^{-3} - 1 \times 10^{-4}) = 2200(p_e - 0)$$

$$p_e = 2.99 \times 10^{-5}\ \frac{\text{mol gas}}{\text{m}^3\text{ air}}$$

Because 0.082T L of air are in each mole of air,

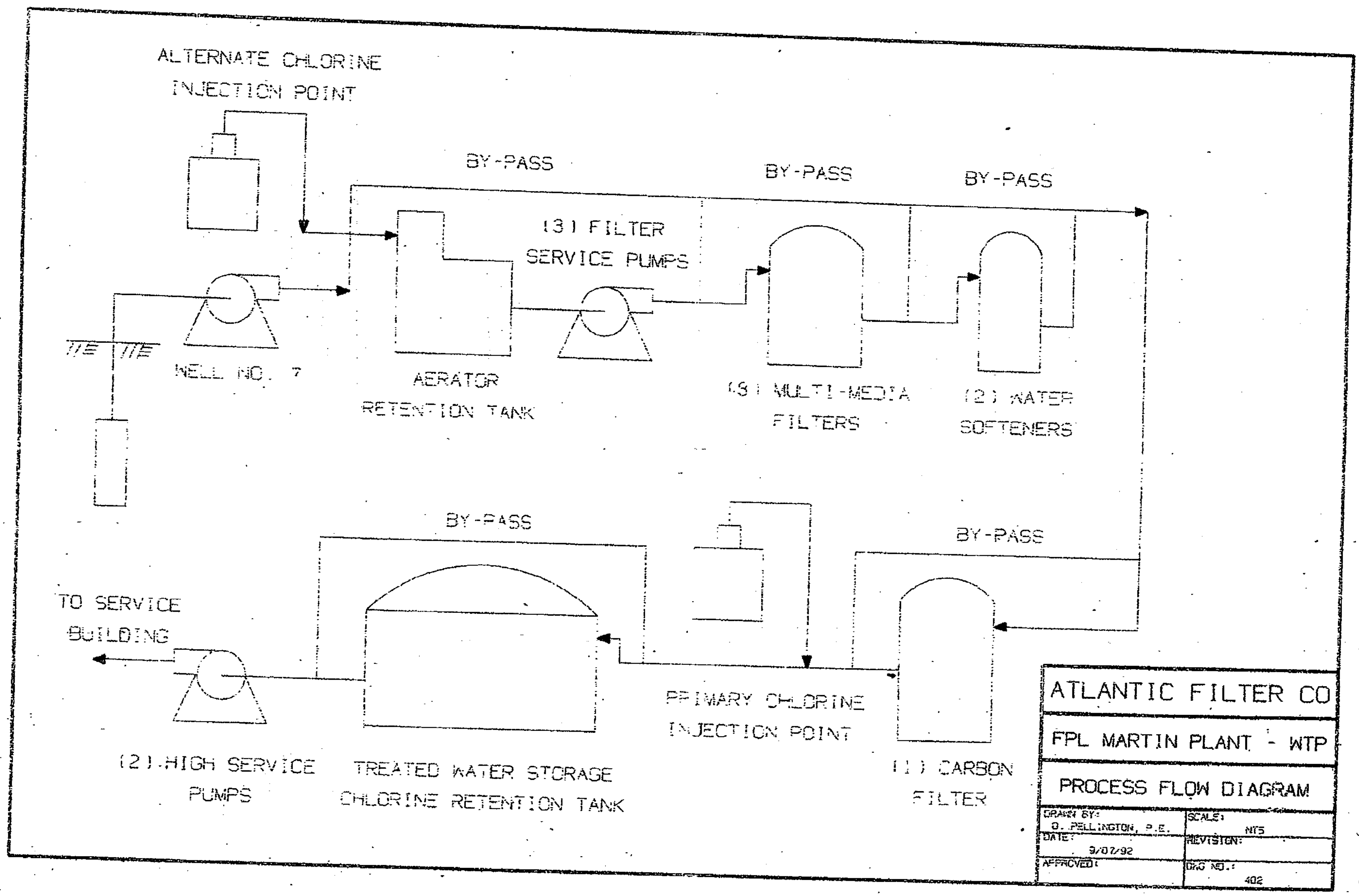
$$p_e = 2.99 \times 10^{-5}\ \frac{\text{mol gas}}{\text{m}^3\text{ air}}\ \frac{0.082(293) \times 10^{-3}\text{ m}^3\text{ air}}{\text{mol air}}$$

$$= 7.2 \times 10^{-7}\ \frac{\text{mol gas}}{\text{mol air}}$$

The driving forces are then calculated.

	Concentration in air p, mol gas/mol air	Concentration in water c, mg/L	$c_s = p/H_D$, mg/L	DF = $c - c_s$
Exit (top)	7.2×10^{-7}	0.119	0.0282	0.0908
Entrance (bottom)	0	0.0119	0	0.0119

The log mean of the driving force is found by Eq. (5.30)



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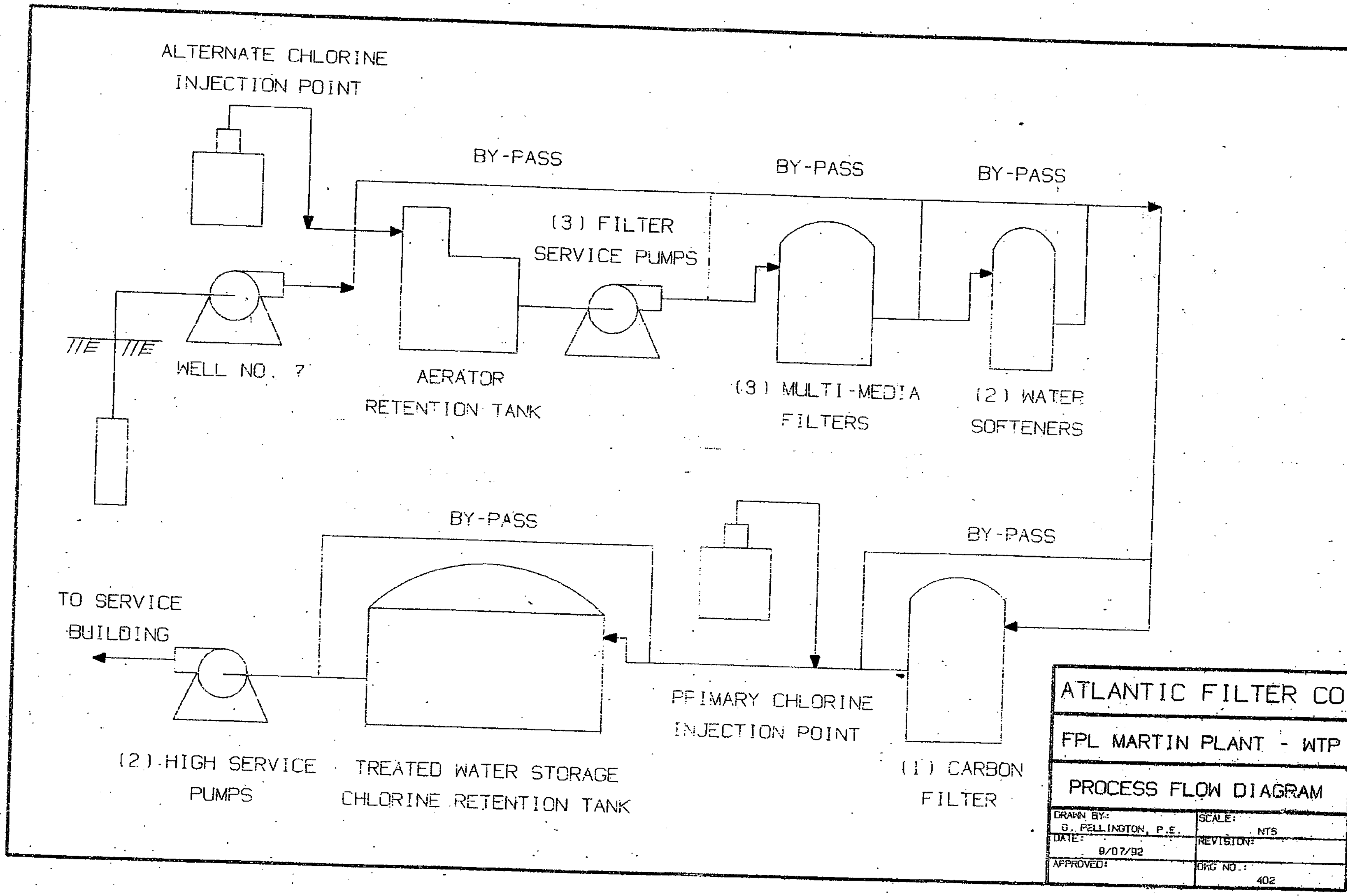
GOLDER ASSOCIATES, INC.
EXHIBIT RRL-3, PAGE 76 OF 107



DOCKET NO. 070007-EI
GOLDER ASSOCIATES, INC.
EXHIBIT RRL-3, PAGE 77 OF 107

Golder Associates

SUBJECT GAC Unit Size		
Job No. 063-5475 Ref. Calc 003	Made by NAF Checked SUM Reviewed MD	Date 8/16/06 Sheet of

The granular activated carbon (GAC) unit (See DN-402 attached to Calc 2) contains 40 cu ft of media, as reported by the Martin Plant Operator (Stan McElvay) during the site visit, and system flow rate is 50 gpm when the well pump is on.

Calculate the Empty Bed Contact Time

$$(EBCT) = \frac{\text{Bed Volume}}{\text{Flow Rate}} = \frac{40\ ft^3 \times \frac{1\ gal}{0.1336\ ft^3}}{50\ gal/min}$$

$$= 6 \text{ minutes}$$

Per Reference 2 (AWWA Water Treatment Plant Design), EBCT should be between 5 & 25 minutes

From Plant Data Book, Section 10, page 11, its actually $39\ ft^3$

$\rightarrow$ EBCT = 5.8 minutes

DOCKET NO. 070007-EI
GOLDER ASSOCIATES, INC.
EXHIBIT RRL-3, PAGE 79 OF 107

AMERICAN WATER WORKS ASSOCIATION
AMERICAN SOCIETY OF CIVIL ENGINEERS

Water Treatment Plant Design

THIRD EDITION

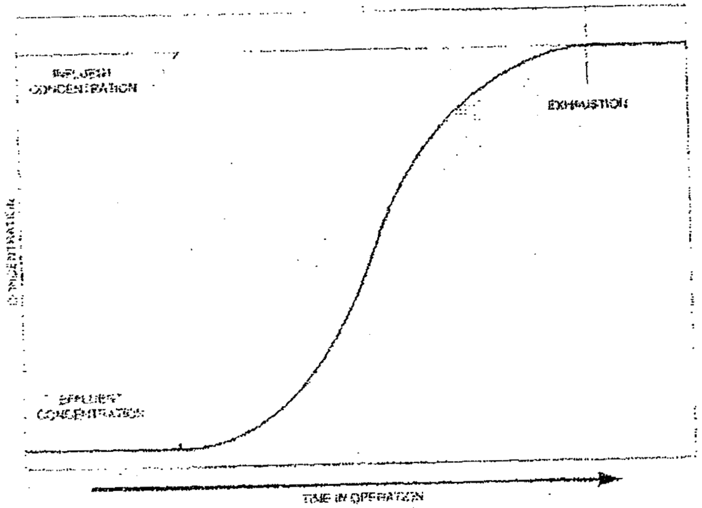


FIGURE 14.3 Breakthrough pattern for GAC filter.

the type and depth of carbon and specific solute characteristics. Breakthrough curves are important to the designer because they define the relationship between the physical and chemical parameters of the carbon system (e.g., flow rate, bed size, carbon exhaustion rate), the determination of the number of beds or columns, their arrangement (either series or parallel), and treatment plant effluent requirements.

Empty Bed Contact Time. Empty bed contact time (EBCT) is calculated as the volume of the empty bed (occupied by the GAC) divided by the volumetric flow rate of water through the carbon. Alternatively, EBCT can be defined as the depth of GAC divided by the linear velocity of water flowing through the carbon bed. It should be noted that EBCT is a false-residence time.

EBCT is used instead of detention time because of the ease of calculation. An actual detention time would have to account for the porosity of the bed, a variable that changes with carbon size and type. EBCT can be varied by changing the bed depth at constant flow or by changing flow with constant bed depth. Together, the design EBCT and the design flow rate define the amount of carbon to be contained in the adsorption units.

Longer EBCTs can delay breakthrough (to a point) and improve carbon usage rate; shorter EBCTs can expedite breakthrough. Thus the time of GAC operation between replacement or regeneration depends on the EBCT. For most water treatment applications, EBCTs range between 5 and 25 minutes. In addition, a factor having a greater influence on operating costs than EBCT is volume throughput, which is the number of bed volumes of water processed before the breakthrough concentration is reached.

Adsorber Volume and Bed Depth. After the EBCT has been determined, carbon depth can be selected. The adsorber design volume depends on bed volume and the amount of freeboard (excess vessel capacity beyond design operating levels). Freeboard can range up

to about 50% for fixed and expanded bed systems. If bed expansion is unnecessary, a freeboard of 20% to 30% may be adequate to allow for proper bed expansion during backwashing.

No freeboard is needed for upflow pulsed beds. An economic evaluation is usually made of capital and operating costs to compare carbon columns of various depths.

Hydraulic Loading Rate. The surface loading rate for GAC filters is related to the design flow of a particular treatment plant. Surface loading rates are defined in the same manner as conventional granular media filters. The surface loading rate is the rate of a volume of water passing through a given area of GAC filter bed, usually expressed as cubic meters per square vector (m^3/m^2) or gallons per minute per square foot (gpm/ft^2). Surface loading rates for GAC filters range from 2 to 10 gpm/ft^2 (5 to 24 m/h), although rates of 2 to 6 gpm/ft^2 (5 to 15 m/h) are more commonly used as design criteria.

Surface loading should be kept large for compounds, where the mass transfer rate is controlled by the rate of transfer of the chemical from the bulk liquid to the interior pores of the GAC. Typically this is the case for highly adsorbable compounds (e.g., many SOCs). When mass transfer is controlled by the rate of adsorption (and transport) within the GAC particle, surface loading is not important. This is the case with most less-adsorbable compounds. Figure 14.4 illustrates the relationship between hydraulic loading and pressure drop for several brands of GAC.

Backwashing. A GAC filter bed is backwashed using the same general procedures typically used for backwashing conventional granular gravity filters. If GAC is installed as a sand filter replacement, a redesign of the backwash supply system, including the rate of flow control and washwater troughs height, is often necessary. This redesign is necessary because of the difference in particle density between GAC and sand—about 1.4 g/cm^3 and 2.65 g/cm^3, respectively. If GAC is used as a simple replacement for anthracite coal as a filter medium, the backwash system may be adequate because particle densities are nearly identical.

GAC particle size distribution and wetted density vary among different carbon brands and even among different deliveries of the same carbon. Appropriate backwash rates can be obtained from the manufacturer for each type of carbon (Figure 14.5). Backwash rates must be adjusted to account for specific media characteristics and for changes in backwash water temperature (Figure 14.6). Installing a surface wash or air scour system to assist with filter cleaning may be necessary to control mudball formation.

A good conservative design should allow for 75% to 100% expansion of light GAC media, but 50% is generally considered to be adequate. The design should provide for sufficient freeboard to reduce media losses during the backwashing cycle.

Carbon Usage Rate. The carbon usage rate (CUR) determines the rate at which carbon will be exhausted and how often the carbon must be replaced. The CUR essentially determines the size of the entire regeneration system. The CUR for GAC systems removing organic compounds may be determined using physical models or adsorption isotherm models. A pilot-scale test is often used to evaluate the complexity of multiple chemical interactions. A quicker and more economical method for evaluating GAC column performance is the rapid small-scale column test (RSSCT). Small systems can be designed to best simulate the performance of a full-scale system using dimensional analysis. Dimensionless parameters for the full-scale system and the small system are designed to be equal.

Carbon treatment effectiveness improves as contact time increases. The percentage of total carbon in a bed that is exhausted at breakthrough is greater in a deeper bed than in a shallower bed. At a point beyond the optimum bed depth, the additional adsorber volume provided acts primarily as a storage capacity for spent carbon. The actual selection of bed depth and corresponding adsorber volume also depends on

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SECTION 10 - WATER TREATMENT SYSTEM

1. GENERAL SYSTEM DESCRIPTION

Prechlorinated well water from the raw water storage tank is pumped through the pretreatment system where it is lime softened and filtered. The pretreating equipment consists of a coagulator, clearwell, two treated water transfer pumps and four pressure sand filters. The treated water effluent from the sand filters is routed to the 500,000-gallon treated water storage tank which supplies the treated water requirements of the demineralizer units and miscellaneous plant services. Water from an on-site well serves the potable water system, which consists of a carbon filter, chlorinator, storage tank and two service pumps. The demineralizer system is of the two parallel train design with each train consisting of a strong acid cation unit, a weak base anion unit, a strong base anion unit and a polishing mixed bed unit. Most of the controls and instrumentation are mounted in a control panel conveniently located in the water treating area.

2. PRETREATMENT SYSTEM

The 885 gpm capacity pretreatment system includes prechlorination, cold lime softening, coagulation and filtration of raw well water.

Two coagulator feed pumps, taking suction from the raw water storage tank, deliver the prechlorinated well water through a flow metering device, a pneumatically actuated modulating control valve, and to the coagulator.

The coagulator inlet flow control valve is positioned based on system demand from the clearwell. This is accomplished by positioning the inlet control valve so that the inlet flow rate to the coagulator matches system demand which is derived from the clearwell level. The minimum clearwell level is analogous to maximum demand. At this point, the inlet control valve to the coagulator should be wide open.

The system is automatically shut down at maximum clearwell level which corresponds to essentially zero inlet flow rate. At this point, the inlet control valve closes, the coagulator feed pumps are stopped, and the chemical feeder decanting mechanisms are lifted.

As the system demand increases to approximately 25 percent of the design flow rate, with a corresponding drop in the clearwell level, the inlet control valve opens, the coagulator feed pumps start, and the decanting mechanisms in the chemical feed tanks are lowered.

The coagulator is equipped with an automatic type, timer controlled blowdown system to permit effective removal of sludge. pH monitors are provided for the coagulator effluent, before and after acid addition.

Alum and lime are fed to the coagulator for the purpose of softening and coagulating the raw water supply. Both chemicals are gravity fed through a swing drawoff pipe in each tank which is positioned by a decanting drive. The chemical feed rates are proportional to the service flow. The alum and lime tanks are provided with mechanical agitators and are sized to hold a charge of chemical sufficient for 36 hours of operation at design flow. An additional chemical feed line is provided for the coagulator to permit future injection of coagulant aid, if required.

A bulk lime handling system is provided in order to facilitate and automate the storage, slaking, transfer and conversion of quick lime into lime slurry. Quick pebble lime from the delivery truck is pneumatically conveyed to the top of the lime silo for storage and then gravimetrically fed to the slaker through the discharge hopper. The slaked lime, after removal of grit, flows to the slurry suction tank. A transfer pump, equipped with automatic flushing and recirculation, is provided to transport lime slurry from the suction tank to the holding tank. Lime slurry transfer is automatically initiated based on level in the holding tank. A manual outlet valve is provided for the holding tank to allow gravity transfer of lime slurry into the lime feed tank. Treated water is to be used for the slaking and dilution of lime.

Acid solution is fed to the coagulator effluent in order to reduce the pH of the softened water, thereby, minimizing the possibility of scale formation in the filter beds and related equipment. The acid feed pump is of the positive displacement diaphragm type, equipped with pneumatic stroke adjustor. The signal from the pH meter, which monitors the clearwell influent, regulates the acid feed rate. The capacity of the acid solution feed tank is adequate for 36 hours of operation at design flow.

The coagulated, softened and pH adjusted effluent from the coagulator flows by gravity to a 30,000-gallon clearwell. Two, full capacity treated water transfer pumps transport the water from the clearwell, through four parallel sand filters and to the treated water storage tank. The sand filters are designed to operate at a normal rate of 222 gpm and a maximum rate of 295 gpm while one of the filters is being backwashed or rinsed. Each filter unit is provided with a set of manual valves to permit isolation and manual backwashing, rinsing and return to service. The need for filter backwashing is indicated by high pressure drop and reduced flow through any filter units. Water for filter backwashing is taken from the raw water storage tank. The treated water storage tank level is controlled by an inlet flow control valve.

3. POTABLE WATER TREATMENT SYSTEM

Approximately 50 gpm of well water is routed through a carbon filter. Then, the carbon filter effluent is chlorinated prior to storage. The chlorine feed rate is proportional to potable water flow which, in turn, is regulated by the level controller in the potable water storage tank. The carbon filter is also backwashed based on increase in pressure drop and reduction in service flow. Manual valves for isolation, backwash, rinse and return to service are also provided. Potable water is used for backwashing the carbon filter.

4. DEMINERALIZER SYSTEM

Two 700 gpm capacity demineralizer feed pumps provide the treated water requirements of the ion exchangers. The demineralizer system includes two parallel trains of ion exchange units with each train consisting of a strong acid cation, weak base anion, strong base anion and a mixed bed polisher. Each primary train is designed for 350 gpm; whereas, each mixed bed polisher is nominally rated at 700 gpm capacity. The primary cation units have provisions for future addition of ion exchange resins. The net volumetric throughput between regenerations is 378,000 gallons per primary train and 7,700,000 gallons per mixed bed polisher. Acid and caustic regeneration systems are provided in order to restore the ion exchangeability of the demineralizer units upon exhaustion. Sulfite solution is fed into the demineralizer influent line in order to protect the resins from the oxidative effect of residual chlorine. The treated water influent to the demineralizer units is continuously monitored by a chlorine analyzer. The cleaning of organically fouled ion exchangers is accomplished by the use of the brine recirculation system.

Two 100% capacity, vertical pumps mounted on top of the 10,000-gallon acid storage tank, together with strong acid flow controller, teflon lined mixing tee, dilution water flow controllers, conductivity indicators and control valves, are provided to regenerate the primary cation and mixed bed cation resin beds. The acid solution from the dilution station is also intended for filling up the acid feed tank which serves the coagulator effluent.

Two 100% capacity, vertical pumps mounted on top of the 10,000-gallon caustic storage tank, including strong caustic and dilution water flow controllers, saran lined mixing tee, conductivity indicator, dilution water heat exchanger, thermostatic controller, temperature indicator with alarm switch, and control valves, are all provided to serve the primary weak base and strong base anion, and mixed bed anion resin beds. An air blower is also furnished to properly mix the freshly regenerated and stratified resin layers in the mixed bed unit. The temperature of the dilute caustic solution is to be automatically maintained at 120°F by controlling the steam supply to the dilution water heat exchanger. The caustic storage tank is provided with immersion type electrical heaters in order to maintain a minimum caustic temperature of 70°F.

The brine recirculation system is designed for manual operation with the exception of the brine heater. This system consists of rubber lined brine mixing tank and brine measuring tank, brine solution heat exchanger, thermostatic controller, temperature indicator with alarm switch, pressure gauges, valves and a brine recirculation pump. The dilution water source is demineralized water. The brine recirculation system serves all ion exchangers except the primary cation units. Termination of brine recirculation is determined by visual observation of the brine solution. A manual "dump" valve is provided in the brine return line to the measuring tank, and this allows draining of highly contaminated brine solution.

During normal service conditions, only one demineralizer feed pump is expected to be operating. The influent treated water passes through the cation units where ions of calcium, magnesium and sodium are trapped in and hydrogen ion released from the resin media. The acidic effluent then flows through the weak base anion units where sulfates and chlorides are removed and exchanged for hydroxyl ions. The partially demineralized water then flows through the strong base anion units in order to remove carbon dioxide and silica. Cation and anion leakages, consisting primarily of sodium and silica ions, are removed in the polishing mixed bed unit(s).

After a certain service period, depending on the flow rate and quality of treated water supply, the demineralizer units reach their exhausted state. This service period is determined by volumetric end of run (gallons) or by high conductivity (umhos/cm) in the primary anions and mixed bed units. At the operator's option, the exhausted primary train is regenerated by pushbutton initiation; all succeeding steps are fully automatic. The regeneration system controls are designed to allow regeneration of the cation unit prior to both primary anion units. Regeneration of the primary units essentially includes backwashing, settling, chemical regenerant introduction, displacement and rinse. Another step is included in the anion regeneration procedure, i.e. conductivity check. The regeneration of the primary anion units is accomplished by passing fresh caustic solution first through the strong base and then routing the spent caustic to the weak base unit. The primary cation is regenerated using treated water; decationized water is used for primary anion regeneration.

Regeneration of the mixed bed units is performed in a similar manner except that acid regeneration of the lower and relatively heavier cation resin layer is done countercurrently and prior to caustic regeneration of the upper anion layer. A mid-bed collector serves as a drainage for the chemical waste and the rinse waste. The air blower is turned on after chemical regeneration of the mixed bed. The pressurized air uplifts and mixes the freshly regenerated anion and cation resin layers. Fast rinse and conductivity check are the two last steps in the mixed bed regeneration. Backwash and rinse water is taken from the strong base anion effluent.

Return to service of a newly regenerated primary train or mixed bed polisher is also a pushbutton initiated operation.

All recorders, indicators, annunciators, controls and instrumentation are mounted on the totally enclosed NEMA Class 3, walk-in type control panel. The panel is also provided with air conditioning equipment and glass windows. Individual solenoid valve cabinets are also provided for each skid-mounted demineralizer unit.

5. EQUIPMENT DATA

5.1 Raw Water Chlorinator

Manufacturer	Fisher & Porter
Quantity	One

Type	F & P Model 70C3430 gas chlorinator, vacuum type, with automatic proportioning control, using 3-15 psig square root signal from raw water flowmeter.
Capacity	75 lbs. Cl_2/day
Accessories	Internal heater, weighing scale, gas mask, ejector, diffuser, gauges, valves and connectors.
Use	Chlorinate and condition incoming well water to the raw water storage tank.

5.2 Coagulator

Manufacturer	Hungerford & Terry, Inc.
Quantity	One
Type	Circular steel shell and bottom with internal coating of vinyl copolymer, sludge recirculating type with full bottom scraper.
Capacity	885 gpm.
Dimension	37' - 0" dia. x 16' - 0" straight shell.
Rinse Rate	1.0 gpm/ft^2.
Retention Time	90 minutes (minimum) at design rate.
Blowdown System	Inlet meter totalizer and automatically initiated time span blowdown, which will be pneumatically operated.
Recirculation Agitator & Drive	Two Proquip Model No. 1ZEX50 top entering, right angle, turbine trip agitators with 1-1/2 hp motor; one Winsmith speed reducer, Model No. 15CVD.
Blowdown Rate & Frequency	150 gpm for 3 minutes every 15-minute cycle.

Bottom Scraper & Drive	1/4 hp, Reeves "Motodrive," rated for 115 V, single phase, 60 Hz.
Accessories	One set of pH measuring equipment for monitoring of effluent pH.
Sample Connections	Sample connections, piping and valves, sink mounted on coagulator shell.
Use	Softening and coagulation of raw well water.

5.3 <u>Lime Feed System</u>

Manufacturer	Hungerford & Terry, Inc.
Quantity	One
Type	Vertical, cylindrical steel tank with bottom dished head, top cover and top loading door for gravity feeding into the coagulator.
Capacity	5000 gallons of 10% by weight lime slurry.
Dimension	11' - 0" dia. x 7' - 0" straight side.
Mixer	
Type	Lightnin Model 71Q2 with type 316 stainless steel shaft and impellers.
Motor Rating & Enclosure	2 hp, 460 V, 3 phase, 60 Hz, TEFC.
Accessories	1/6 hp, Graham Model N27MW60 gear motor for swing pipe drive, 115 V, single phase, 60 Hz, reversible 0-9 rpm output; dust evacuator.
Use	Softening of raw well water.

5.4 <u>Alum Feed System</u>

Manufacturer	Hungerford & Terry, Inc.
Quantity	One

Type	Vertical, cylindrical, type 316 stainless steel tank with bottom dished head, top cover and top loading door for gravity feeding into the coagulator.
Capacity	500 gallons of 5% by weight alum solution.
Dimension	4' - 6" dia. x 4' - 0" straight side.
Mixer	
Type	Lightnin Model NLDG-33 with type 316 stainless steel shaft and impellers.
Motor Rating & Enclosure	1/3 hp, 115 V, single phase, 60 Hz, TEFC
Accessories	1/6 hp, Graham Model N27MW60 gear motor for swing pipe drive, 115 V, single phase, 60 Hz, reversible 0-9 rpm output; dissolving basket.
Use	Coagulation of raw well water.

5.5 Acid Feed System

Manufacturer	Hungerford & Terry, Inc.
Quantity	One
Type	Vertical, cylindrical, rubber lined steel tank with flat bottom and top cover plate.
Capacity	500 gallons of 10% by weight H_2SO_4 solution.
Dimension	4' - 6" dia. x 5' - 0" high
Feed Pump	
Type	Milton Roy Model AFR-125A-117, diaphragm type metering pump with TFE diaphragm and pneumatic stroke adjustor.
Motor Rating & Enclosure	1/4 hp, 115 V, 1 phase, 60 Hz. TESXT.

Feed Rate	5 gal/hr. of 10% acid solution
Accessories	One set of pH measuring equipment for automatic control of acid feed pump, level switch for automatic filling of tank.
Use	Prevention of carbonate post-precipitation in the clearwell, piping and sand filters.

5.6 Clearwell

Manufacturer	Hungerford & Terry, Inc.
Quantity	One
Type	Circular, steel shell, top conical roof, flat bottom with internal coating of vinyl copolymer.
Capacity	30,000 gallons
Dimension	18' - 6" dia. x 16' - 0" high
Accessories	Level indicator, horizontal internal baffles.
Use	Surge tank for softened and coagulated water.

5.7 Treated Water Transfer Pumps

Manufacturer	Worthington
Quantity	Two
Type	Horizontal, centrifugal type, Worthington Model D1011 with bronze impeller and cast iron casing.
Capacity and Head	885 gpm at 115 ft. tdh
Speed	1750 rpm
Motor Rating & Enclosure	50 hp, 460 V, 3 phase, 60 Hz, TEFC.

Accessories	Pressure indication, isolation and check valves, recycle valve
Use	Supply coagulated and softened water to the sand filter units.

5.8 Pressure Sand Filters

Manufacturer	Hungerford & Terry, Inc.
Quantity	Four
Type	Skid-mounted, manual pressure filters designed for parallel operation.
Design Pressure	75 psig ASME Code
Design Flow	295 gpm (maximum rating per unit)
Dimension	9' - 0" dia. x 5' - 0" straight shell
Filter Media & Support Bed	189 ft^3 of filter sand and 84 ft^3 of graded gravel
Backwash Rate & Duration	950 gpm per unit for 10 minutes
Rinse Rate & Duration	200 gpm per unit for 5 minutes
Accessories	Individual flow meters and differential pressure gauges.
Use	Removal of suspended solids from coagulated and softened water.

5.9 Carbon Filter

Manufacturer	Hungerford & Terry, Inc.
Quantity	One
Type	Skid-mounted, manual pressure filter.
Design Pressure	75 psig ASME Code

Design Flow	50 gpm
Dimension	4' - 6" dia. x 5' - 0" straight shell
Vessel Lining	3/16" thick rubber
Filter Media	39 ft^3 of activated carbon
Backwash Rate & Duration	100 gpm for 10 minutes
Rinse Rate & Duration	50 gpm for 5 minutes
Accessories	Inlet flow meter and differential pressure gauge.
Use	Removal of trace color and odor.

5.10 Potable Water Chlorinator

Manufacturer	Fischer & Porter
Quantity	One
Type	F & P Model 70C3430 gas chlorinator with automatic proportioning control using 3-15 psig square root signal from carbon filter effluent flowmeter.
Capacity	3 lbs. Cl_2/day
Accessories	Internal heater, weighing scale.
Use	Chlorinate carbon filter effluent in order to meet potable water requirements.

5.11 Sulfite Feed System

Manufacturer	Hungerford & Terry, Inc.
Quantity	One
Type	Vertical, cylindrical, type 304 stainless steel tank with flat bottom and hinged cover.

Capacity	100 gallons of 5% by weight sodium sulfite solution.
Feed Pump	
Type	Milton Roy Model FR-111A-117, diaphragm type metering pump with manual stroke adjustor.
Motor Rating & Enclosure	1/4 hp, 115 V, 1 phase, 60 Hz, TESXT.
Feed Rate	2.8 gal/hr. of 5% sulfite solution.
Mixer	
Type	Milton Roy, with type 316 stainless steel shaft and impellers.
Motor Rating & Enclosure	1/4 hp, 115 V, 1 phase, 60 Hz, TESXT.
Accessories	Polyethylene floating cover, type 316 stainless steel dissolving basket, low level pump cut-off switch, external relief valve.
Use	React with residual chlorine present in treated water supply.

5.12 Demineralizer Feed Pumps

Manufacturer	Aurora
Quantity	Two
Type	Horizontal, centrifugal type, Aurora Model 411 with bronze impeller and cast iron casing.
Capacity and Head	700 gpm at 290 ft tdh.
Speed	3500 rpm
Motor Rating & Enclosure	75 hp, 460 V, 3 phase, 60 Hz, TEFC.

Accessories	Pressure regulating valves, pressure indication, relief valve, isolation and check valves.
Use	Supply treated water to the demineralizer units for removal of dissolved solids.

5.13 <u>Cation Exchangers</u>

Manufacturer	Hungerford & Terry, Inc.
Quantity	Two
Type	Skid-mounted, automatic strong acid cation units designed for parallel operation.
Design Pressure	150 psig ASME Code
Design Flow	350 gpm per unit
Dimension	7' - 6" dia. x 8' - 8" straight shell
Vessel Lining	3/16" thick rubber
Resin Volume	184 ft^3 of strongly acidic cation resin, Rohm & Haas IR-120
Regeneration Level	5.0 lbs. of 66° Be H_2SO_4/ft^3 resin
Service Run Between Regeneration	418,000 gallons per unit
Accessories	Inlet flow meters, differential conductivity meters, sight windows, resin traps, inlet chlorine analyzer, solenoid valve cabinets.
Use	Removal of cations such as calcium, magnesium and sodium from treated water supply.

5.14 Weak Base Anion Exchangers

Manufacturer	Hungerford & Terry, Inc.
Quantity	Two
Type	Skid-mounted, automatic weak base anion units designed for parallel operation.
Design Pressure	150 psig ASME Code
Design Flow	350 gpm per unit
Dimension	7' - 6" dia. x 6' - 2" straight shell
Vessel Lining	3/16" thick rubber
Resin Volume	132 ft^3 of weakly basic anion resin, Rohm & Haas IRA-93
Regeneration Level	Spent caustic from strong base anion unit
Service Run Between Regeneration	398,000 gallons per unit
Accessories	Conductivity meters, sight windows, solenoid valve cabinets.
Use	Removal of strongly ionized anions such as sulfate and chloride; entrapment of certain organic compounds.

5.15 Strong Base Anion Exchangers

Manufacturer	Hungerford & Terry, Inc.
Quantity	Two
Type	Skid mounted, automatic strong base anion units designed for parallel operation.
Design Pressure	150 psig ASME Code.

Design Flow	350 gpm per unit
Dimension	7'-6" dia. x 6'-2" straight shell
Vessel Lining	3/16" thick rubber
Resin Volume	132 ft^3 of strongly basic anion resin, Rohm & Haas IRA-402
Regeneration Level	5.0 lbs. of 100% $NaOH/ft^3$ resin
Service Run Between Regeneration	378,000 gallons per unit
Accessories	Effluent and in-bed probe conductivity meters, sight windows, resin traps, solenoid valve cabinets.
Use	Removal of weakly ionized anions such as silica and carbon dioxide.

5.16 Mixed Bed Exchangers

Manufacturer	Hungerford & Terry, Inc.
Quantity	Two
Type	Skid-mounted, automatic mixed bed units with one unit serving as a spare.
Design Pressure	150 psig ASME Code
Design Flow	700 gpm per unit
Dimension	7' - 6" dia. x 6' - 0" straight shell
Vessel Lining	3/16" thick rubber
Resin Volume	83 ft^3 of Dow's HGR and 66 ft^3 of Dow's SBR-P
Regeneration Levels	6 lbs. of 66° Be H_2SO_4/ft^3 of cation resin and 6 lbs. of 100% $NaOH/ft^3$ of anion resin
Service Run Between Regeneration	7,700,000 gallons per unit

Accessories	Inlet flow meters, effluent and in-bed probe conductivity meters, sight windows, resin traps, solenoid valve cabinets
Use	Removal of cation and anion leakages, primarily sodium and silica, from the primary units effluent.

5.17 <u>Air Blower</u>

Manufacturer	Roots
Quantity	One
Type	Rotary, positive displacement type, Model 76 RAI-V with cast iron impeller, head-plate and case, steel shafts.
Inlet Capacity	400 cfm at 10 psig
Speed	1280 rpm
Motor Rating & Enclosure	25 hp, 460 V, 3 phase, 60 Hz, TEFC
Accessories	Filter-silencer, pressure relief valve, V-belt drive, flowmeter.
Use	Resin mixing in the mixed bed unit.

5.18 <u>Caustic Dilution Water Heat Exchanger</u>

Manufacturer	Bell & Gosset
Quantity	One
Type	Horizontal shell and U-tube heat exchanger, Model SU-66-21 of type 316 stainless steel construction on tube side.
Design Pressure	150 psig ASME Code
Heating Capacity	Heat 35 gpm of water from 55° to 120°F

Steam Requirements	1175 lbs./hr. of 25 psig saturated steam
Heating Surface Area	22.1 ft^2
Accessories	Pressure relief valve, steam control valve, steam traps, strainers.
Use	Preheat caustic dilution water to achieve better silica removal during anion regeneration.

5.19 Acid Regeneration Pumps

Manufacturer	Taber
Quantity	Two
Type	Vertical, submerged centrifugal type, Taber Model 1292 with Alloy 20 impeller and casing.
Capacity and Head	3 gpm at 115 ft. tdh
Speed	1750 rpm
Motor Rating & Enclosure	7-1/2 hp, 460 V, 3 phase, 60 Hz, TEFC.
Accessories	Pressure indication, isolation and check valves, recycle valve, strainer
Use	Supply 66° Be H_2SO_4 to the acid regeneration system and to the acid day tank in the pretreatment system.

5.20 Caustic Regeneration Pumps

Manufacturer	Taber
Quantity	Two
Type	Vertical, submerged centrifugal type, Taber Model 1292 with type 316 stainless steel impeller and casing.

Capacity and Head	2 gpm at 115 ft. tdh
Speed	1750 rpm
Motor Rating & Enclosure	5 hp, 460 V, 3 phase, 60 Hz, TEFC
Accessories	Pressure indication, isolation and check valves, recycle valve, strainer.
Use	Supply 50% NaOH to the caustic regeneration system.

5.21 Acid Storage Tank

Manufacturer	Hungerford & Terry, Inc.
Quantity	One
Type	Horizontal, 25 psig design pressure, ASME code steel tank with ASME F & D heads
Coating	Interior coated with 5 to 6 mils of Plasite No. 3066
Dimension	10' - 0" dia. x 16' - 0" straight shell
Capacity	10,000 gallons
Accessories	Saddle supports, ladders and platforms.
Use	Storage for 66° Be H_2SO_4.

5.22 Caustic Storage Tank

Manufacturer	Hungerford & Terry, Inc.
Quantity	One
Type	Horizontal, 25 psig design pressure, ASME code steel tank with ASME F & D heads
Coating	Interior coated with 8 to 10 mils of Plasite No. 7133.

Dimension	10' - 0" dia. x 16' - 0" straight shell
Capacity	10,000 gallons
Accessories	Saddle supports, ladders and platforms
Use	Storage for 50% NaOH.

5.23 Brine Mixing Tank

Manufacturer	Hungerford & Terry, Inc.
Quantity	One
Type	Vertical, cylindrical steel tank with flat bottom and cover plate.
Lining	3/16" thick rubber for interior and 6 mils epoxy for exterior surfaces.
Dimension	5' - 6" dia. x 4' - 0" high
Accessories	Strainers
Use	Batching and dissolving tank for brine

5.24 Brine Measuring Tank

Manufacturer	Hungerford & Terry, Inc.
Quantity	One
Type	Vertical, cylindrical steel tank with bottom dished head and cover plate.
Lining	3/16" thick rubber for interior and 6 mils epoxy for exterior surfaces
Dimension	9' - 0" dia. x 11' - 0" straight side
Accessories	Level gauge, vent
Use	Surge tank during brine recirculation

5.25 Brine Solution Heat Exchanger

Manufacturer	Bell & Gossett
Quantity	One
Type	Horizontal shell and U-tube heat exchanger, Model SU-66, of type 316 stainless steel construction on tube side.
Design Pressure	150 psig ASME Code
Heating Capacity	Heat 35 gpm of 26% saturated brine solution from 55° to 120°F.
Steam Requirements	1175 lbs./hr. of 25 psig saturated steam
Heating Surface Area	22.1 ft^2
Accessories	Pressure relief valve, steam control valve, steam traps, strainers
Use	Preheat and maintain the temperature of recirculating brine solution

5.26 Brine Recirculation Pump

Manufacturer	LaBour
Quantity	One
Type	Horizontal, centrifugal type, LaBour Model LV with Alloy 20 impeller and casing.
Capacity and Head	35 gpm at 115 ft. tdh.
Speed	3500 rpm
Motor Rating & Enclosure	5 hp, 460 V, 3 phase, 60 Hz, TEFC.
Accessories	Pressure and flow indication, isolation and check valves, strainer, recycle valve, flush valve.

Use	Supply brine solution to the anion resin beds.

5.27 Control Panel

Manufacturer	Hungerford & Terry, Inc.
Quantity	One
Type	NEMA 3 construction, double-tunnel walk-through type, with sloping roof and removable sun canopy
Dimension	16' - 0" long x 9' - 0" deep x 8' - 7-1/2" high
Accessories	Air conditioning equipment, recorders, indicators, annunciators and other instrumentation and controls
Use	Serves as a central operating cubicle for monitoring operations and abnormalities in the water treatment system.

5.28 Bulk Lime Handling System

Manufacturer	Hungerford & Terry, Inc.
Quantity	One
Type	Bulk lime handling system consisting of a lime storage silo, a feeder and slaker, a slurry transfer pump, a slurry holding tank, and a control panel.

Lime Storage Silo

Type	Bolted steel construction with bake-on epoxy coating, including bin unloader, truck load line assembly, guardrails, access ladder with cage, high and low level indicators, discharge hopper, vacuum pressure valve, bag filter assembly, a 6" rotary valve with 1/2 hp motor and drive, shear protector and manual slide gate, as supplied by Butler Manufacturing Co.

Capacity	40 tons
Dimension	12' - 0" dia. x 32' - 0" high
Accessories	One Wallace & Tiernan Series A-758 lime slaking system complete with gravimetric feeder and stop-start controls; and one Hungerford & Terry control panel with controls and contacts for starting, stopping and controlling the system.

<u>Lime Slurry Transfer Pump</u>

Type	LaBour type DZT, size 14 2" x 1-1/2" horizontal centrifugal pump, with cast iron casing and type 316 stainless steel open impeller.
Capacity	10 gpm at 75 ft. tdh.
Speed	1800 rpm
Motor Rating & Enclosure	3 hp, 460 V, 3 phase, 60 Hz, TEFC
Accessories	Isolation valves for suction and discharge, slurry pump suction tank (36" dia. x 36" high)

<u>Slurry Holding Tank</u>

Type	Vertical, cylindrical tank of carbon steel construction with top cover and access door, round bottom, and structural steel support.
Dimension	11' - 0" dia. x 4' - 0" straight shell
Accessories	Two Lightnin Model NLDG-200 mixers with 2 hp motors; level controller with type 316 stainless steel probes; control and manual valves.
Use	Storage, gravimetric feeding, slaking and transfer of lime slurry into the holding tank.

DESCRIPTION	Manufacturer	Ingersoll-Rand Company
	Size and Type	5" x 9" SB
	Tag Number(s)	M-107.1.5
	Serial Number(s)	
	RPM/Number of Stages	1750/Single Stage
	Design Efficiency- %/BHP/WR^2	72/9.9/100
	Shut Off Head-FT.	54
	Max. BHP Des Imp.	9.9
DESIGN CONDITIONS	Liquid Pumped	Raw Water
	Pumping Temperature - °F	95°
	Specific Gravity @ P.T.	1.0
	Vapor Pressure @ P.T. - PSIA	
	Viscosity @ P.T. - SSU	
	Capacity - GPM	735
	Discharge Pressure - PSIG	
	Suction Pressure - PSIG	
	Differential Head - FT.	35
	NPSH: Available/Required - FT.	/7
	Minimum Flow - GPM	80
CONSTRUCTION	Suction Connection: Size/Rating	8" - 125# ANSI
	Facing/Position	Flat Face/Side
	Discharge Connection: Size/Rating	5" - 125# ANSI
	Facing/Position	Flat Face/Side
	Impeller Diameter: Design/Maximum	
	Bearing Type: Thrust/Radial	Ball
	Lubrication	Grease
	Oil Piping: (Yes) (No) /Type	
	Seals: Type/Manufacturer	Mechanical/Borg-Warner
	Coupling: Type/Manufacturer/Guard	Gear Spacer/Fast "B"/Yes
	Water Required: GPM/Pressure	
	Base Plate: Type/Material	Drip Lip - Fab. Steel
MATERIALS	Casing: Inner/Outer	ASTM A-48 Cl.30
	Impellers	ASTM B-143
	Diffusers	
	Shaft	AISI - 316 S.S.
	Shaft Sleeves	AISI - 316 S.S.
	Wear Rings: Case/Impeller	Bronze/None
	Packing	
TESTS	Hydrostatic/Witnessed	
	NPSH/Witnessed	
	Performance/Witnessed	

DRIVER: Type 10HP Motor 1800 RPM 3 Phase 60 Cycle TEFC Frame 215T

Manufacturer/Furnished By Westinghouse

WEIGHTS: Pump/Base/Driver Pump with base 740# Motor 120#

SPECIAL FEATURES & ACCESSORIES:

MID-VALLEY, INC. •ENGINEERS• •CONSTRUCTORS• HOUSTON, TEXAS	HORIZONTAL CENTRIFUGAL PUMP DATA SHEET COAGULATOR FEED PUMP FLORIDA POWER & LIGHT CO.-MIAMI, FLORIDA MARTIN PLANT UNITS #1 & #2	CONTRACT NO. CR-0163 SPEC. NO. M-107.1.5 PAGE NO. 22

DESCRIPTION	
Manufacturer	Ingersoll-Rand Company
Size and Type	5" x 4" x 12" HC (Dual)
Tag Number(s)	M-107.1.9
Serial Number(s)	
RPM/Number of Stages	1750/Single Stage
Design Efficiency - %/BHP/WR2	75/39/
Shut Off Head-FT.	141
Max. BHP Des Imp.	39
DESIGN CONDITIONS	
Liquid Pumped	Water
Pumping Temperature - °F	95°
Specific Gravity @ P.T.	1.0
Vapor Pressure @ P.T. - PSIA	
Viscosity @ P.T. - SSU	
Capacity - GPM	1000
Discharge Pressure - PSIG	
Suction Pressure - PSIG	
Differential Head - FT.	116
NPSH: Available/Required - FT.	/18
Minimum Flow - GPM	100
CONSTRUCTION	
Suction Connection: Size/Rating	5" - 125# ANSI
Facing/Position	Flat Face/Front
Discharge Connection: Size/Rating	4" - 125# ANSI
Facing/Position	Flat Face/Top
Impeller Diameter: Design/Maximum	
Bearing Type: Thrust/Radial	Ball
Lubrication	Oil
Oil Piping: (Yes) (No) /Type	
Seals: Type/Manufacturer	Mechanical/Borg-Warner
Coupling: Type/Manufacturer/Guard	Gear-Spacer/Fast-"B"/Yes
Water Required: GPM/Pressure	
Base Plate: Type/Material	Drip Lip/Fab. Steel
MATERIALS	
Casing: Inner/Outer	ASTM - A-48 C.I. 30
Impellers	ASTM B-143
Diffusers	
Shaft	AISI - 1045
Shaft Sleeves	SAE 660
Wear Rings: Case/Impeller	SAE 660/None
Packing	
TESTS	
Hydrostatic/Witnessed	
NPSH/Witnessed	
Performance/Witnessed	

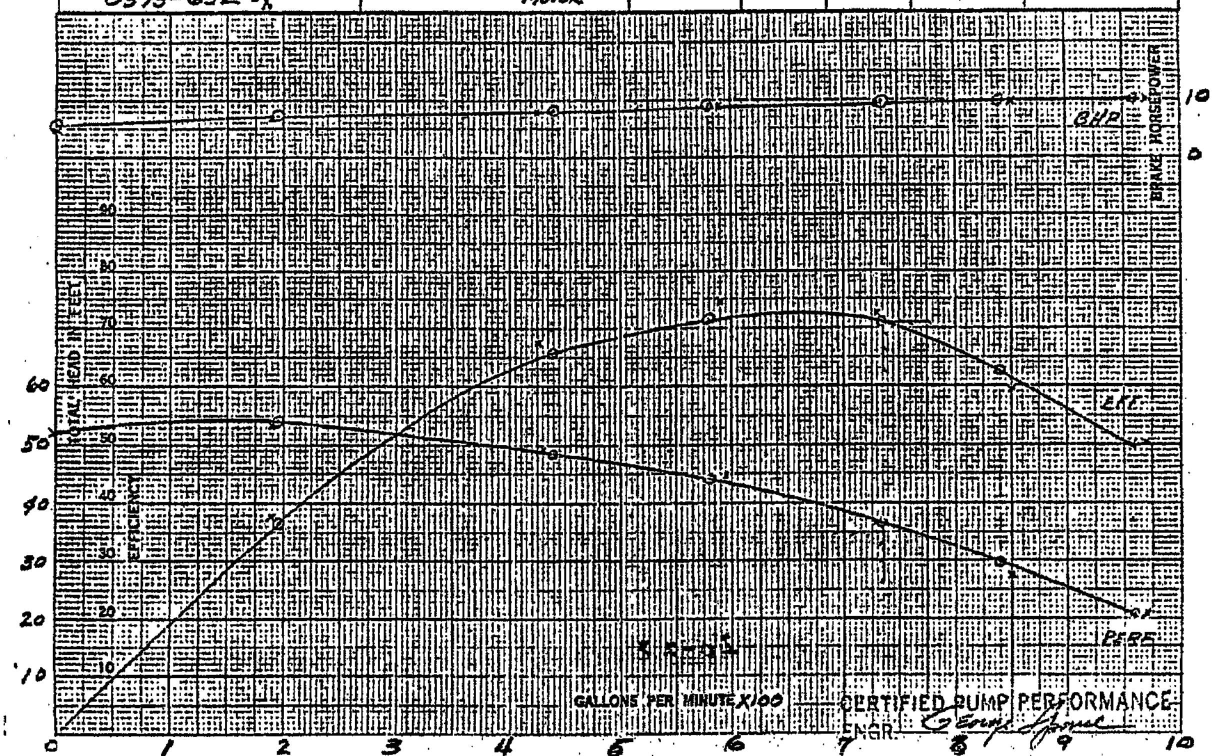
DRIVER: Type 50 HP Motor 1800 RPM 3 PHASE 60 Cycle TEFC Frame 346TS
Manufacturer/Furnished By Allis Chalmers
WEIGHTS: Pump/Base/Driver Pump with base 512# Motor 835#

SPECIAL FEATURES & ACCESSORIES:

MID-VALLEY, INC. •ENGINEERS• •CONSTRUCTORS• HOUSTON, TEXAS	HORIZONTAL CENTRIFUGAL PUMP DATA SHEET SAND FILTER BACKWASH PUMP FLORIDA POWER & LIGHT CO. - MIAMI, FLORIDA MARTIN PLANT UNITS #1 & #2	CONTRACT NO. CR-0163 SPEC. NO. M-107.1.9 PAGE NO. 23

P.O.# 85-4235-0049 (M107.1) CUST. ITEM #4 C#41502
TAG #85-4234 (CR0162) MARTIN UNIT #1
TAG # M107.1 5A & B COAGULATOR FEED PUMPS 1A & 1B

CUSTOMER Mid Valley INC.	ORDER CONDITIONS	PUMP 5X9SB		TEST RPM 1750		DATE 8/30/76
ORDER NO. 002-31654 ITEM 2	GPM 735 EFF 71%	IMPELLER	SHROUD DIA.	VANE DIA.	DIFFUSOR	CASING MAT'L.
SERIAL NBRS. 0375-651 -0 0375-652 -X	T. H. (FT.) 35' BHP	5583B	7 11/16"			IMP. MAT'L.
	RPM 1750 DRIVER 10 HP MOTOR					DIFF. MAT'L.



MID-VALLEY, INC. •ENGINEERS• •CONSTRUCTORS• HOUSTON, TEXAS	PUMP CURVE SHEET COAGULATOR FEED PUMPS 1A & 1B FLORIDA POWER & LIGHT CO. - MIAMI, FLORIDA MARTIN PLANT - UNITS #1 & #2	CONTRACT NO. CR-0163 SPEC. NO. M-107.1 PAGE NO. 24

FLORIDA POWER & LIGHT COMPANY

Department of Environmental Protection
Letter approving Corrective Action Plan
For FPL Martin Plant PWS #4431748

RRL-4
DOCKET NO. 070007-EI
FPL WITNESS: R.R. LABAUVE
EXHIBIT ___________
PAGES 1-3

Department of Environmental Protection

Jeb Bush
Governor

Southeast District
400 N. Congress Avenue, Suite 200
West Palm Beach, Florida 33401

Colleen M. Castille
Secretary

DEC - 1 2006

Received 12/7/2006

Craig W. Arcari
General Manager

Craig W. Arcari, Plant General Manager
Florida Power & Light Company Martin Plant
P.O. Box 176
Indiantown, Florida 34956-0176

SUBJECT: Consent Order in OGC File No.: 06-0744
Florida Power & Light Martin Plant PWS #4431748

Dear Mr. Arcari:

The Department would like to thank you for your correspondence of November 17, 2006 regarding the proposed corrective action plan (Plan) required by paragraph 5a of the referenced Consent Order. Based on the additional information provided in your November 17, 2006 letter, the Department hereby approves the Plan and proposed compliance schedule (copy attached). Since the pilot study is proposed to last no more than three months and the water from the pilot plant will not be discharged into the public water system, no Department permit is required for the pilot study.

Please keep the Department apprised as each milestone of the Plan is completed. If you have any questions regarding this matter, please contact Michele Owens of this office at (561) 681-6700 or via email at Michele.Owens@dep.state.fl.us.

Sincerely,

Todd R. Brown, C.P.M.
Environmental Manager
Water Facilities Compliance/Enforcement Program

TRB/mo

Enclosure (all)

cc: Harold A. Frediani, Jr., P.E., P.H., Golder Associates, Inc., 3730 Chamblee Tucker Road, Atlanta, GA 30341
Willie Welch – FPL, P.O. Box 176, Indiantown, FL, 34956 Willie_Welch@FPL.com
Jerry Toney – DEP/PSL Jerry.Toney@dep.state.fl.us
Jose Calas – DEP/WPB Jose.Calas@dep.state.fl.us

Florida Power & Light Company
Martin Plant, P. O. Box 176, Indiantown, FL 34956-0176

MO

DOCKET NO. 070007-EI
DEPT. LETTER APROVING
CORRECTIVE ACTION PLAN
EXHIBIT RRL-4, PAGE 2 OF 3

FPL

November 17, 2006

Mr. Todd Brown, Environmental Manager
Water Facilities Compliance/Enforcement Program
Florida Department of Environmental Protection
Southeast District Office
400 N. Congress Avenue, Suite 200
West Palm Beach, FL 33401

Re: Florida Power & Light Company
Martin Plant
PWS #4431748
OGC File No. 06-0744

Dear Mr. Brown:

FPL is in receipt of the Department's letter dated October 17, 2006, for the FPL Martin Plant nontransient noncommunity public water system, PWS #4431748. In response to the Department's letter, FPL has revised its schedule so that its pilot study will last less than three months. In addition, the water from the pilot study will not be discharged into the public water system. Provided are the revised interim milestone dates for the schedule provided in the Golder Associates submittal dated August 29, 2006. Please note that the remaining dates have not been changed.

- October 17, 2006 – FDEP issues written request for additional information (RFI);
- November 17, 2006 – FPL provides additional information to FDEP;
- December 20, 2006 – FDEP issues written approval of the plan;
- January 12, 2007 – FPL completes measurements of physical characteristics of aeration system, and takes synoptic samples of inlet and outlet water for both the aerator and the carbon filter, and sends those samples to the laboratory;
- January 26, 2007 – FPL receives results/report from laboratory;
- March 23, 2007 – Install pilot equipment for testing; – May 20
- June 20, 2007 – Complete testing of pilot; –

In addition, please address any future correspondence to Mr. Craig W. Arcari, FPL Martin Plant General Manager. If you have any questions or need additional information, please contact Willie Welch or Jill Watson at (772) 597-7211 and (561) 694-4304, respectively.

Sincerely,

Craig W. Arcari
Plant General Manager

cc:	Willie Welch	FPL Martin Plant
	Jill Watson	Power Generation
	Harold Frediani	Golder Associates

Florida Power & Light Company

Clean Air Interstate Rule

800 MW Cycling Project

Project Summary

FPL identified significant potential reductions in annual and ozone season NOx emissions through removal of the "must-run" status from the Martin and Manatee Plant 800 MW units. The "must run" status requires system dispatch to keep the 800 MW units from cycling off line during the May through September period once dispatched for load to avoid premature component failure from unit thermal cycling. FPL identified several strategies which, upon completion, would allow removal of "must run" status without subjecting the 800 MW units to premature failure from cycling off-line in response to reduced system load requirements.

Project Details

The analyses of components and systems which would require specific initiatives to allow for increased unit cycling identified seven (7) changes to component systems: 1)Condenser; 2)Superheater; 3)Economizer; 4)Aux Steam System; 5) Steam Turbine Components; 6)Water Treatment Plant upgrades; & 7)Instrument/Control upgrades. Systems and components were identified based on engineering analysis of impacts to unit reliability resulting from increased unit cycling operation. Figure 1 illustrates the specific project tasks which FPL has identified to allow reliable cycling of the 800 MW units.

Figure 1

ITEM	COUNTEMEASURE	BUDGET TYPE
2	Bullnose Thermocouples	Capital
6	Auxiliary Steam Warming	Capital
8	Steam Line Before Seat Drains	Capital
9	Induced Draft Fan Outlet Isolation Dampers	Capital
10	Nitrogen Blanket	Capital
11	Reheat Dissimilar Welds	Capital
12	Final Super Heater Tube Replace	Capital
13	Reheat Flex Modification	Capital
15	Water Treatment Plant	Capital
17	Condenser Retube	Capital
22	Water Induction Prevention	Capital
24	Rotor Stress Monitor	Capital
30	High Pressure Lower Shell Heating Blankets	Capital
1	Final Super Heater Outlet Header Condition Assessment	O & M
4	Automatic Heat Recovery Area Drains	O & M
5	Boiler Corrosion Fatigue Condition Assessment	O & M

20	Feed Water Recirculation Regulator Inspection	O & M
21	Low Pressure Turbine Inspections	O & M
26	Solid Particle Erosion Coating 2 Stages	O & M
33	Mid-Standard Low Friction Skids	O & M

FPL also identified additional initiatives that would be necessary for implementation of the 800 MW cycling project but were not exclusive to removal of the must run status. FPL intends to perform the additional tasks during planned outages recovering those costs through existing funding sources. Those activities and costs which were identified as specifically required for implementation of the 800 MW cycling project have been included in FPL's request for recovery under the ECRC CAIR docket.

Project Revenue Requirements

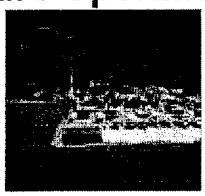
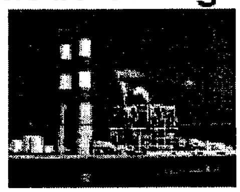
FPL has projected the total cost for implementation of the 800 MW cycling project at $109.3 million for the period of 2007 through project completion in 2010. FPL has identified $101.6 million of project costs which FPL proposes to recover through the ECRC. Figure 2 provides the project funding requirements for implementation of the 800 MW cycling strategy.

Figure 2
800 MW Cycling Project
ECRC Funding Requirement

	2007	2008	2009	2010	Total
Capital	$0	$31,215,000	$47,700,000	$18,150,000	$97,065,000
O&M	$0	$800,000	$2,500,000	$1,248,000	$4,548,000

AES 07016369-2-1
April 2007

Draft Report for Review and Recommendations for Martin and Manatee Power Stations with Future Operation Mode Changes

Phase 1: Analysis of Martin Unit 2 Cycling Impacts on Reliability, Future Costs, and Evaluation of Countermeasures to Reduce Impacts

Prepared By

G. Paul Grimsrud
Steven A. Lefton
James J. Yavelak
Dwight D. Agan
Joseph Lesiuk
Philip M. Besuner

APTECH

Prepared For

Florida Power & Light Company
Power Generation
700 Universe Boulevard
Juno Beach, FL 33408

Section 1
INTRODUCTION

1.1 BACKGROUND AND OBJECTIVES

Florida Power & Light Company (FPL) owns and operates four large gas-fired steam units at the Martin and Manatee power plants. The Martin plant went on-line commercially in 1980. It consists of two conventionally fired oil and gas-fired units. Each unit has a Foster Wheeler boiler, a Westinghouse turbine, and an ABB generator. These units were originally designed to burn oil and were retrofitted in 1985 to also burn natural gas. The Manatee plant first went on-line commercially in 1976. It too consists of two conventionally fired oil and gas-fired units. Each unit has a Foster Wheeler boiler, a Westinghouse turbine, and a Westinghouse generator. Like the Martin plant, the Manatee units were originally designed to burn oil only and were retrofitted in 2002 to also burn natural gas. The Unit 1 boiler at Manatee has been converted to include "re-burn" technology. The Unit 2 boiler is also in the process of installing the "re-burn" technology.

FPL anticipates that the "operating modes" for these units may involve more off-on cycling. FPL is concerned that increased cycling will cause accelerated damage to many unit components, causing increased equipment failures with resulting higher equipment forced outage rates and higher non-routine maintenance and capital replacement costs. The specific operating modes FPL desires to investigate are: (1) cycling off during weekends and (2) cycling off each weeknight (e.g., approximately five startups per week during the seasons of operation).

6.5 RECOMMENDATIONS ON SELECTED COUNTERMEASURES

Based on analyses presented in Table 6-4, we recommend the following cycling countermeasure for detailed design and implementation. These recommendations would apply for both the weekly cycling and daily cycling scenarios.

1. Add auxiliary steam from Unit 8 during periods before startups to lower temperature ramp rates and thermal fatigue in several components, including HP FW heaters; boiler pressure parts; air pre-heater; turbine casing and valves; main steam and hot reheat piping; steam jet air ejector, and the BFP. The economics presented in Table 6-4 do not include the possible benefit to Unit 8 of reducing off-on cycles of a CT. The avoidance of an overnight CT cycle could more than offset the cost of lost MWhs from the Unit 8 steam turbine. In comparing the incremental costs and benefits of including turbine warming from this system to using electric turbine blankets, we think it's more beneficial and less expensive to use the electric turbine blankets.

2. Add Automatic drains in HRA headers with motor-operated valves. This is based on our diagnosis that condensate is present in the lower HRA system left over from the boiler cold or warm condition that causes high thermal shocks to the HRA, division walls, and primary SH. This countermeasure is relatively inexpensive, and will likely significantly decrease problems in the HRA and division walls.

3. Add turbine blankets for keeping warm during shutdowns. We prefer this option compared to using an auxiliary steam source because it is a little cheaper, and much less costly to operate (per hour), meaning it could be used throughout the shutdowns rather than just before startups, thus reducing temperature ranges on warm and cold start cycles.

4. Install a nitrogen blanketing system for the boiler during shutdowns and for continuous use on the condensate storage tank. This system will allow better control of oxygen levels during cycling and help prevent corrosion in the boiler.

The candidate countermeasure that is near the margin in terms of cost-benefit is the condenser re-tube. Part of the reason for this is its high cost, about $7 million per unit. The re-tube option becomes economically viable when one of two adverse effects occur with the current condensers: (1) the condenser tube leaks become frequent and cause significant increases in EFOR and also carryover of bad water to the boiler and turbine and (2) the increasing number of plugged tubes causes condenser backpressure problems that increase heat rates. We think that if the Martin units go to daily cycling that the condensers will degrade very quickly causing and unacceptable level of EFORs. Thus, at least for the daily cycling scenario, we think this countermeasure should be designed and implemented. Since the condenser of Martin Unit 1 appears to be in the worst condition, it should probably be re-tubed first. If the Martin units go to weekly cycling FPL may want to take a wait-and-see approach to re-tubing, thus deferring a large capital cost. However, based on the recent studies on the condensers, they will need to be replaced soon in any case.

The countermeasures that don't appear to be economically viable are the :

1. Bypass system, which is quite expensive and does not offer as much benefit as the auxiliary steam system which is recommended

2. Motor-driven BFP, which appears to be too expensive. We think the auxiliary steam supply could be helpful in reducing BFP problems during initial startup

3. Replacement of selected sections of the SH and RH or replacement of DMWs, which is also too expensive. We think that more information on the damage mechanisms and remaining useful lives of these boiler sections are needed to justify the costs of these options.

Florida Power & Light Company

Clean Air Interstate Rule

Peaking Gas Turbine CEMS

Project Summary

FPL's Simple Cycle Gas Turbine Peaking Units located at the Port Everglades, Lauderdale and Ft. Myers plants are CAIR affected units which require compliance with the emission monitoring requirements under 40 CFR Part 75. Monitoring requirements under Part 75 provide several compliance options for peaking units. The flexibility for monitoring systems for peaking units allows facilities to implement less data intensive monitoring systems at lower costs exchange for typically higher estimated emissions. The Low Mass Emissions (LME) monitoring option under Part 75.19 is available to units which emit less than 100 NOx tons annually and 50 NOx tons during the May through September Ozone Season.

FPL had initially chosen to comply with the CAIR Part 75 monitoring requirements at the Gas Turbine Peaking Units through fuel flow monitoring methodology of Subpart B – Monitoring Provisions. Compliance utilizing the fuel flow methodology would have required a limited CEMS implementation to capture fuel flow to each unit and calculated the emissions through use of the emission factors provided by EPA for similar LME units.

During a subsequent review of the LME compliance option it was identified that an unacceptable risk to operation of the Gas Turbine Peaking Units could occur under several operating scenarios. The Part 75 rules do not allow for exceptions to compliance requirements and limitations for operating issues including emergency operations resulting from impacts of storms to FPL. FPL identified that exceedance of the LME limits for use of the fuel flow methodology was possible and theat exceedance of the limit would require compliance with full Part 75 CEMS requirements for all units within 12 months of the exceedance. Full Part 75 CEMS compliance would require the installation of stack sampling ports, pollutant analyzers, on data acquisition & reporting systems on each combustion turbine. FPL has estimated compliance with implementation of a full Part 75 CEMS on all of the Peaking Gas Turbine Units at a total cost in excess of $1.5 million for installation.

To reduce the potential exposure to a required implementation of full Part 75 CEMS on all Gas Turbine Peaking Units FPL has identified that compliance with the Similar Units methodology under the LME provisions would be a more cost effective alternative for CEMS compliance. FPL plans to implement the Similar Units provision through establishing emission factors from actual unit emission testing and monitoring of representative units. Emission factors will be developed for one of every four similar Gas Turbine Peaking Units to estimate emissions from the other units in the group.

The CAIR Gas Turbine Peaking Unit CEMS project requires the following milestones:

- Installation of emission testing ports on stacks of monitored units
- Purchase and installation of monitoring components
- Implementation of Data Acquisition & Handling Systems (DAHS)
- Compliance Testing & System Certification

FPL has estimated the cost for implementation of the Similar Units LME option for the CAIR Gas Turbine Peaking Unit CEMS at $396,273.

Title 40: Protection of Environment

PART 75—CONTINUOUS EMISSION MONITORING
Subpart B—Monitoring Provisions

Browse Previous

§ 75.19 Optional SO_2, NOX, and CO_2 emissions calculation for low mass emissions (LME) units.

(a) *Applicability and qualification.* (1) For units that meet the requirements of this paragraph (a)(1) and paragraphs (a)(2) and (b) of this section, the low mass emissions excepted methodology in paragraph (c) of this section may be used in lieu of continuous emission monitoring systems or, if applicable, in lieu of excepted methods under appendix D or E to this part, for the purpose of determining hourly heat input and hourly NO_X, SO_2, and CO_2 mass emissions under this part.

(i) A low mass emissions unit is an affected unit that is gas-fired, or oil-fired (as defined in §72.2 of this chapter), and for which:

(A) An initial demonstration is provided, in accordance with paragraph (a)(2) of this section, which shows that the unit emits:

(*1*) No more than 25 tons of SO_2 annually and less than 100 tons of NO_X annually, for Acid Rain Program affected units. If the unit is also subject to the provisions of subpart H of this part, no more than 50 of the allowable annual tons of NO_X may be emitted during the ozone season; or

(*2*) Less than 100 tons of NO_X annually *and* no more than 50 tons of NO_X during the ozone season, for non-Acid Rain Program units subject to the provisions of subpart H of this part, for which the owner or operator reports emissions data on a year-round basis, in accordance with §75.74(a) or §75.74(b); or

(*3*) No more than 50 tons of NO_X per ozone season, for non-Acid Rain Program units subject to the provisions of subpart H of this part, for which the owner or operator reports emissions data only during the ozone season, in accordance with §75.74(b); and

(B) An annual demonstration is provided thereafter, using one of the allowable methodologies in paragraph (c) of this section, showing that the low mass emissions unit continues to emit no more than the applicable number of tons of SO_2 and/or NO_X specified in paragraph (a)(1)(i)(A) of this section.

(C) This paragraph, (a)(1)(i)(C), applies only to a unit that is subject to an SO_2 emission limitation under the Acid Rain Program, and that combusts a gaseous fuel other than pipeline natural gas or natural gas (as defined in §72.2 of this chapter). The owner or operator of such a unit must quantify the sulfur content and variability of the gaseous fuel by performing the demonstration described in section 2.3.6 of appendix D to this part, in order for the unit to qualify for LME unit status. If the results of that demonstration show that the gaseous fuel qualifies under paragraph (b) of section 2.3.6 to use a default SO_2 emission rate to report SO_2 mass emissions under this part, the unit is eligible for LME unit status.

(ii) Each qualifying LME unit must start using the low mass emissions excepted methodology as follows:

(A) For a unit that reports emission data on a year-round basis, begin using the methodology in the first unit operating hour in the calendar year designated in the certification application as the first year that the methodology will be used; or

(B) For a unit that is subject to Subpart H of this part and that reports only during the ozone season according to §75.74(c), begin using the methodology in the first unit operating hour in the ozone season designated in the certification application as the first ozone season that the methodology will be used.

(C) For a new or newly-affected unit, see paragraph (b)(4) of this section for additional guidance.

(2) A unit may initially qualify as a low mass emissions unit if the designated representative submits a certification application to use the LME methodology (as described in §75.63(a)(1)(ii) and in this paragraph, (a)(2)) and the Administrator (or permitting authority, as applicable) certifies the use of such methodology. The certification application shall be submitted no later than 45 days prior to the date on which use of the low mass emissions methodology is expected to commence, and the application must contain:

(i) A statement identifying the projected date on which the LME methodology will first be used. The projected commencement date shall be consistent with paragraphs (a)(1)(ii) and (b)(4) of this section, as applicable; and

(ii) Either:

(A) Actual $SO_2$and/or NO_Xmass emissions data (as applicable) for each of the three calendar years (or ozone seasons) prior to the calendar year in which the certification application is submitted demonstrating to the satisfaction of the Administrator or (if applicable) the permitting authority, that the unit emitted less than the applicable number of tons of $SO_2$and/or NO_Xspecified in paragraph (a)(1)(i)(A) of this section. For the purposes of this paragraph, (a)(2)(ii)(A), the required actual SO_2or NO_Xmass emissions for each qualifying year or ozone season shall be determined using the SO_2, $NO_X$and heat input data reported to the Administrator in the electronic quarterly reports required under §75.64 or under the Ozone Transport Commission (OTC) NO_XBudget Trading Program. Notwithstanding this requirement, in the absence of such electronic reports, an estimate of the actual emissions for each of the previous three years (or ozone seasons) shall be provided, using either the maximum rated heat input methodology described in paragraph (c)(3)(i) of this section or procedures consistent with the long term fuel flow heat input methodology described in paragraph (c)(3)(ii) of this section, in conjunction with the appropriate SO_2or NO_Xemission rate from paragraph (c)(1)(i) of this section for SO_2, and paragraph (c)(1)(ii) or (c)(1)(iv) of this section for NO_X. Alternatively, the initial estimate of the NO_Xemission rate may be based on historical emission test data that is representative of operation at normal load or historical data from a CEMS certified under part 60 of this chapter or under a state CEM program; or

(B) When the three full years (or ozone seasons) of actual $SO_2$and NO_Xmass emissions data (or reliable estimates thereof) described under paragraph (a)(2)(ii)(A) of this section do not exist, the designated representative may submit an application to use the low mass emissions excepted methodology based upon a combination of actual historical $SO_2$and NO_Xmass emissions data and projected $SO_2$and NO_Xmass emissions, totaling three years (or ozone seasons). Except as provided in paragraph (a)(3) of this section, actual data must be used for any years (or ozone seasons) in which such data exists and projected data should be used for any remaining future years (or ozone seasons) needed to provide emissions data for three consecutive calender years (or ozone seasons). For example, if a unit commenced operation two years ago, the designated representative may submit actual, historical data for the previous two years and one year of projected emissions for the current calendar year or, for a new unit, the designated representative may submit three years of projected emissions, beginning with the current calendar year. Any actual or projected annual emissions must demonstrate to the satisfaction of the Administrator that the unit will emit less than the applicable number of tons of $SO_2$and/or NO_Xspecified in paragraph (a)(1)(i)(A) of this section. Projected emissions shall be calculated using either the appropriate default emission rates from paragraphs (c)(1)(i) and (c)(1)(ii) of this section (or, alternatively for NO_X, a conservative estimate of the NO_Xemission rate, as described in paragraph (a)(4) of this section), in conjunction with projections of unit operating hours or fuel type and fuel usage, according to one of the allowable calculation methodologies in paragraph (c) of this section; and

(iii) A description of the methodology from paragraph (c) of this section that will be used to demonstrate on-going compliance under paragraph (b) of this section; and

(iv) Appropriate documentation demonstrating that the unit is eligible to use projected emissions to qualify for LME status under paragraph (a)(3) of this section (if applicable).

(3) In the following circumstances, projected emissions for a future year (or years) may be used in lieu of the actual emissions data from one (or more) of the three years (or ozone seasons) preceding the year of the certification application:

(i) If the owner or operator takes an enforceable permit restriction on the number of annual or ozone season unit operating hours for the future year (or years), such that the unit will emit no more than the applicable number of tons of $SO_2$and/or NO_Xspecified in paragraph (a)(1)(i)(A) of this section; or

(ii) If the actual emissions for one (or more) of the three years (or ozone seasons) prior to the year of the certification application is not representative of the present and expected future emissions from the unit, because the owner or operator has recently installed emission controls on the unit.

(4) When the owner or operator elects to demonstrate initial LME qualification and on-going compliance using a fuel-and-unit-specific NO_Xemission rate in accordance with paragraph (c)(1)(iv) of this section, there will be instances (e.g., for a new or newly-affected unit) where it is not possible to determine that NO_Xemission rate prior to submitting the certification application. In such cases, if the generic default NO_Xemission rates in Table LM–2 of this section are inappropriately high for the unit, the owner or operator may use a more representative, but conservatively high estimate of the expected NO_Xemission rate, for the purposes of the initial monitoring plan submittal and to calculate the unit's projected annual or ozone season emissions under paragraph (a)(2)(ii)(B) of this section. For example, the NO_Xemission rate could, as described in paragraph (a)(2)(ii)(A) of this section, be estimated using historical CEM data or historical emission test data that is representative of operation at normal load. The NO_Xemission limit specified in the operating permit for the unit could also be used to estimate the NO_Xemission rate (except for units equipped with SCR or SNCR), or, consistent with paragraph (c)(1)(iv)(C)(*4*) of this section, for a unit that uses SCR or SNCR to control NO_Xemissions, an estimated default NO_Xemission rate of 0.15 lb/mmBtu could be used. However, these estimated NO_Xemission rates may not be used for reporting purposes in the time period extending from the first hour in which the LME methodology is used to the date and hour on which the fuel-and-unit-specific NO_Xemission rate testing is completed. Rather, in that interval, the owner or operator shall either report the appropriate default NO_Xemission rate from Table LM–2, or shall report the maximum potential NO_Xemission rate, calculated in accordance with §72.2 of this chapter and section 2.1.2.1 of appendix A to this part. Then, beginning with the first unit operating hour after completion of the tests, the appropriate default NO_Xemission rate (s) obtained from the fuel-and-unit-specific testing shall be used for emissions reporting.

(b) *On-going qualification and disqualification.* (1) Once a low mass emissions unit has qualified for and has started using the low mass emissions excepted methodology, an annual demonstration is required, showing that the unit continues to emit no more than the applicable number of tons of $SO_2$and/or NO_Xspecified in paragraph (a)(1)(i)(A) of this section. The calculation methodology used for the annual demonstration shall be the methodology described in the certification application under paragraph (a)(2)(iii) of this section.

(2) If any low mass emissions unit fails to provide the required annual demonstration under paragraph (b)(1) of this section, such that the calculated cumulative emissions for the unit exceed the applicable number of tons of $SO_2$and/or NO_Xspecified in paragraph (a)(1)(i)(A) of this section at the end of any calendar year or ozone season, then:

(i) The low mass emissions unit shall be disqualified from using the low mass emissions excepted methodology; and

(ii) The owner or operator of the low mass emissions unit shall install and certify monitoring systems that meet the requirements of §§75.11, 75.12, and 75.13, and shall report SO_2(Acid Rain Program units, only), NO_X, and CO_2(Acid Rain Program units, only) emissions data and heat input data from such monitoring systems by December 31 of the calendar year following the year in which the unit exceeded the number of tons of SO_2 and/or NO_X specified in paragraph (a)(1)(i)(A) of this section; and

(iii) If the required monitoring systems have not been installed and certified by the applicable deadline in paragraph (b)(2)(ii) of this section, the owner or operator shall report the following values for each unit operating hour, beginning with the first operating hour after the deadline and continuing until the monitoring systems have been provisionally certified: the maximum potential hourly heat input for the unit, as defined in §72.2 of this chapter; the SO_2 emissions, in lb/hr, calculated using the applicable default SO_2 emission rate from paragraph (c)(1)(i) of this section and the maximum potential hourly unit heat input; the CO_2 emissions, in tons/hr, calculated using the applicable default CO_2 emission rate from paragraph (c)(1)(iii) of this section and the maximum potential hourly unit heat input; and the maximum potential NO_X emission rate, as defined in §72.2 of this chapter.

(3) If a low mass emissions unit that initially qualifies to use the low mass emissions excepted methodology under this section changes fuels, such that a fuel other than those allowed for use in the low mass emissions methodology is combusted in the unit, the unit shall be disqualified from using the low mass emissions excepted methodology as of the first hour that the new fuel is combusted in the unit. The owner or operator shall install and certify SO_2 (Acid Rain Program units, only), NO_X, and CO_2 (Acid Rain Program units, only) and flow (if necessary) monitoring systems that meet the requirements of §§75.11, 75.12, and 75.13 prior to a change to such fuel, and shall report emissions data from such monitoring systems beginning with the date and hour on which the new fuel is first combusted in the unit. If the required monitoring systems are not installed and certified prior to the fuel switch, the owner or operator shall report (as applicable) the maximum potential concentration of SO_2, CO_2 and NO_X, the maximum potential NO_X emission rate, the maximum potential flowrate, the maximum potential hourly heat input and the maximum (or minimum, if appropriate) potential moisture percentage, from the date and hour of the fuel switch until the monitoring systems are certified or until probationary calibration error tests of the monitors are passed and the conditional data validation procedures in §75.20(b)(3) begin to be used. All maximum and minimum potential values shall be specific to the new fuel and shall be determined in a manner consistent with section 2 of appendix A to this part and §72.2 of this chapter. The owner or operator must notify the Administrator (or the permitting authority) in the case where a unit switches fuels without previously having installed and certified a SO_2, NO_X and CO_2 monitoring system meeting the requirements of §§75.11, 75.12, and 75.13.

(4) If a new of newly-affected unit initially qualifies to use the low mass emissions excepted methodology under this section and the owner or operator wants to use the low mass emissions methodology for the unit, he or she must:

(i) Keep the records specified in paragraph (c)(2) of this section, beginning with the date and hour of commencement of commercial operation, for a new unit subject to an Acid Rain emission limitation, and beginning with the date and hour of the commencement of operation, for a new unit subject to a NO_X mass reduction program under subpart H of this part. For newly-affected units, the records in paragraph (c)(2) of this section shall be kept as follows:

(A) For Acid Rain Program units, begin keeping the records as of the first hour of commercial operation of the unit following the date on which the unit becomes affected; or

(B) For units subject to a NO_X mass reduction program under subpart H of this part, begin keeping the records as of the first hour of unit operation following the date on which the unit becomes an affected unit;

(ii) Use these records to determine the cumulative heat input and SO_2, CO_2, and/or NO_X mass emissions in order to continue to qualify as a low mass emissions unit; and

(iii) Determine the cumulative SO_2 and/or NO_X mass emissions according to paragraph (c) of this section using the same procedures used after the certification deadline for the unit, for purposes of demonstrating eligibility to use the excepted methodology set forth in this section. For example, use the default emission rates in Tables LM–1, LM–2, and LM–3 of this section or use the fuel-and-unit-specific NO_X emission rate determined according to paragraph (c)(1)(iv) of this section. For Acid Rain Program LME units, the Administrator will not count SO_2 mass emissions calculated for the period between commencement of commercial operation and the certification deadline for the unit under §75.4 against

SO_2 allowances to be held in the unit account.

(5) A low mass emissions unit that has been disqualified from using the low mass emissions excepted methodology may subsequently submit an application to qualify again to use the low mass emissions methodology under paragraph (a)(2) of this section only if, following the non-compliant year (or ozone season), at least three full years (or ozone seasons) of actual, monitored emissions data is obtained showing that the unit emitted no more than the applicable number of tons of SO_2 and/or NO_X specified in paragraph (a)(1)(i)(A) of this section. Further, the designated representative or authorized account representative must certify in the application that the unit operation for the years or ozone seasons for which the emissions were monitored are representative of the projected future operation of the unit.

(c) *Low mass emissions excepted methodology, calculations, and values* —(1) *Determination of SO 2, NO X, and CO 2 emission rates.* (i) If the unit combusts only natural gas and/or fuel oil, use Table LM–1 of this section to determine the appropriate SO_2 emission rate for use in calculating hourly SO_2 mass emissions under this section (Acid Rain Program units, only). If the unit combusts gaseous fuel(s) other than natural gas, the owner or operator shall use the procedures in section 2.3.6 of appendix D to this part to document the total sulfur content of each such fuel and to determine the appropriate default SO_2 emission rate for each such fuel.

(ii) If the unit combusts only natural gas and/or fuel oil, use either the appropriate NO_X emission factor from Table LM–2 of this section, or a fuel-and-unit-specific NO_X emission rate determined according to paragraph (c)(1)(iv) of this section, to calculate hourly NO_X mass emissions under this section. If the unit combusts a gaseous fuel other than pipeline natural gas or natural gas, the owner or operator shall determine a fuel-and-unit-specific NO_X emission rate according to paragraph (c)(1)(iv) of this section.

(iii) If the unit combusts only natural gas and/or fuel oil, use Table LM–3 of this section to determine the appropriate CO_2 emission rate for use in calculating hourly CO_2 mass emissions under this section (Acid Rain Program units, only). If the unit combusts a gaseous fuel other than pipeline natural gas or natural gas, the owner or operator shall determine a fuel-and-unit-specific CO_2 emission rate for the fuel, as follows:

(A) Derive a carbon-based F-factor for the fuel, using fuel sampling and analysis, as described in section 3.3.6 of appendix F to this part; and

(B) Use Equation G–4 in appendix G to this part to derive the default CO_2 emission rate. Rearrange the equation, solving it for the ratio of W_{CO2}/H (this ratio will yield an emission rate, in units of tons/mmBtu). Then, substitute the carbon-based F-factor determined in paragraph (c)(1)(iii)(A) of this section into the rearranged equation to determine the default CO_2 emission rate for the unit.

(iv) In lieu of using the default NO_X emission rate from Table LM–2 of this section, the owner or operator may, for each fuel combusted by a low mass emissions unit, determine a fuel-and-unit-specific NO_X emission rate for the purpose of calculating NO_X mass emissions under this section. This option may be used by any unit which qualifies to use the low mass emission excepted methodology under paragraph (a) of this section, and also by groups of units which combust fuel from a common source of supply and which use the long term fuel flow methodology under paragraph (c)(3)(ii) of this section to determine heat input. The testing must be completed in a timely manner, such that the test results are reported electronically no later than the end of the calendar year or ozone season in which the LME methodology is first used. If this option is chosen, the following procedures shall be used.

(A) Except as otherwise provided in paragraphs (c)(1)(iv)(F), (c)(1)(iv)(G), and (c)(1)(iv)(I) of this section, determine a fuel-and-unit-specific NO_X emission rate by conducting a four load NO_X emission rate test procedure as specified in section 2.1 of appendix E to this part, for each type of fuel combusted in the unit. For a group of units sharing a common fuel supply, the appendix E testing must be performed on each individual unit in the group, unless some or all of the units in the group belong to an identical group of units, as defined in paragraph (c)(1)(iv)(B) of this section, in which case, representative testing may be conducted on units in the identical group of units, as described in paragraph (c)(1)(iv)(B) of this section. For the purposes of this section, make the following modifications to the appendix E test procedures:

(1) Do not measure the heat input as required under 2.1.3 of appendix E to this part.

(2) Do not plot the test results as specified under 2.1.6 of appendix E to this part.

(3) When using Method 20 for turbines do not correct the NO_X concentration to 15% O_2.

(4) If the testing is performed on an uncontrolled diffusion flame turbine, a correction to the observed average NO_X concentration from each run of the Method 20 test must be applied using the following Equation LM–1a.

$$NO_{X_{corr}} = NO_{X_{obs}} \left(\frac{P_r}{P_o}\right)^{0.5} e^{19(H_o-H_r)} \left(\frac{T_r}{T_a}\right)^{1.53} \qquad (Eq.\ LM\text{-}1a)$$

Where:

NO_Xcorr= Corrected NO_X concentration (ppm).

NO_Xobs= Average measured NO_X concentration for each run of the Method 20 test (ppm).

P_r= Average annual atmospheric pressure (or average ozone season atmospheric pressure for a Subpart H unit that reports data only during the ozone season) at the nearest weather station (e.g., a standardized NOAA weather station located at the airport) for the year (or ozone season) prior to the year of the test (mm Hg).

P_o= Observed atmospheric pressure during the test run (mm Hg).

H_r= Average annual atmospheric humidity ratio (or average ozone season humidity ratio for a Subpart H unit that reports data only during the ozone season) at the nearest weather station, for the year (or ozone season) prior to the year of the test (g H_2O/g air).

H_o= Observed humidity ratio during the test run (g H_2O/g air).

T_r= Average annual atmospheric temperature (or average ozone season atmospheric *temperature for a Subpart H unit that reports data only during the ozone season)* at the nearest weather station, for the year (or ozone season) prior to the year of the test (° K).

T_a= Observed atmospheric temperature during the test run (° K).

(B) *Representative appendix E testing may be done on low mass emission units in a group of identical* units. All of the units in a group of identical units must combust the same fuel type but do not have to share a common fuel supply.

(1) To be considered identical, all low mass emission units must be of the same size (based on maximum rated hourly heat input), manufacturer and model, and must have the same history of *modifications (e.g., have the same controls installed, the same types of burners and have undergone* major overhauls at the same frequency (based on hours of operation)). Also, under similar operating conditions, the stack or turbine outlet temperature of each unit must be within ±50 degrees Fahrenheit of the average stack or turbine outlet temperature for all of the units.

(2) If all of the low mass emission units in the group qualify as identical, then representative testing of the units in the group may be performed according to Table LM–4 of this section.

(3) [Reserved]

(*4*) If the acceptance criteria in paragraph (c)(1)(iv)(B)(*1*) of this section are not met then the group of low mass emission units is not considered an identical group of units and individual appendix E testing of each unit is required.

(*5*) Fuel and unit specific NO_X emission rates determined according to paragraphs (c)(1)(iv)(F) and (c)(1)(iv)(G) of this section may be used in lieu of appendix E testing for one or more low mass emission units in a group of identical units.

(C) Based on the results of the part 75 appendix E testing, determine the fuel-and-unit-specific NO_X emission rate as follows:

(*1*) Except for LME units that use selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) to control NO_X emissions, the highest three-run average NO_X emission rate obtained at any load in the appendix E test for a particular type of fuel shall be the fuel-and-unit-specific NO_X emission rate, for that type of fuel.

(*2*) [Reserved]

(*3*) For a group of identical low mass emissions units (except for units that use SCR or SNCR to control NO_X emissions), the fuel-and-unit-specific NO_X emission rate for all units in the group, for a particular type of fuel, shall be the highest three-run average NO_X emission rate obtained at any tested load from any unit tested in the group, for that type of fuel.

(*4*) Except as provided in paragraphs (c)(1)(iv)(C)(*7*) and (c)(1)(iv)(C)(*8*) of this section, for an individual low mass emissions unit which uses SCR or SNCR to control NO_X emissions, the fuel-and-unit-specific NO_X emission rate for each type of fuel combusted in the unit shall be the higher of:

(*i*) The highest three-run average emission rate from any load of the appendix E test for that type of fuel; or

(*ii*) 0.15 lb/mmBtu.

(*5*) [Reserved]

(*6*) Except as provided in paragraphs (c)(1)(iv)(C)(*7*) and (c)(1)(iv)(C)(*8*) of this section, for a group of identical low mass emissions units that are all equipped with SCR or SNCR to control NO_X emissions, the fuel-and-unit-specific NO_X emission rate for each unit in the group of units, for a particular type of fuel, shall be the higher of:

(*i*) The highest three-run average NO_X emission rate at any load from all appendix E tests of all tested units in the group, for that type of fuel; or

(*ii*) 0.15 lb/mmBtu.

(*7*) Notwithstanding the requirements of paragraphs (c)(1)(iv)(C)(*4*) and (c)(1)(iv)(C)(*6*) of this section, for a unit (or group of identical units) equipped with SCR (or SNCR) *and* water (or steam) injection to control NO_X emissions:

(*i*) If the appendix E testing is performed when the water (or steam) injection is in use *and* either upstream of the SCR or SNCR or during a time period when the SCR or SNCR is out of service; then

(*ii*) The highest three-run average emission rate from the appendix E testing may be used as the fuel-and-unit-specific NO_X emission rate for the unit (or, if applicable, for each unit in the group), for each unit operating hour in which the water-to-fuel ratio is within the acceptable range established during the appendix E testing.

(*8*) Notwithstanding the requirements of paragraphs (c)(1)(iv)(C)(*4*) and (c)(1)(iv)(C)(*6*) of this section, for a unit (or group of identical units) equipped with SCR (or SNCR) and uses dry low-NO_X technology to control NO_X emissions:

(*i*) If the appendix E testing is performed during a time period when the dry low-NO_X controls are in use, but the SCR or SNCR is out of service; then

(*ii*) The highest three-run average emission rate from the appendix E testing may be used as the fuel-and-unit-specific NO_X emission rate for the unit (or, if applicable, for each unit in the group), for each unit operating hour in which the parametric data described in paragraph (c)(1)(iv)(H)(2) of this section demonstrate that the dry low-NO_X controls are operating in the premixed or low-NO_X mode.

(*9*) For an individual combustion turbine (or a group of identical turbines) that operate principally at base load (or at a set point temperature), but are capable of operating at a higher peak load (or higher internal operating temperature), the fuel-and-unit-specific NO_X emission rate for the unit (or for each unit in the group) shall be as follows:

(*i*) If the testing is done only at base load, use the three-run average NO_X emission rate for base load operating hours and 1.15 times that emission rate for peak load operating hours; or

(*ii*) If the testing is done at both base load and peak load, use the three-run average NO_X emission rate from the base load testing for base load operating hours and the three-run average NO_X emission rate from the peak load testing for peak load operating hours.

(D) For each low mass emissions unit, or group of identical units for which the provisions of paragraph (c)(1)(iv) of this section are used to account for NO_X emission rate, the owner or operator shall determine a new fuel-and-unit-specific NO_X emission rate every five years (20 calendar quarters), unless changes in the fuel supply, physical changes to the unit, changes in the manner of unit operation, or changes to the emission controls occur which may cause a significant increase in the unit's actual NO_X emission rate. If such changes occur, the fuel-and-unit-specific NO_X emission rate(s) shall be re-determined according to paragraph (c)(1)(iv) of this section. Testing shall be done at the number of loads specified in paragraph (c)(1)(iv)(A) or (c)(1)(iv)(I) of this section, as applicable. If a low mass emissions unit belongs to a group of identical units and it is required to retest to determine a new fuel-and-unit-specific NO_X emission rate because of changes in the fuel supply, physical changes to the unit, changes in the manner of unit operation or changes to the emission controls occur which may cause a significant increase in the unit's actual NO_X emission rate, any other unit in that group of identical units is not required to re-determine the fuel-and-unit-specific NO_X emission rate unless such unit also undergoes changes in the fuel supply, physical changes to the unit, changes in the manner of unit operation or changes to the emission controls occur which may cause a significant increase in the unit's actual NO_X emission rates.

(E) Each low mass emissions unit or each low mass emissions unit in a group of identical units for which a fuel-and-unit-specific NO_X emission rate(s) are determined shall meet the quality assurance and quality control provisions of paragraph (e) of this section.

(F) Low mass emission units may use the results of appendix E testing, if such test results are available from a test conducted no more than five years prior to the time of initial certification, to determine the appropriate fuel-and-unit-specific NO_X emission rate(s). However, fuel-and-unit-specific NO_X emission rates from historical testing may not be used longer than five years after the appendix E testing was conducted.

(G) Low mass emissions units for which at least 3 years of quality-assured NO_X emission rate data from a NO_X-diluent CEMS and corresponding fuel usage data are available may determine fuel-and-unit-specific NO_X emission rates from the actual data using the following procedure. Separate the actual NO_X emission rate data into groups, according to the type of fuel combusted. Discard data from periods when multiple fuels were combusted. Each fuel-specific data set must contain at least 168 hours of data and must represent all normal operating ranges of the unit when combusting the fuel. Sort the data in each fuel-specific data set in ascending order according to NO_X emission rate. Determine the 95th percentile NO_x emission rate for each data set as defined in §72.2 of this chapter. Use the 95th percentile value for each data set as the fuel-and-unit-specific NO_x emission rate, except that for a unit that uses SCR or SNCR for NO_x emission control, if the 95th percentile value is less than 0.15 lb/mmBtu, a value of 0.15 lb/mmBtu shall be used as the fuel-and-unit-specific NO_x emission rate.

(H) For low mass emission units with add-on NO_x emission controls, and for units that use dry low-NO_x technology, the owner or operator shall, during every hour of unit operation during the test period, monitor and record parameters, as required under paragraph (e)(5) of this section, which indicate that the NO_x emission controls are operating properly. After the test period, these same parameters shall be monitored and recorded and kept for all operating hours in order to determine whether the NO_x controls are operating properly and to allow the determination of the correct NO_x emission rate as required under paragraph (c)(1)(iv) of this section.

(*1*) For low mass emission units with steam or water injection, the steam-to-fuel or water-to-fuel ratio used during the testing must be documented. The water-to-fuel or steam-to-fuel ratio must be maintained during unit operations for a unit to use the fuel and unit specific NO_x emission rate determined during the test. Owners or operators must include in the monitoring plan the acceptable range of the water-to-fuel or steam-to-fuel ratio, which will be used to indicate hourly, proper operation of the NO_x controls for each unit. The water-to-fuel or steam-to-fuel ratio shall be monitored and recorded during each hour of unit operation. If the water-to-fuel or steam-to-fuel ratio is not within the acceptable range in a given hour the fuel and unit specific NO_x emission rate may not be used for that hour, and the appropriate default NO_x emission rate from Table LM–2 shall be reported instead.

(*2*) For a low mass emissions unit that uses dry low-NO_x premix technology to control NO_x emissions, proper operation of the emission controls means that the unit is in the low-NO_x or premixed combustion mode, and fired with natural gas. Evidence of operation in the low-NO_x or premixed mode shall be provided by monitoring the appropriate turbine operating parameters. These parameters may include percentage of full load, turbine exhaust temperature, combustion reference temperature, compressor discharge pressure, fuel and air valve positions, dynamic pressure pulsations, internal guide vane (IGV) position, and flame detection or flame scanner condition. The acceptable values and ranges for all parameters monitored shall be specified in the monitoring plan for the unit, and the parameters shall be monitored during each subsequent operating hour. If one or more of these parameters is not within the acceptable range or at an acceptable value in a given operating hour, the fuel-and-unit-specific NO_x emission rate may not be used for that hour, and the appropriate default NO_x emission rate from Table LM–2 shall be reported instead. When the unit is fired with oil the appropriate default value from Table LM–2 shall be reported.

(*3*) For low mass emission units with other types of add-on NO_x controls, appropriate parameters and the acceptable range of the parameters which indicate hourly proper operation of the NO_x controls must be specified in the monitoring plan. These parameters shall be monitored during each subsequent operating hour. If any of these parameters are not within the acceptable range in a given operating hour, the fuel and unit specific NO_x emission rates may not be used in that hour, and the appropriate default NO_x emission rate from Table LM–2 shall be reported instead.

(I) Notwithstanding the requirements in paragraph (c)(1)(iv)(A) of this section, the appendix E testing to determine (or re-determine) the fuel-specific, unit-specific NO_x emission rate for a unit (or for each unit in a group of identical units) may be performed at fewer than four loads, under the following circumstances:

(*1*) Testing may be done at one load level if the data analysis described in paragraph (c)(1)(iv)(J) of this section is performed and the results show that the unit has operated (or all units in the group of identical units have operated) at a single load level for at least 85.0 percent of all operating hours in the previous three years (12 calendar quarters) prior to the calendar quarter of the appendix E testing. For combustion turbines that are operated to produce approximately constant output (in MW) but which use internal operating and exhaust temperatures and not the actual output in MW to control the operation of the turbine, the internal operating temperature set point may be used as a surrogate for load in demonstrating that the unit qualifies for single-load testing. If the data analysis shows that the unit does not qualify for single-load testing, testing may be done at two (or three) load levels if the unit has operated (or if all units in the group of identical units have operated) cumulatively at two (or three) load levels for at least 85.0 percent of all operating hours in the previous three years; or

(*2*) If a multiple-load appendix E test was initially performed for a unit (or group of identical units) to determine the fuel-and-unit specific NO_X emission rate, then the periodic retests required under paragraph (c)(1)(iv)(D) of this section may be single-load tests, performed at the load level for which the highest average NO_X emission rate was obtained in the initial test.

(J) To determine whether a unit qualifies for testing at fewer than four loads under paragraph (c)(1)(iv)(I) of this section, follow the procedures in paragraph (c)(1)(iv)(J)(*1*) or (c)(1)(iv)(J)(*2*) of this section, as applicable.

(*1*) Determine the range of operation of the unit, according to section 6.5.2.1 of appendix A to this part. Divide the range of operation into four equal load bands. For example, if the range of operation extends from 20 MW to 100 MW, the four equal load bands would be: band #1: from 20 MW to 40 MW; band #2: from 41 MW to 60 MW; band #3: from 61 MW to 80 MW; and band #4: from 81 to 100 MW. Then, perform a historical load analysis for all unit operating hours in the 12 calendar quarters preceding the quarter of the test. Alternatively, for sources that report emissions data only during the ozone season, the historical load analysis may be based on unit operation in the previous three ozone seasons, rather than unit operation in the previous 12 calendar quarters. Determine the percentage of the data that fall into each load band. For a unit that is not part of a group of identical units, if 85.0% or more of the data fall into one load band, single-load testing may be performed at any point within that load band. For a group of identical units, if each unit in the group meets the 85.0% criterion, then representative single-load testing within the load band may be performed. If the 85.0% criterion cannot be met to qualify for single-load testing but this criterion can be met cumulatively for two (or three) load levels, then testing may be performed at two (or three) loads instead of four.

(*2*) For a combustion turbine that uses exhaust temperature and not the actual output in megawatts to control the operation of the turbine (or for a group of identical units of this type), the owner or operator must document that the unit (or each unit in the group) has operated within ±10% of the set point temperature for 85.0% of the operating hours in the previous 12 calendar quarters to qualify for single-load testing. Alternatively, for sources that report emissions data only during the ozone season, the historical set point temperature analysis may be based on unit operation in the previous three ozone seasons, rather than unit operation in the previous 12 calendar quarters. When the set point temperature is used rather than unit load to justify single-load testing, the designated representative shall certify in the monitoring plan for the unit that this is the normal manner of unit operation and shall document the setpoint temperature.

(2) *Records of operating time, fuel usage, unit output and NO_X emission control operating status.* The owner or operator shall keep the following records on-site, for three years, in a form suitable for inspection, except that for unmanned facilities, the records may be kept at a central location, rather than on-site:

(i) For each low mass emissions unit, the owner or operator shall keep hourly records which indicate whether or not the unit operated during each clock hour of each calendar year. The owner or operator may report partial operating hours or may assume that for each hour the unit operated the operating time is a whole hour. Units using partial operating hours and the maximum rated hourly heat input to calculate heat input for each hour must report partial operating hours.

(ii) For each low mass emissions unit, the owner or operator shall keep hourly records indicating the type (s) of fuel(s) combusted in the unit during each hour of unit operation.

(iii) For each low mass emissions unit using the long term fuel flow methodology under paragraph (c)(3)(ii) of this section to determine hourly heat input, the owner or operator shall keep hourly records of unit load (in megawatts or thousands of pounds of steam per hour), for the purpose of apportioning heat input to the individual unit operating hours.

(iv) For each low mass emissions unit with add-on NO_X emission controls of any kind and each unit that uses dry low-NO_X technology, the owner or operator shall keep hourly records of the hourly value of the parameter(s) specified in (c)(1)(iv)(H) of this section used to indicate proper operation of the unit's NO_X controls.

(3) *Heat input.* Hourly, quarterly and annual heat input for a low mass emissions unit shall be determined

using either the maximum rated hourly heat input method under paragraph (c)(3)(i) of this section or the long term fuel flow method under paragraph (c)(3)(ii) of this section.

(i) *Maximum rated hourly heat input method.* (A) For the purposes of the mass emission calculation methodology of paragraph (c)(3) of this section, HI_{hr}, the hourly heat input (mmBtu) to a low mass emissions unit shall be deemed to equal the maximum rated hourly heat input, as defined in §72.2 of this chapter, multiplied by the operating time of the unit for each hour. The owner or operator may choose to record and report partial operating hours or may assume that a unit operated for a whole hour for each hour the unit operated. However, the owner or operator of a unit may petition the Administrator under §75.66 for a lower value for maximum rated hourly heat input than that defined in §72.2 of this chapter. The Administrator may approve such lower value if the owner or operator demonstrates that either the maximum hourly heat input specified by the manufacturer or the highest observed hourly heat input, or both, are not representative, and such a lower value is representative, of the unit's current capabilities because modifications have been made to the unit, limiting its capacity permanently.

(B) The quarterly heat input, HI_{qtr}, in mmBtu, shall be determined using Equation LM–1:

$$HI_{qtr} = \sum_{1}^{N} HI_{hr} \qquad (Eq.\ LM\text{-}1)$$

Where:

n = Number of unit operating hours in the quarter.

HI hr= Hourly heat input under paragraph (c)(3)(i)(A) of this section (mmBtu).

(C) The year-to-date cumulative heat input (mmBtu) shall be the sum of the quarterly heat input values for all of the calendar quarters in the year to date.

(D) For a unit subject to the provisions of subpart H of this part, which is not required to report emission data on a year-round basis and elects to report only during the ozone season, the quarterly heat input for the second calendar quarter of the year shall, for compliance purposes, include only the heat input for the months of May and June, and the cumulative ozone season heat input shall be the sum of the heat input values for May, June and the third calendar quarter of the year.

(ii) *Long term fuel flow heat input method.* The owner or operator may, for the purpose of demonstrating that a low mass emissions unit or group of low mass emission units sharing a common fuel supply meets the requirements of this section, use records of long-term fuel flow, to calculate hourly heat input to a low mass emissions unit.

(A) This option may be used for a group of low mass emission units only if:

(*1*) The low mass emission units combust fuel from a common source of supply; and

(*2*) Records are kept of the total amount of fuel combusted by the group of low mass emission units and the hourly output (in megawatts or pounds of steam) from each unit in the group; and

(*3*) All of the units in the group are low mass emission units.

(B) For each fuel used during the quarter, the volume in standard cubic feet (for gas) or gallons (for oil) may be determined using any of the following methods;

(*1*) Fuel billing records (for low mass emission units, or groups of low mass emission units, which purchase fuel from non-affiliated sources);

(*2*) American Petroleum Institute (API) standard, American Petroleum Institute (API) Petroleum Measurement Standards, Chapter 3, Tank Gauging: Section 1A, Standard Practice for the Manual Gauging of Petroleum and Petroleum Products, December 1994; Section 1B, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Tanks by Automatic Tank Gauging, April 1992 (reaffirmed January 1997); Section 2, Standard Practice for Gauging Petroleum and Petroleum Products in Tank Cars, September 1995; Section 3, Standard Practice for Level Measurement of Liquid Hydrocarbons in Stationary Pressurized Storage Tanks by Automatic Tank Gauging, June 1996; Section 4, Standard Practice for Level Measurement of Liquid Hydrocarbons on Marine Vessels by Automatic Tank Gauging, April 1995; and Section 5, Standard Practice for Level Measurement of Light Hydrocarbon Liquids Onboard Marine Vessels by Automatic Tank Gauging, March 1997; Shop Testing of Automatic Liquid Level Gages, Bulletin 2509 B, December 1961 (Reaffirmed August 1987, October 1992) (incorporated by reference under §75.6); or;

(*3*) A fuel flow meter certified and maintained according to appendix D to this part.

(C) Except as provided in paragraph (c)(3)(ii)(C)(*3*) of this section, for each fuel combusted during a quarter, the gross calorific value of the fuel shall be determined by either:

(*1*) Using the applicable procedures for gas and oil analysis in sections 2.2 and 2.3 of appendix D to this part. If this option is chosen the highest gross calorific value recorded during the previous calendar year shall be used (or, for a new or newly-affected unit, if there are no sample results from the previous year, use the highest GCV from the samples taken in the current year); or

(*2*) Using the appropriate default gross calorific value listed in Table LM–5 of this section.

(*3*) For gaseous fuels other than pipeline natural gas or natural gas, the GCV sampling frequency shall be daily unless the results of a demonstration under section 2.3.5 of appendix D to this part show that the fuel has a low GCV variability and qualifies for monthly sampling. If daily GCV sampling is required, use the highest GCV obtained in the calendar quarter as GCV_{max} in Equation LM–3, of this section.

(D) If Eq. LM–2 is used for heat input determination, the specific gravity of each type of fuel oil combusted during the quarter shall be determined either by:

(*1*) Using the procedures in section 2.2.6 of appendix D to this part. If this option is chosen, use the highest specific gravity value recorded during the previous calendar year (or, for a new or newly-affected unit, if there are no sample results from the previous year, use the highest specific gravity from the samples taken in the current year); or

(*2*) Using the appropriate default specific gravity value in Table LM–6 of this section.

(E) The quarterly heat input from each type of fuel combusted during the quarter by a low mass emissions unit or group of low mass emissions units sharing a common fuel supply shall be determined using either Equation LM–2 or Equation LM–3 for oil (as applicable to the method used to quantify oil usage) and Equation LM–3 for gaseous fuels. For a unit subject to the provisions of subpart H of this part, which is not required to report emission data on a year-round basis and elects to report only during the ozone season, the quarterly heat input for the second calendar quarter of the year shall include only the heat input for the months of May and June.

$$HI_{fuel\text{-}qtr} = M_{qtr} \frac{GCV_{max}}{10^6} \qquad \text{Eq. LM-2 (for fuel oil)}$$

Where:

HI fuel-qtr= Quarterly total heat input from oil (mmBtu).

M_{qtr}= Mass of oil consumed during the quarter, determined as the product of the volume of oil under paragraph (c)(3)(ii)(B) of this section and the specific gravity under paragraph (c)(3)(ii)(D) of this section (lb).

GCV max= Gross calorific value of oil, as determined under paragraph (c)(3)(ii)(C) of this section (Btu/lb)

10^6 = Conversion of Btu to mmBtu.

$$HI_{fuel\text{-}qtr} = Q_{qtr} \frac{GCV_{max}}{10^6} \quad \text{Eq. LM-3 (for gaseous fuel or fuel oil)}$$

Where:

HI fuel-qtr= Quarterly heat input from gaseous fuel or fuel oil (mmBtu).

Q_{qtr}= Volume of gaseous fuel or fuel oil combusted during the quarter, as determined under paragraph (c)(3)(ii)(B) of this section standard cubic feet (scf) or (gal), as applicable.

GCV_{max}= Gross calorific value of the gaseous fuel or fuel oil combusted during the quarter, as determined under paragraph (c)(3)(ii)(C) of this section (Btu/scf) or (Btu/gal), as applicable.

10^6 = Conversion of Btu to mmBtu.

(F) Use Eq. LM–4 to calculate HIqtr-total, the quarterly heat input (mmBtu) for all fuels. HIqtr-totalshall be the sum of the HIfuel-qtrvalues determined using Equations LM–2 and LM–3.

$$HI_{qtr\text{-}total} = \sum_{all\text{-}fuels} \mathrm{HI}_{fuel\text{-}qtr} \quad (Eq.\ \text{LM-4})$$

(G) The year-to-date cumulative heat input (mmBtu) for all fuels shall be the sum of all quarterly total heat input (HIqtr-total) values for all calendar quarters in the year to date. For a unit subject to the provisions of subpart H of this part, which is not required to report emission data on a year-round basis and elects to report only during the ozone season, the cumulative ozone season heat input shall be the sum of the quarterly heat input values for the second and third calendar quarters of the year.

(H) For each low mass emissions unit or each low mass emissions unit in a group of identical units, the owner or operator shall determine the cumulative quarterly unit load in megawatts or thousands of pounds of steam per hour. The quarterly cumulative unit load shall be the sum of the hourly unit load values recorded under paragraph (c)(2) of this section and shall be determined using Equations LM–5 or LM–6. For a unit subject to the provisions of subpart H of this part, which is not required to report emission data on a year-round basis and elects to report only during the ozone season, the quarterly cumulative load for the second calendar quarter of the year shall include only the unit loads for the months of May and June.

$$MW_{qtr} = \sum_{all\text{-}hours} \mathrm{MW} \quad Eq.\ \text{LM-5 (for MW output)}$$

$$ST_{qtr} = \sum_{all\text{-}hours} \mathrm{ST} \quad Eq.\ \text{LM-6 (for steam output)}$$

Where:

MW_{qtr}=Sum of all unit operating loads recorded during the quarter by the unit (MW).

ST fuel-qtr= Sum of all hourly steam loads recorded during the quarter by the unit (klb of steam/hr).

MW = Unit operating load for a particular unit operating hour (MW).

ST = Unit steam load for a particular unit operating hour (klb of steam/hr).

(I) For a low mass emissions unit that is not included in a group of low mass emission units sharing a common fuel supply, apportion the total heat input for the quarter, HIqtr-totalto each hour of unit operation using either Equation LM–7 or LM–8:

$$HI_{hr} = HI_{qtr\text{-}total}\frac{MW_{hr}}{MW_{qtr}}$$

(Eq LM–7 for MW output)

$$HI_{hr} = HI_{qtr\text{-}total}\frac{ST_{hr}}{ST_{qtr}}$$

(Eq LM–8 for steam output)

Where:

HI_{hr}= Hourly heat input to the unit (mmBtu).

MW_{hr}= Hourly operating load for the unit (MW).

ST_{hr}= Hourly steam load for the unit (klb of steam/hr).

(J) For each low mass emissions unit that is included in a group of units sharing a common fuel supply, apportion the total heat input for the quarter, HIqtr-totalto each hour of operation using either Equation LM–7a or LM–8a:

$$HI_{hr} = HI_{qtr\text{-}total}\frac{MW_{hr}}{\sum_{all\text{-}units} MW_{qtr}}$$

(Eq LM–7a for MW output)

$$HI_{hr} = HI_{qtr\text{-}total}\frac{ST_{hr}}{\sum_{all\text{-}units} ST_{qtr}}$$

(Eq LM–8a for steam output)

Where:

HI_{hr}= Hourly heat input to the individual unit (mmBtu).

MW_{hr}= Hourly operating load for the individual unit (MW).

ST_{hr}= Hourly steam load for the individual unit (klb of steam/hr).

Σ *MW* qtr= Sum of the quarterly operating

all-units loads (from Eq. LM–5) for all units in the group (MW).

Σ *ST* qtr= Sum of the quarterly steam

all-units loads (from Eq. LM–6) for all units in the group (klb of steam/hr)

(4) *Calculation of SO 2, NO X and CO 2 mass emissions.* The owner or operator shall, for the purpose of demonstrating that a low mass emissions unit meets the requirements of this section, calculate SO_2, NO_X and CO_2 mass emissions in accordance with the following.

(i) *SO 2 mass emissions.* (A) The hourly SO_2 mass emissions (lbs) for a low mass emissions unit (Acid Rain Program units, only) shall be determined using Equation LM–9 and the appropriate fuel-based SO_2 emission factor from Table LM–1 of this section for the fuels combusted in that hour. If more than one fuel is combusted in the hour, use the highest emission factor for all of the fuels combusted in the hour. If records are missing as to which fuel was combusted in the hour, use the highest emission factor for all of the fuels capable of being combusted in the unit.

$W_{SO2} = EF_{SO2} \times HI_{hr}$ (Eq. LM–9)

Where:

W_{SO2} = Hourly SO_2 mass emissions (lbs.)

EF_{SO2} = Either the SO_2 emission factor from Table LM–1 of this section or the fuel-and-unit-specific SO_2 emission rate from paragraph (c)(1)(i) of this section (lb/mmBtu).

HI_{hr} = Either the maximum rated hourly heat input under paragraph (c)(3)(i)(A) of this section or the hourly heat input under paragraph (c)(3)(ii) of this section (mmBtu).

(B) The quarterly SO_2 mass emissions (tons) for the low mass emissions unit shall be the sum of all the hourly SO_2 mass emissions in the quarter, as determined under paragraph (c)(4)(i)(A) of this section, divided by 2000 lb/ton.

(C) The year-to-date cumulative SO_2 mass emissions (tons) for the low mass emissions unit shall be the sum of the quarterly SO_2 mass emissions, as determined under paragraph (c)(4)(i)(B) of this section, for all of the calendar quarters in the year to date.

(ii) *NO X mass emissions.* (A) The hourly NO_X mass emissions for the low mass emissions unit (lbs) shall be determined using Equation LM–10. If more than one fuel is combusted in the hour, use the highest emission rate for all of the fuels combusted in the hour. If records are missing as to which fuel was combusted in the hour, use the highest emission factor for all of the fuels capable of being combusted in the unit. For low mass emission units with NO_X emission controls of any kind and for which a fuel-and-unit-specific NO_X emission rate is determined under paragraph (c)(1)(iv) of this section, for any hour in which the parameters under paragraph (c)(1)(iv)(A) of this section do not show that the NO_X emission controls are operating properly, use the NO_X emission rate from Table LM–2 of this section for the fuel combusted during the hour with the highest NO_X emission rate.

$W_{NOX} = EF_{NOX} \times HI_{hr}$ (Eq. LM–10)

Where:

W_{NOX} = Hourly NO_X mass emissions (lbs).

EF_{NOX} = Either the NO_X emission factor from Table LM–2 of this section or the fuel- and unit-specific NO_X emission rate determined under paragraph (c)(1)(iv) of this section (lb/mmBtu).

HI_{hr} = Either the maximum rated hourly heat input from paragraph (c)(3)(i)(A) of this section or the hourly heat input as determined under paragraph(c)(3)(ii) of this section (mmBtu).

(B) The quarterly NO_X mass emissions (tons) for the low mass emissions unit shall be the sum of all of the hourly NO_X mass emissions in the quarter, as determined under paragraph (c)(4)(ii)(A) of this section, divided by 2000 lb/ton.

(C) The year-to-date cumulative NO_X mass emissions (tons) for the low mass emissions unit shall be the sum of the quarterly NO_X mass emissions, as determined under paragraph (c)(4)(ii)(B) of this section, for all of the calendar quarters in the year to date. For a unit subject to the provisions of subpart H of this part, which is not required to report emission data on a year-round basis and elects to report only during the ozone season, the ozone season NO_X mass emissions for the unit shall be the sum of the quarterly NO_X mass emissions, as determined under paragraph (c)(4)(ii)(B) of this section, for the second and third calendar quarters of the year, and the second quarter report shall include emissions data only for May and June.

(iii) *CO 2 Mass Emissions.* (A) The hourly CO_2 mass emissions (tons) for the affected low mass emissions unit (Acid Rain Program units, only) shall be determined using Equation LM–11 and the appropriate fuel-based CO_2 emission factor from Table LM–3 of this section for the fuel being combusted in that hour. If more than one fuel is combusted in the hour, use the highest emission factor for all of the fuels combusted in the hour. If records are missing as to which fuel was combusted in the hour, use the highest emission factor for all of the fuels capable of being combusted in the unit.

$WCO_2 = EFCO_2 \times HI_{hr}$ (Eq. LM–11)

Where:

WCO_2 = Hourly CO_2 mass emissions (tons).

EF CO2= Either the fuel-based CO_2 emission factor from Table LM–3 of this section or the fuel-and-unit-specific CO_2 emission rate from paragraph (c)(1)(iii) of this section (tons/mmBtu).

HI_{hr} = Either the maximum rated hourly heat input from paragraph (c)(3)(i)(A) of this section or the hourly heat input as determined under paragraph (c)(3)(ii) of this section (mmBtu).

(B) The quarterly CO_2 mass emissions (tons) for the low mass emissions unit shall be the sum of all of the hourly CO_2 mass emissions in the quarter, as determined under paragraph (c)(4)(iii)(A)of this section.

(C) The year-to-date cumulative CO_2 mass emissions (tons) for the low mass emissions unit shall be the sum of all of the quarterly CO_2 mass emissions, as determined under paragraph (c)(4)(iii)(B) of this section, for all of the calendar quarters in the year to date.

(d) Each unit that qualifies under this section to use the low mass emissions methodology must follow the recordkeeping and reporting requirements pertaining to low mass emissions units in subparts F and G of this part.

(e) The quality control and quality assurance requirements in §75.21 are not applicable to a low mass emissions unit for which the low mass emissions excepted methodology under paragraph (c) of this section is being used in lieu of a continuous emission monitoring system or an excepted monitoring system under appendix D or E to this part, except for fuel flowmeters used to meet the provisions in paragraph (c)(3)(ii) of this section. However, the owner or operator of a low mass emissions unit shall implement the following quality assurance and quality control provisions:

(1) For low mass emission units or groups of units which use the long term fuel flow methodology under paragraph (c)(3)(ii) of this section and which use fuel billing records to determine fuel usage, the owner or operator shall keep, at the facility, for three years, the records of the fuel billing statements used for long term fuel flow determinations.

(2) For low mass emissions units or groups of units which use the long term fuel flow methodology under

paragraph (c)(3)(ii) of this section and which use one of the methods specified in paragraph (c)(3)(ii)(B) (2) of this section to determine fuel usage, the owner or operator shall keep, at the facility, a copy of the standard used and shall keep records, for three years, of all measurements obtained for each quarter using the methodology.

(3) For low mass emission units or groups of units which use the long term fuel flow methodology under paragraph (c)(3)(ii) of this section and which use a certified fuel flow meter to determine fuel usage, the owner or operator shall comply with the quality control quality assurance requirements for a fuel flow meter under section 2.1.6 of appendix D of this part.

(4) For each low mass emissions unit for which fuel-and-unit-specific NO_X emission rates are determined in accordance with paragraph (c)(1)(iv) of this section, the owner or operator shall keep, at the facility, records which document the results of all NO_X emission rate tests conducted according to appendix E to this part. If CEMS data are used to determine the fuel-and-unit-specific NO_X emission rates under paragraph (c)(1)(iv)(G) of this section, the owner or operator shall keep, at the facility, records of the CEMS data and the data analysis performed to determine a fuel-and-unit-specific NO_X emission rate. The appendix E test records and historical CEMS data records shall be kept until the fuel and unit specific NO_X emission rates are re-determined.

(5) For each low mass emissions unit for which fuel-and-unit-specific NO_X emission rates are determined in accordance with paragraph (c)(1)(iv) of this section and which has add-on NO_X emission controls of any kind or uses dry low-NO_X technology, the owner or operator shall develop and keep on-site a quality assurance plan which explains the procedures used to document proper operation of the NO_X emission controls. The plan shall include the parameters monitored (e.g., water-to-fuel ratio) and the acceptable ranges for each parameter used to determine proper operation of the unit's NO_X controls.

(6) For unmanned facilities, the records required by paragraphs (e)(1), (e)(2) and (e)(4) of this section may be kept at a central location, rather than at the facility.

Table LM–1—SO_2 Emission Factors (lb/mmBtu) for Various Fuel Types

Fuel type	SO_2 emission factors
Pipeline Natural Gas	0.0006 lb/mmBtu.
Other Natural Gas	0.06 lb/mmBtu.
Residual Oil	2.1 lb/mmBtu.
Diesel Fuel	0.5 lb/mmBtu.

Table LM–2—NO_X Emission Rates (lb/mmBtu) for Various Boiler/Fuel Types

Unit type	Fuel type	NO_X emission rate
Turbine	Gas	0.7
Turbine	Oil	1.2
Boiler	Gas	1.5
Boiler	Oil	2

Table LM-3—CO_2 Emission Factors (ton/mmBtu) for Gas and Oil

Fuel type	CO_2 emission factors
Pipeline (or other) Natural Gas	0.059 ton/mmBtu.
Oil	0.081 ton/mmBtu.

Table LM-4—Identical Unit Testing Requirements

Number of identical units in the group	Number of appendix E tests required
2	1
3 to 6	2
7	3
>7	n tests; wheren n = number of units divided by 3 and rounded to nearest integer.

Table LM-5—Default Gross Calorific Values (GCVs) for Various Fuels

Fuel	GCV for use in equation LM-2 or LM-3
Pipeline Natural Gas	1050 Btu/scf.
Other Natural Gas	1100 Btu/scf.
Residual Oil	19,700 Btu/lb or 167,500 Btu/gallon.
Diesel Fuel	20,500 Btu/lb or 151,700 Btu/gallon.

Table LM-6—Default Specific Gravity Values for Fuel Oil

Fuel	Specific gravity (lb/gal)
Residual Oil	8.5
Diesel Fuel	7.4

[63 FR 57500, Oct. 27, 1998, as amended at 64 FR 28592, May 26, 1999; 64 FR 37582, July 12, 1999; 67 FR 40424, 40425, June 12, 2002; 67 FR 53504, Aug. 16, 2002]

Florida Power & Light Company

Clean Air Visibility Rule

Best Available Retrofit Technology (BART)/ Reasonable Progress Control Technology (RPCT) Project

Project Summary

The results from the BART exemption modeling analysis and the BART Determination Analysis conducted by FPL's consultant , Golder Associates, indicated that FPL's fossil units were exempt with the exception of Turkey Point Fossil Units 1 & 2 which are located adjacent to the Everglades National Park Class 1 area. Final recommendations for BART controls at Turkey Point will be presented to the FDEP based on the analysis results of the five evaluation criteria presented in the final regulations.

In June 2007 FDEP held a Reasonable Progress Rulemaking Workshop to identify reductions which may be required beyond BART. The Department identified 12 of FPL's oil-burning units as Proposed Sources Subject to Reasonable Progress Four-Factor analysis. The Department has initiated new Rulemaking (62-296.341) – "Regional Haze - Reasonable Progress Control Technology (RPCT)" for evaluation of impacts to Class 1 Areas by affected sources. Under the proposed Rule our FPL's sources will have to undergo a 4-factor evaluation for selecting the appropriate control technology to mitigate visibility impacts at one or more Federally Mandated Class 1 Areas, and submit Air Construction permit applications by Jan 31, 2008. Installation of the controls must be in place no later than December 31, 2013.

To determine whether FPL's oil burning units will be affected by the proposed rule, FPL plans to engage a consultant to prepare RPCT analyses required in Rule 62.296.341 Florida Administrative Code (F.A.C.) for FPL facilities identified by Florida Department of Environmental Protection (FDEP). The facilities identified by FDEP are Turkey Point Units 1 and 2, Port Everglades Units 1 through 4, Riviera Units 3 and 4, Martin Units 1 and 2, and Manatee Units 1 and 2. Although Cape Canaveral has not been identified, FDEP has not finalized the rule and the potential exists that this facility may be included.

The scope of work will be a control technology analysis meeting the requirements of 40 Code of Federal Regulations (CFR) Part 51 Appendix Y, Section IV.D. While the rule has not been finalized, recent discussions (7-19-07) with the Trina Vielhauer, Chief of the FDEP Bureau of Air Regulation indicate that air modeling to assess control effectiveness would not be part of the FDEP RPCT evaluation as stated in the EPA regulations. FPL has projected a year 2007 project cost of $25,000 in O&M costs for the required analyses. Exhibit C of this filing discusses FPL's CAVR compliance plan.

BART EXEMPTION MODELING ANALYSIS FOR AFFECTED FPL PLANTS UPDATED APRIL 2007

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INTRODUCTION

Based on comments received from the Florida Department of Environmental Protection (FDEP), the "BART Exemption Modeling Analysis for Affected FPL Plants" report submitted in January 2007 has been revised to include updated particulate matter (PM) emissions for four Florida Power and Light Co. (FPL) plants using the maximum PM emissions measured during annual stack tests performed from 2001 to 2003. Supportive stack test data and maximum heat input rates used for the FPL plants are presented in Appendices B and C Based on the updated PM emissions, regional haze modeling was performed, which demonstrated that the maximum visibility impairment values for each plant are still predicted to be less than FDEP's Best Available Retrofit Technology (BART) exemption criteria of 0.5 deciview (dv). Therefore, exemptions from BART determination are requested for each of the FPL power plants addressed in this report.

Pursuant to Section 403.061(35), Florida Statutes, the Federal Clean Air Act, and the regional haze regulations contained in Title 40, Part 51 of the Code of Federal Regulations (40 CFR 51), Subpart P – Protection of Visibility, the FDEP is required to ensure that certain sources of visibility impairing pollutants in Florida use BART to reduce the impact of their emissions on regional haze in federal Class I areas Requirements for individual source BART control technology determinations and for BART exemptions are in Rule 62-296.340 of the Florida Administrative Code (F.A.C.).

Rule 62-296.340(5)(c), F.A.C., states that a BART eligible source may demonstrate that it is exempt from the requirement for BART determination for all pollutants by performing an individual source attribution analysis in accordance with the procedures contained in 40 CFR 51, Appendix Y. A BART-eligible source is exempt from BART determination requirements if its contribution to visibility impairment, as determined below, does not exceed 0.5 dv above natural conditions in any Class I area.

For electric generating units subject to the Clean Air Interstate Rule (CAIR) program, the source attribution analysis need only consider PM emissions (including primary sulfate) for comparison with the contribution threshold.

The 98th percentile, i.e., the 8th highest 24-hour average visibility impairment value in any year or the 22nd highest 24-hour average visibility impairment value over 3 years combined, whichever is higher, is compared to 0.5 dv in the source attribution analysis

Based on Rule 62-296 340(5)(c), F.A.C , if the owner or operator of a BART-eligible source requests exemption from the requirement for BART determination for all pollutants by submitting its source attribution analysis to the FDEP by January 31, 2007, and the FDEP ultimately grants such exemption, the requirement for submission of an air construction permit application pursuant to 62-296 340(3)(b)1, F.A C., shall not apply.

This report is submitted to the FDEP to present the source attribution analysis for the following BART-eligible emissions units at the FPL power plants that are BART-eligible sources:

- Cape Canaveral Power Plant - Unit No 1, Unit No. 2;
- Port Everglades Power Plant - Unit No. 3, Unit No. 4;
- Manatee Power Plant - Unit No. 1, Unit No. 2;
- Martin Power Plant - Unit No. 1,Unit No 2; and
- Riviera Power Plant - Unit No. 4.

This report contains the following five sections that present a brief source description, visibility modeling methodology, and visibility modeling analysis results for each of the power plants:

- Section A - Cape Canaveral Power Plant;
- Section B - Port Everglades Power Plant;
- Section C - Manatee Power Plant;
- Section D - Martin Power Plant; and
- Section E - Riviera Power Plant.

The objective of the analysis is to demonstrate that these emissions units are exempt from BART determination.

It should be noted that the Turkey Point Power Plant has two BART-eligible units. Because the visibility impacts for these units were predicted to be greater than 0.5 dv, these units are not exempt from BART determination. As a result, a separate report will be submitted for the plant that includes a BART determination analysis.

The source information and methodologies used for the BART exemption analysis are the same as those presented in the document entitled "Air Modeling Protocol to Evaluate Best Available Retrofit Technology (BART) Options for Affected FPL Plants." A copy of this document has been included for reference in Appendix A. The summaries of the annual PM stack emission tests performed for the

FPL power plants are presented in Appendix B. In addition, the maximum heat input rate used to develop the maximum PM emission rate for the affected units at the Port Everglades Power Plant was obtained from the stack test data. The updated PM emission rates that were modeled in the visibility impairment analysis for the Cape Canaveral, Manatee, Martin, and Riviera Power Plants are presented in Appendix C.

SECTION A- CAPE CANAVERAL POWER PLANT

1.0 SOURCE DESCRIPTION

The Cape Canaveral Power Plant (PCC) consists of two oil-fired and natural gas-fired conventional steam electric generating units, designated as Unit No. 1 and Unit No. 2. Each steam unit is a nominal 400 megawatt (MW) class (electric) steam generator that drives a single reheat turbine generator. Both units are best available retrofit technology (BART)-eligible emission units.

PCC is located on the west side of the Indian River, approximately 8 miles north of Cocoa, Florida on U.S. Highway No. 1, Brevard County. An area map showing PCC and prevention of significant deterioration (PSD) Class I areas located within 300 kilometers (km) of PCC is presented in Figure 1-1 of the Protocol. The PSD Class I areas and their distances from the plant are as follows:

- Chassahowitzka National Wilderness Area (NWA) - 182 km;
- Okefenokee NWA - 270 km; and
- Everglades National Park (NP) - 295 km.

The general location of this plant, in Universal Transverse Mercator (UTM) coordinates, is 523.1 km, East; 3,148.7 km, North; Zone 17.

The stack, operating, and particulate matter (PM) emission data, including PM speciation, for the BART-eligible emissions units are presented in detail in the Protocol in Appendix A. The supportive annual PM stack test data from 2001 to 2003 and updated PM emission data used in the modeling are presented in Appendices B and C, respectively.

Because there are minimal fugitive PM emissions and the plant is more than 50 km from the nearest PSD Class I area, fugitive PM emissions from this station were not addressed in the BART evaluation.

Building downwash effects were not considered in the modeling since the distance of the nearest PSD Class I area is more than 50 km from the plant.

2.0 AIR QUALITY MODELING METHODOLOGY

The California Puff (CALPUFF) model, Version 5.756, was used to predict the maximum visibility impairment at the PSD Class I areas located within 300 km of PCC. Recent technical enhancements, including changes to the over-water boundary layer formulation and coastal effects modules (sponsored by the Minerals Management Service), are included in this version The methods and assumptions used in the CALPUFF model are presented in the Protocol in Appendix A. The 4-km spacing Florida domain was used for the BART exemption. The refined California Meteorology (CALMET) domain used for this modeling analysis has been provided by the Florida Department of Environmental Protection (FDEP). The major features used in preparing these CALMET data have also been described in Section 4.0 of the Protocol.

Currently, the atmospheric light extinction is estimated by an algorithm developed by the Interagency Monitoring of Protected Visual Environments (IMPROVE) committee and adopted by the U.S. Environmental Protection Agency (EPA) under the 1999 Regional Haze Rule (RHR) and referred to in this report as the "1999 IMPROVE algorithm." This algorithm tends to underestimate light extinction for the highest haze conditions and overestimate it for the lowest haze conditions and does not include light extinction due to sea salt, which is important at sites near the seacoasts. As a result of these limitations, the IMPROVE Steering Committee recently developed a new algorithm (the "new IMPROVE algorithm") for estimating light extinction from PM component concentrations, which provides a better correspondence between measured visibility and that calculated from PM component concentrations. A detailed description of the new IMPROVE algorithm and its implementation is presented in Section 3.4 of the Protocol.

The new IMPROVE algorithm will be used if the visibility impairment values predicted with the 1999 IMPROVE algorithm are greater than 0.5 deciview (dv) If the new IMPROVE algorithm is used, the maximum predicted visibility impairment values will be lower than those predicted with the 1999 IMPROVE algorithm.

Visibility impacts were predicted at each PSD Class I area using receptors provided by the National Park Service and are represented in Figures 4-1 through 4-3 of the Protocol.

3.0 AIR QUALITY MODELING METHODOLOGY

Summaries of the updated maximum visibility impairment values for Unit No. 1 and Unit No. 2 at PCC estimated using the 1999 IMPROVE algorithm are presented in Tables A-1 and A-2. The 98th percentile 24-hour average visibility impairment values (i.e., 8th highest) for the years 2001, 2002, and 2003, and the 22nd highest 24-hour average visibility impairment value over the 3 years, are presented in Table A-1. The number of days and receptors for which the visibility impairment was predicted to be greater than 0.5 dv is also presented in Table A-1. The eight highest visibility impairment values predicted for each modeled year at the PSD Class I areas are presented in Table A-2

As shown in Tables A-1 and A-2, the 8th highest visibility impairment values predicted for each year at all of the PSD Class I areas using the 1999 IMPROVE algorithm are less than 0.5 dv. The 22nd highest visibility impairment values predicted over the 3-year period at the PSD Class I areas are also less than 0.5 dv. As discussed previously, if the new IMPROVE algorithm were used, the maximum predicted visibility impairment values would be lower using the new IMPROVE algorithm than those predicted with the 1999 IMPROVE algorithm.

Based on these results, which demonstrate that the maximum visibility impairment values for Unit No 1 and Unit No. 2 are predicted to be less than the FDEP's BART exemption criteria of 0.5 dv, an exemption from BART determination is requested for PCC

The input and output files (excluding CALMET) used for the exemption modeling are provided on a CD submitted with this report Quality assurance procedures were followed, as described in the Protocol, to ensure that the setup and execution of the CALPUFF model and processing of the modeling results satisfy the regulatory objectives of the BART program.

SECTION B- PORT EVERGLADES POWER PLANT

1.0 SOURCE DESCRIPTION

The Port Everglades Power Plant (PPE) consists of four fossil fuel steam generators and 12 simple-cycle combustion turbines. Two of the steam generators, Unit No 3 and Unit No 4, are best available retrofit technology (BART)-eligible emission units Each of these steam units is a nominal 402-megawatt (MW) class (electric) steam generator that fires natural gas and fuel oil

PPE is located at 8100 Eisenhower Boulevard, Fort Lauderdale, Broward County. An area map showing PPE and prevention of significant deterioration (PSD) Class I areas located within 300 kilometers (km) of the plant is presented in Figure 1-1 of the Protocol. The only PSD Class I area located within 300 km of the plant is the Everglades National Park (NP), located about 54 km away.

The general location of this plant, in Universal Transverse Mercator (UTM) coordinates, is 587 4 km, East; 2,885.3 km, North; Zone 17.

The stack, operating and particulate matter (PM) emission data, including PM speciation, for the BART-eligible emissions units are presented in detail in the Protocol provided in Appendix A The supportive annual PM stack test data from 2001 to 2003 that present the maximum heat input rates for each unit are provided in Appendix B. The PM emission rates used in the modeling were based on the permitted PM emission rate and the maximum heat input rate obtained from the stack tests over the 3-year period. As a result, no additional modeling was required based on FDEP's comments.

Because there are minimal fugitive PM emissions and the plant is more than 50 km from the nearest PSD Class I area, fugitive PM emissions from this station were not addressed in the BART evaluation.

Building downwash effects were not considered in the modeling since the distance of the nearest PSD Class I area is more than 50 km from the plant.

2.0 AIR QUALITY MODELING METHODOLOGY

The California Puff (CALPUFF) model, Version 5 756, was used to predict the maximum visibility impairment at the PSD Class I areas located within 300 km of PPE. Recent technical enhancements, including changes to the over-water boundary layer formulation and coastal effects modules (sponsored by the Minerals Management Service), are included in this version. The methods and assumptions used in the CALPUFF model are presented in the Protocol. The 4-km spacing Florida domain was used for the BART exemption The refined CALMET domain used for this modeling analysis has been provided by the Florida Department of Environmental Protection (FDEP) The major features used in preparing these CALMET data have also been described in Section 4.0 of the Protocol in Appendix A.

Currently, the atmospheric light extinction is estimated by an algorithm developed by the Interagency Monitoring of Protected Visual Environments (IMPROVE) committee, which was adopted by the U.S Environmental Protection Agency (EPA) under the 1999 Regional Haze Rule (RHR) and referred to in this report as the "1999 IMPROVE algorithm." This algorithm tends to underestimate light extinction for the highest haze conditions and overestimate it for the lowest haze conditions and does not include light extinction due to sea salt, which is important at sites near the seacoasts As a result of these limitations, the IMPROVE Steering Committee recently developed a new algorithm (the "new IMPROVE algorithm") for estimating light extinction from PM component concentrations, which provides a better correspondence between measured visibility and that calculated from PM component concentrations. A detailed description of the new IMPROVE algorithm and its implementation is presented in Section 3 4 of the Protocol.

The new IMPROVE algorithm will be used if the visibility impairment values predicted with the 1999 IMPROVE algorithm are greater than 0.5 deciview (dv) If the new IMPROVE algorithm is used, the maximum predicted visibility impairment values will be lower than those predicted with the 1999 IMPROVE algorithm.

Visibility impacts were predicted at the PSD Class I area using receptors provided by the National Park Service and are represented in Figure 4-2 of the Protocol.

3.0 AIR QUALITY MODELING METHODOLOGY

Summaries of the maximum visibility impairment values for Unit No 3 and Unit No. 4 at PPE estimated using the 1999 IMPROVE algorithm are presented in Tables B-1 and B-2. The 98th percentile 24-hour average visibility impairment values (i e , 8th highest) for the years 2001, 2002 and 2003, and the 22nd highest 24-hour average visibility impairment value over the 3 years, are presented in Table B-1. The number of days and receptors for which the visibility impairment was predicted to be greater than 0.5 dv is also presented in Table B-1 The eight highest visibility impairment values predicted for each modeled year at the PSD Class I area are presented in Table B-2

As shown in Tables B-1 and B-2, the 8th highest visibility impairment values predicted at the PSD Class I area are 0 59 dv in 2003 while the 22nd highest visibility impairment value predicted over the 3-year period is 0.56 dv. As a result, the visibility impacts were evaluated at the Everglades NP with the new IMPROVE algorithm Similar to the results presented using the 1999 IMPROVE algorithm, summaries of the maximum visibility impairment values estimated using the new IMPROVE algorithm are presented in Tables B-3 and B-4. As shown in Tables B-3 and B-4, the highest 8th highest visibility impairment value predicted at the Everglades NP with the new IMPROVE algorithm is 0 46 dv. The 22nd highest visibility impairment value predicted at this PSD Class I area over the 3-year period is 0.43 dv.

Based on these results, which demonstrate that the maximum visibility impairment values for Unit No. 3 and Unit No 4 are predicted to be less than the FDEP's BART exemption criteria of 0.5 dv, an exemption from BART determination is requested for PPE

The input and output files (excluding CALMET) used for the exemption modeling are provided on a CD submitted with this report Quality assurance procedures were followed, as described in the Protocol, to ensure that the setup and execution of the CALPUFF model and processing of the modeling results satisfy the regulatory objectives of the BART program.

SECTION C- MANATEE POWER PLANT

1.0 SOURCE DESCRIPTION

The Manatee Power Plant (PMT) consists of two oil-fired and natural gas-fired conventional steam electric generating units, designated as Unit No. 1 and Unit No 2, a "4-on-1" gas-fired combined cycle unit (Unit No. 3) and associated support equipment. Each steam unit is a nominal 800-megawatt (MW) class (electric). Both steam units are best available retrofit technology (BART)-eligible emission units.

PMT is located at 19050 State Road 62, Parrish, Manatee County. An area map showing the PMT Plant and prevention of significant deterioration (PSD) Class I areas located within 300 kilometers (km) of the plant is presented in Figure 1-1 of the Protocol. The PSD Class I areas and their distances from the plant are as follows:

- Chassahowitzka National Wilderness Area (NWA) - 116 km; and
- Everglades National Park (NP) - 212 km.

The general location of this plant, in Universal Transverse Mercator (UTM) coordinates, is 367.3 km, East; 3,054.3 km, North; Zone 17.

The stack, operating, and particulate matter (PM) emission data, including PM speciation, for the BART-eligible emissions units are presented in detail in the Protocol in Appendix A. The supportive annual PM stack test data from 2001 to 2003 and updated PM emission data used in the modeling are presented in Appendices B and C, respectively.

Because there are minimal fugitive PM emissions and the plant is more than 50 km from the nearest PSD Class I area, fugitive PM emissions from this station were not addressed in the BART evaluation.

Building downwash effects were not considered in the modeling since the distance of the nearest PSD Class I area is more than 50 km from the plant.

2.0 AIR QUALITY MODELING METHODOLOGY

The California Puff (CALPUFF) model, Version 5 756, was used to predict the maximum visibility impairment at the PSD Class I areas located within 300 km of PMT. Recent technical enhancements, including changes to the over-water boundary layer formulation and coastal effects modules (sponsored by the Minerals Management Service), are included in this version. The methods and assumptions used in the CALPUFF model are presented in the Protocol The 4-km spacing Florida domain was used for the BART exemption. The refined CALMET domain used for this modeling analysis has been provided by the Florida Department of Environmental Protection (FDEP). The major features used in preparing these CALMET data have also been described in Section 4 0 of the Protocol.

Currently, the atmospheric light extinction is estimated by an algorithm developed by the Interagency Monitoring of Protected Visual Environments (IMPROVE) committee, which was adopted by the EPA under the 1999 Regional Haze Rule (RHR) and referred to in this report as the "1999 IMPROVE algorithm" This algorithm tends to underestimate light extinction for the highest haze conditions and overestimate it for the lowest haze conditions and does not include light extinction due to sea salt, which is important at sites near the seacoasts. As a result of these limitations, the IMPROVE Steering Committee recently developed a new algorithm (the "new IMPROVE algorithm") for estimating light extinction from PM component concentrations, which provides a better correspondence between measured visibility and that calculated from PM component concentrations. A detailed description of the new IMPROVE algorithm and its implementation is presented in Section 3 4 of the Protocol.

The new IMPROVE algorithm will be used if the visibility impairment values predicted with the 1999 IMPROVE algorithm are greater than 0.5 deciview (dv). If the new IMPROVE algorithm is used, the maximum predicted visibility impairment values will be lower than those predicted with the 1999 IMPROVE algorithm.

Visibility impacts were predicted at each PSD Class I area using receptors provided by the National Park Service and are represented in Figures 4-1 through 4-2 of the Protocol

3.0 AIR QUALITY MODELING METHODOLOGY

Summaries of the updated maximum visibility impairment values for Unit No. 1 and Unit No 2 at PMT estimated using the 1999 IMPROVE algorithm are presented in Tables C-1 and C-2. The 98th percentile 24-hour average visibility impairment values (i.e., 8th highest) for the years 2001, 2002, and 2003, and the 22nd highest 24-hour average visibility impairment value over the 3 years, are presented in Table C-1. The number of days and receptors for which the visibility impairment was predicted to be greater than 0.5 dv is also presented in Table C-1. The eight highest visibility impairment values predicted for each modeled year at the PSD Class I areas are presented in Table C-2

As shown in Tables C-1 and C-2, the 8th highest visibility impairment values predicted for each year at all of the PSD Class I areas using the 1999 IMPROVE algorithm are less than 0.5 dv. The 22nd highest visibility impairment values predicted over the 3-year period at the PSD Class I areas are also less than 0.5 dv As discussed previously, if the new IMPROVE algorithm were used, the maximum predicted visibility impairment values would be lower using the new IMPROVE algorithm than those predicted with the 1999 IMPROVE algorithm.

Based on these results, which demonstrate that the maximum visibility impairment values for Unit No. 1 and Unit No. 2 are predicted to be less than the FDEP's BART exemption criteria of 0.5 dv, an exemption from BART determination is requested for PMT.

The input and output files (excluding CALMET) used for the exemption modeling are provided on a CD submitted with this report Quality assurance procedures were followed, as described in the Protocol, to ensure that the setup and execution of the CALPUFF model and processing of the modeling results satisfy the regulatory objectives of the BART program

SECTION D- MARTIN POWER PLANT

1.0 SOURCE DESCRIPTION

The Martin Power Plant (PMR) consists of two oil-fired and natural gas-fired conventional steam-electric generating units, designated as Unit No. 1 and Unit No 2; combined cycle units (Units 3A, 3B, 4A, and 4B) consisting of 170 megawatt (MW) gas turbines matched with heat recovery steam generators (HRSGs) [each pair of gas turbines (3A/3B and 4A/4B) provides steam to a common steam-electrical turbine (160 MW each)]; and two simple cycle gas turbines (Units 8A and 8B), each rated at 170 MW.

Each steam unit is a nominal 863 MW class (electric). Both steam units are best available retrofit technology (BART)-eligible emission units.

PMR is located approximately 7 miles north of Indiantown on State Road 710 and east of Lake Okeechobee in Martin County, Florida. An area map showing PMR and prevention of significant deterioration (PSD) Class I areas located within 300 kilometers (km) of the plant is presented in Figure 1-1 of the Protocol. The PSD Class I areas and their distances from the plant are as follows:

- Chassahowitzka National Wilderness Area (NWA) - 145 km; and
- Everglades National Park (NP) - 267 km

The general location of this plant, in Universal Transverse Mercator (UTM) coordinates, is 543.1 km, East; 2,993.0 km, North; Zone 17.

The stack, operating and particulate matter (PM) emission data, including PM speciation, for the BART-eligible emissions units are presented in detail in the Protocol in Appendix A. The supportive annual PM stack test data from 2001 to 2003 and updated PM emission data used in the modeling are presented in Appendices B and C, respectively.

Because there are minimal fugitive PM emissions and the plant is more than 50 km from the nearest PSD Class I area, fugitive PM emissions from this station were not addressed in the BART evaluation.

Building downwash effects were not considered in the modeling since the distance of the nearest PSD Class I area is more than 50 km from the plant.

2.0 AIR QUALITY MODELING METHODOLOGY

The California Puff (CALPUFF) model, Version 5.756, was used to predict the maximum visibility impairment at the PSD Class I areas located within 300 km of PMR. Recent technical enhancements, including changes to the over-water boundary layer formulation and coastal effects modules (sponsored by the Minerals Management Service), are included in this version. The methods and assumptions used in the CALPUFF model are presented in the Protocol. The 4-km spacing Florida domain was used for the BART exemption The refined CALMET domain used for this modeling analysis has been provided by the Florida Department of Environmental Protection (FDEP) The major features used in preparing these CALMET data have also been described in Section 4 0 of the Protocol

Currently, the atmospheric light extinction is estimated by an algorithm developed by the Interagency Monitoring of Protected Visual Environments (IMPROVE) committee, which was adopted by the U.S. Environmental Protection Agency (EPA) under the 1999 Regional Haze Rule (RHR) and referred to in this report as the "1999 IMPROVE algorithm. " This algorithm tends to underestimate light extinction for the highest haze conditions and overestimate it for the lowest haze conditions and does not include light extinction due to sea salt, which is important at sites near the seacoasts. As a result of these limitations, the IMPROVE Steering Committee recently developed a new algorithm (the "new IMPROVE algorithm") for estimating light extinction from PM component concentrations, which provides a better correspondence between measured visibility and that calculated from PM component concentrations A detailed description of the new IMPROVE algorithm and its implementation is presented in Section 3 4 of the Protocol

The new IMPROVE algorithm will be used if the visibility impairment values predicted with the 1999 IMPROVE algorithm are greater than 0 5 deciview (dv) If the new IMPROVE algorithm is used, the maximum predicted visibility impairment values will be lower than those predicted with the 1999 IMPROVE algorithm

Visibility impacts were predicted at each PSD Class I area using receptors provided by the National Park Service and are represented in Figures 4-1 through 4-2 of the Protocol.

3.0 AIR QUALITY MODELING METHODOLOGY

Summaries of the updated maximum visibility impairment values for Unit No. 1 and Unit No. 2 at PMR estimated using the 1999 IMPROVE algorithm are presented in Tables D-1 and D-2. The 98th percentile 24-hour average visibility impairment values (i.e., 8th highest) for the years 2001, 2002, and 2003, and the 22nd highest 24-hour average visibility impairment value over the 3 years, are presented in Table D-1. The number of days and receptors for which the visibility impairment was predicted to be greater than 0.5 dv is also presented in Table D-1. The eight highest visibility impairment values predicted for each modeled year at the PSD Class I areas are presented in Table D-2.

As shown in Tables D-1 and D-2, the 8th highest visibility impairment values predicted for each year at all of the PSD Class I areas using the 1999 IMPROVE algorithm are less than 0.5 dv. The 22nd highest visibility impairment values predicted over the 3-year period at the PSD Class I areas are also less than 0.5 dv As discussed previously, if the new IMPROVE algorithm were used, the maximum predicted visibility impairment values would be lower using the new IMPROVE algorithm than those predicted with the 1999 IMPROVE algorithm

Based on these results, which demonstrate that the maximum visibility impairment values for Unit No. 1 and Unit No. 2 are predicted to be less than the FDEP's BART exemption criteria of 0 5 dv, an exemption from BART determination is requested for PMR

The input and output files (excluding CALMET) used for the exemption modeling are provided on a CD submitted with this report. Quality assurance procedures were followed, as described in the Protocol, to ensure that the setup and execution of the CALPUFF model and processing of the modeling results satisfy the regulatory objectives of the BART program

SECTION E- RIVIERA BEACH POWER PLANT

1.0 SOURCE DESCRIPTION

The Riviera Beach Power Plant (PRV) consists of two oil-fired and natural gas-fired conventional steam electric generating units, designated as Unit No. 3 and Unit No 4 Each steam unit is a nominal 300 megawatt (MW) class (electric). Unit No 4 is a best available retrofit technology (BART)-eligible emission unit; Unit No. 3 is not.

PRV is located at 200-300 Broadway, Riviera Beach, Palm Beach County An area map showing the PRV Plant and prevention of significant deterioration (PSD) Class I areas located within 300 kilometers (km) of the plant is presented in Figure 1-1 of the Protocol The only PSD Class I area located within 300 km of the plant is the Everglades National Park (NP), located about 122 km away.

The general location of this plant, in Universal Transverse Mercator (UTM) coordinates, is 594.2 km, East; 2,960.7 km, North; Zone 17.

The stack, operating and particulate matter (PM) emission data, including PM speciation, for the BART-eligible emissions units are presented in detail in the Protocol in Appendix A The supportive annual PM stack test data from 2001 to 2003 and updated PM emission data used in the modeling are presented in Appendices B and C, respectively

Because there are minimal fugitive PM emissions and the plant is more than 50 km from the nearest PSD Class I area, fugitive PM emissions from this station were not addressed in the BART evaluation.

Building downwash effects were not considered in the modeling since the distance of the nearest PSD Class I area is more than 50 km from the plant

2.0 AIR QUALITY MODELING METHODOLOGY

The California Puff (CALPUFF) model, Version 5.756, was used to predict the maximum visibility impairment at the PSD Class I areas located within 300 km of PRV. Recent technical enhancements, including changes to the over-water boundary layer formulation and coastal effects modules (sponsored by the Minerals Management Service), are included in this version. The methods and assumptions used in the CALPUFF model are presented in the Protocol. The 4-km spacing Florida domain was used for the BART exemption. The refined CALMET domain used for this modeling analysis has been provided by the Florida Department of Environmental Protection (FDEP). The major features used in preparing these CALMET data have also been described in Section 4.0 of the Protocol.

Currently, the atmospheric light extinction is estimated by an algorithm developed by the Interagency Monitoring of Protected Visual Environments (IMPROVE) committee, which was adopted by the U.S. Environmental Protection Agency (EPA) under the 1999 Regional Haze Rule (RHR) and referred to in this report as the "1999 IMPROVE algorithm." This algorithm tends to underestimate light extinction for the highest haze conditions and overestimate it for the lowest haze conditions and does not include light extinction due to sea salt, which is important at sites near the seacoasts. As a result of these limitations, the IMPROVE Steering Committee recently developed a new algorithm (the "new IMPROVE algorithm") for estimating light extinction from PM component concentrations, which provides a better correspondence between measured visibility and that calculated from PM component concentrations. A detailed description of the new IMPROVE algorithm and its implementation is presented in Section 3.4 of the Protocol.

The new IMPROVE algorithm will be used if the visibility impairment values predicted with the 1999 IMPROVE algorithm are greater than 0.5 deciview (dv). If the new IMPROVE algorithm is used, the maximum predicted visibility impairment values will be lower than those predicted with the 1999 IMPROVE algorithm.

Visibility impacts were predicted at the PSD Class I area using receptors provided by the National Park Service and are represented in Figure 4-2 of the Protocol.

3.0 AIR QUALITY MODELING METHODOLOGY

Summaries of the updated maximum visibility impairment values for Unit No 4 at PRV estimated using the 1999 IMPROVE algorithm are presented in Tables E-1 and E-2. The 98th percentile 24-hour average visibility impairment values (i.e., 8th highest) for the years 2001, 2002 and 2003, and the 22nd highest 24-hour average visibility impairment value over the 3 years, are presented in Table E-1. The number of days and receptors for which the visibility impairment was predicted to be greater than 0.5 dv is also presented in Table E-1. The eight highest visibility impairment values predicted for each modeled year at the PSD Class I area are presented in Table E-2

As shown in Tables E-1 and E-2, the 8th highest visibility impairment values predicted for each year at all of the PSD Class I areas using the 1999 IMPROVE algorithm are less than 0.5 dv. The 22nd highest visibility impairment value predicted over the 3-year period at the PSD Class I area is also less than 0.5 dv. As discussed previously, if the new IMPROVE algorithm were used, the maximum predicted visibility impairment values would be lower using the new IMPROVE algorithm than those predicted with the 1999 IMPROVE algorithm

Based on these results, which demonstrate that the maximum visibility impairment values for Unit No. 4 are predicted to be less than the FDEP's BART exemption criteria of 0.5 dv, an exemption from BART determination is requested for PRV Unit No 4

The input and output files (excluding CALMET) used for the exemption modeling are provided on a CD submitted with this report. Quality assurance procedures were followed, as described in the Protocol, to ensure that the setup and execution of the CALPUFF model and processing of the modeling results satisfy the regulatory objectives of the BART program.

FDEP Reasonable Further Progress Workshop
Slide 1

Proposed Reasonable Progress Rule Workshop

Brief Background and Procedure
Public Workshop
June 14, 2007

FDEP Reasonable Further Progress Workshop
Slide 2

Regulatory Requirements

- Clean Air Act – Sections 169A and B
- Federal Rules –
  - Federal Register, Vol. 64, No. 126, Thursday, July 1, 1999 – "Regional Haze Rule"
  - 40 CFR Part 51, Subpart P – Protection of Visibility
- Federal Guidance on Reasonable Progress
  - Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program, U.S. EPA, June 1, 2007, rev

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Slide 3

National Goal

- "Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution."
- Achieve natural visibility conditions within Class I areas by 2064

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Slide 4

Regional Haze Rule - Purpose

- Section 51.300 – ". . . require states to develop programs to assure reasonable progress toward meeting the national goal of preventing any future, and remedying any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution ..."

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RH Program Requirements

- State must submit an implementation plan (SIP)
  - Must establish goals (expressed in deciviews) that provide for **reasonable progress** towards achieving natural visibility conditions

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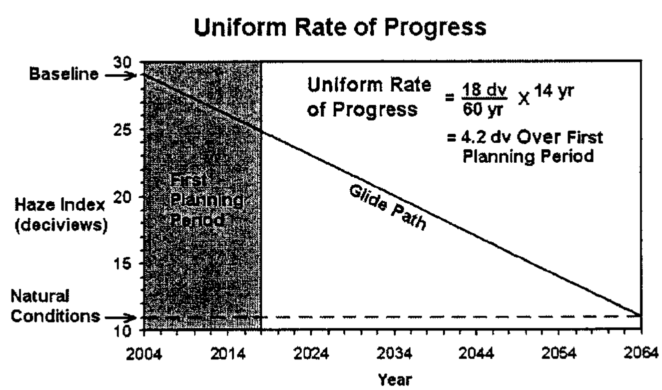
Slide 6

Concept



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Four Factors in Determining the Reasonable Progress Goal

- Cost of compliance
- Time necessary for compliance
- Energy and non-air quality environmental impacts of compliance
- Remaining useful life of any potentially affected sources

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Three Components to Consider

- Evaluation of 2018 visibility considering current or "on the books" requirements for emissions reductions (e.g., CAIR, motor vehicle emissions standards, and many other already commanded reductions). VISTAS has completed this component.
- Regional Haze Rule directed **BART** requirements, section 51.302. Not completed.
- Regional Haze Rule directed **Reasonable Progress** requirement, section 51.308. Subject of this rulemaking.

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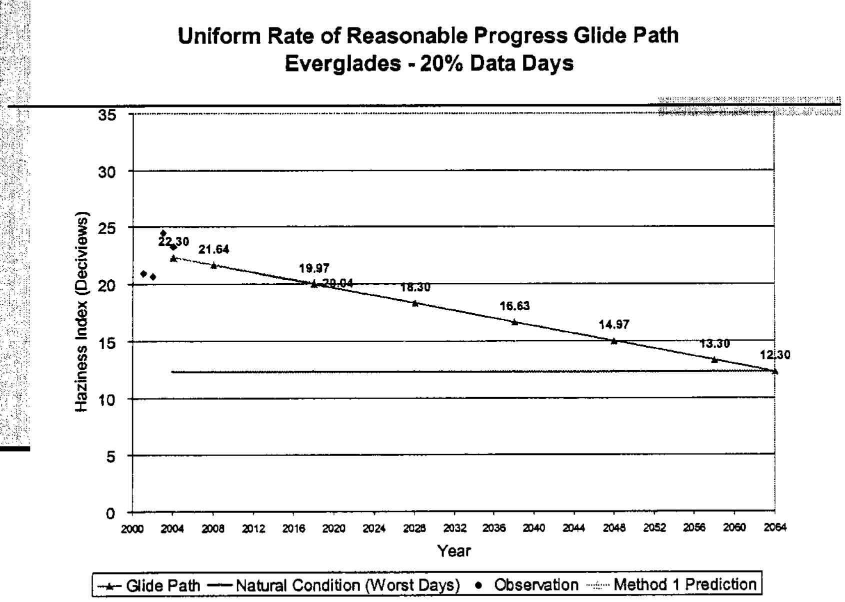

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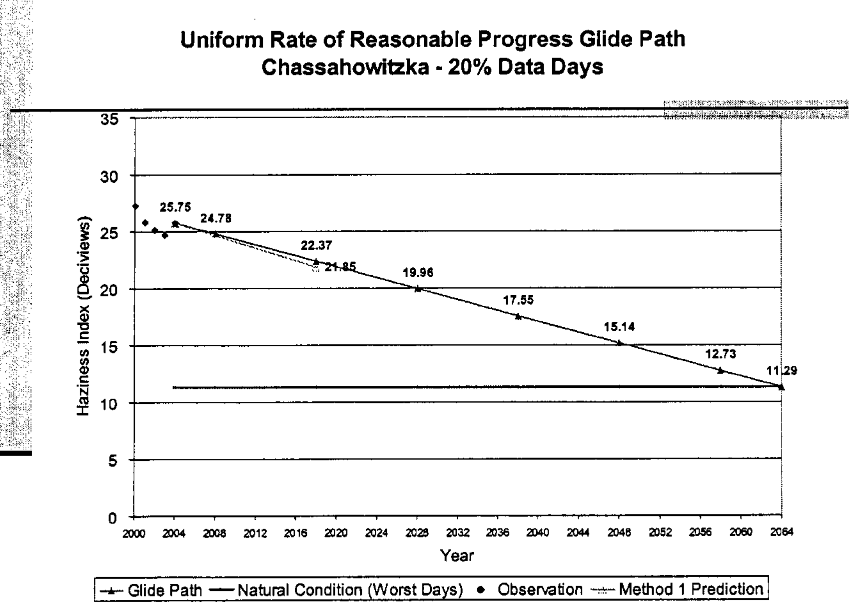

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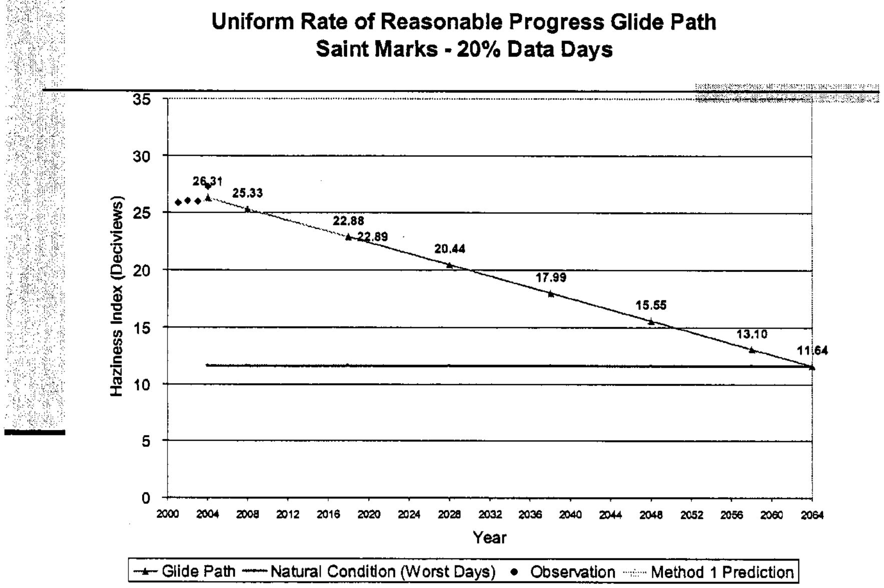

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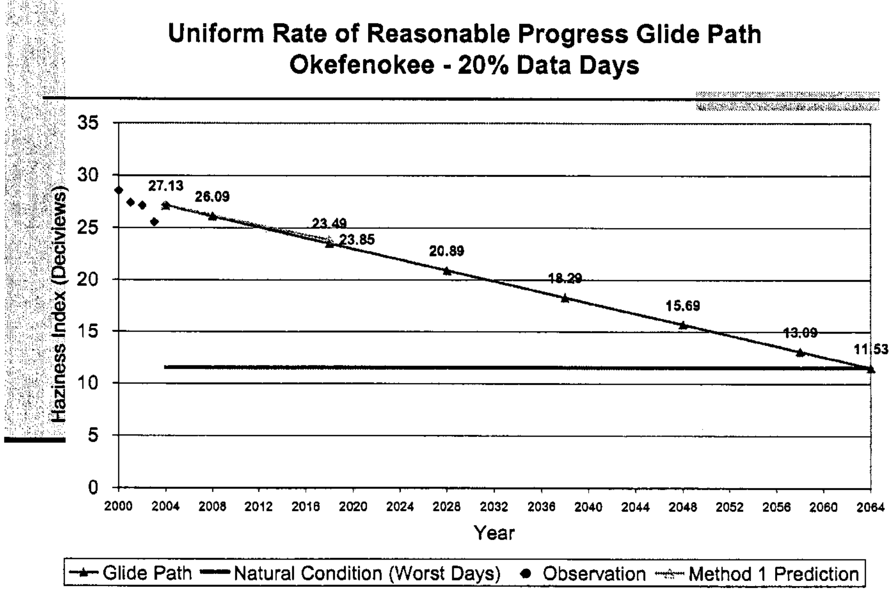

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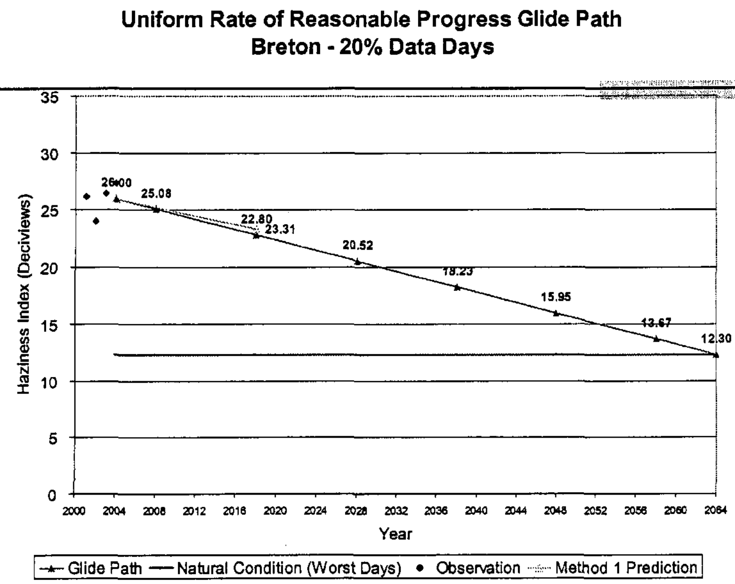

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IPM Projections

- Converts all oil-fired boilers to gas
- Affects sources throughout the state, but largely in South Florida.
- Primary power company (FPL) has indicated no intention of gas-only operation.
- Result, projected glidepaths (esp. Everglades) overly optimistic.

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Plant Name	Point ID	2002 Actual SO2 Emissions (TPY)	2018 VISTAS Projected SO2 Emissions (TPY)
FLORIDA POWER & LIGHT (PPE) PORT EVERGLA	1	3,053	0
	2	3,264	0
	3	6,409	0
	4	6,205	0
FLORIDA POWER & LIGHT (PTF) TURKEY POINT	1	4,327	0
	2	4,610	0
FLORIDA POWER & LIGHT (PMT) MANATEE POWE	1	13,930	0
	2	15,073	0
FLORIDA POWER & LIGHT (PMR) FPL / MARTIN	1	6,886	0
	2	7,603	0
FLORIDA POWER & LIGHT (PRV) RIVIERA POWE	3	4,630	0
	4	4,291	0
PROGRESS ENERGY FLORIDA, INC. ANCLOTE PO	1	13,879	0
	2	13,225	0
PROGRESS ENERGY FLORIDA, INC. BARTOW PLA	1	6,149	0
	2	6,463	0
	3	11,249	0
NORTHSIDE	3	7,146	0
PROGRESS ENERGY FLORIDA, INC. FL POWER S	1	657	0
	2	809	0
	3	740	0

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Applicability of Reasonable Progress

- Applies to all sources and all visibility-impairing pollutants.
- Purpose of this rule is to use the information derived from VISTAS to target the most relevant sources (i.e., pair-down the number of sources and pollutants needed to evaluate for reasonable progress).

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Important Results from VISTAS

- Sulfate is the dominate component of regional haze in the Southeast.
  - Implication – focus on SO2 reductions
- Nearly all of the SO2 emissions are from coal and oil-fired EGU's, and industrial plants.
  - Implication – focus on point source EGUs' and industrial facilities.

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Important Product Produced by VISTAS -- Area of Influence

- VISTAS developed information based on wind trajectories that indicate the likelihood that a source at a given location will impact each Class I area.
- A value (RTmax) is determined for each source location that is proportional to each sources probability that it would impact a particular Class I area on days of poor visibility.

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Proposed Selection Criteria

- Selection based on modified Georgia criteria with RTmax*Q/d:
  - VISTAS residence time data (within 5% for EGU's and 10% non-EGU's)
  - 2002 actual emissions (units > 250 tpy)
  - >= 0.5% unit contribution, considering only Florida units
- Selection based on each Class I area potentially affected by Florida sources (EVER,CHAS,SAMA,OKEF,WOLF,BRET)

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Explanation of Terms

- RTmax -- This term is a metric for the frequency that air flows from the source to the Class I area on days of poor visibility.
- Q – Actual 2002 SO2 emissions in tons per year
- d – Distance (km), this term is a surrogate for dispersion.

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Procedure

- For each unit with SO_2 emissions >=250 tpy, identify all EGU's with an RTmax >=5% and all non-EGU's with an RTmax>=10% for each Class I area.
- For each of these units, calculate RTmax*Q/d for each Class I area.
- For each Class I area, sum RTmax*Q/d over all units and calculate the relative contribution for each unit.
- Select all units that contribute 0.5% or greater.

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Proposed Selection (see handouts)

- 30 Facilities comprising 69 units
  - 17 power plants
  - 4 pulp and paper
  - 9 other (chemical, phosphate,etc.)

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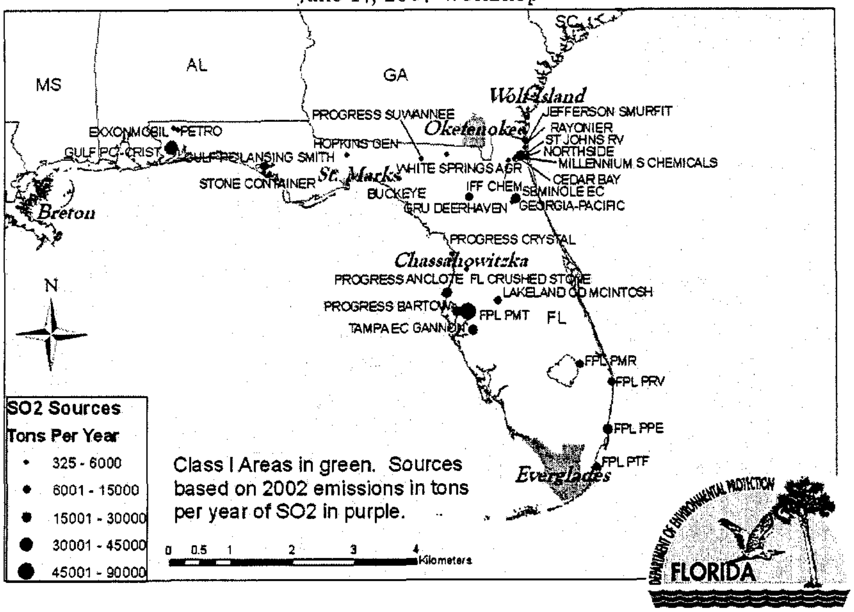
Proposed Reasonable Progress Sources

June 14, 2007 Workshop



FLORIDA ADMINISTRATIVE WEEKLY UNDER SECTION VI, "NOTICES OF MEETINGS, WORKSHOPS AND PUBLIC HEARINGS."

THE PRELIMINARY TEXT OF THE PROPOSED RULE DEVELOPMENT IS NOT AVAILABLE.

DEPARTMENT OF ENVIRONMENTAL PROTECTION

Notices for the Department of Environmental Protection between December 28, 2001 and June 30, 2006, go to http://www.dep.state.fl.us/ under the link or button titled "Official Notices."

DEPARTMENT OF ENVIRONMENTAL PROTECTION

RULE NO.:	RULE TITLE:
62-296.341	Regional Haze – Reasonable Progress

PURPOSE AND EFFECT: The proposed rule development involves amendments to rule Chapter 62-296, F.A.C., to implement the reasonable progress portion of the U.S. Environmental Protection Agency's (EPA's) regional haze regulations. Pursuant to these regulations, the department is required to ensure that certain sources of visibility-impairing pollutants in Florida limit their emissions such that reasonable progress is made toward the goal of achieving natural visibility conditions in federal Class I areas. New Rule 62-296.341, F.A.C., is created to set forth procedural requirements by which reasonable progress determinations will be made for affected sources. There is no draft rule language available at this time; however, it is expected the department will post draft rule language at the following web site by June 6, 2007: http://www.dep.state.fl.us/Air/rules/regulatory.htm.

SUBJECT AREA TO BE ADDRESSED: The proposed new rule section addresses air permitting and control technology requirements for sources subject to the reasonable progress portion of EPA's regional haze regulations.

SPECIFIC AUTHORITY: 403.061 FS.

LAW IMPLEMENTED: 403.031, 403.061, 403.087 FS.

A RULE DEVELOPMENT WORKSHOP WILL BE HELD AT THE DATE, TIME AND PLACE SHOWN BELOW:

DATE AND TIME: Thursday, June 14, 2007, 10:00 a.m.

PLACE: Department of Environmental Protection, Bob Martinez Center, Room 609, 2600 Blair Stone Rd., Tallahassee, Florida

Pursuant to the provisions of the Americans with Disabilities Act, any person requiring special accommodations to participate in this workshop/meeting is asked to advise the agency at least 48 hours before the workshop/meeting by contacting: Ms. Lynn Scearce, (850)921-9551. If you are hearing or speech impaired, please contact the agency using the Florida Relay Service, 1(800)955-8771 (TDD) or 1(800)955-8770 (Voice).

THE PERSON TO BE CONTACTED REGARDING THE PROPOSED RULE DEVELOPMENT AND A COPY OF THE PRELIMINARY DRAFT, IF AVAILABLE, IS: Mr. Tom Rogers, (850)921-9554 or tom.rogers@dep.state.fl.us

THE PRELIMINARY TEXT OF THE PROPOSED RULE DEVELOPMENT IS NOT AVAILABLE.

DEPARTMENT OF ENVIRONMENTAL PROTECTION

RULE NO.:	RULE TITLE:
62-347.100	Purpose

PURPOSE AND EFFECT: The Department, in coordination with the water management districts, proposes to develop a new Chapter 62-347, F.A.C., to develop updated stormwater quality treatment design and performance standards. These design and performance standards will update the existing criteria and reflect new research on design and performance standards, and particularly today's understanding of the impact of nutrient discharges from surface water management systems on water quality. The goal of the rule is to provide stormwater quality treatment design and performance standards that can be applied state-wide. The proposed rule will apply to new systems.

SUBJECT AREA TO BE ADDRESSED: Develop updated stormwater quality treatment design and performance standards for surface water management systems, with particular emphasis on standards that will reduce nutrient discharges.

SPECIFIC AUTHORITY: 373.026(7), 373.043, 373.418, 403.805(1) FS.

LAW IMPLEMENTED: 373.042, 373.409, 373.413, 373.4142, 373.4145, 373.416, 373.4132, 373.426, 373.429 FS.

IF REQUESTED IN WRITING AND NOT DEEMED UNNECESSARY BY THE AGENCY HEAD, A RULE DEVELOPMENT WORKSHOP WILL BE NOTICED IN THE NEXT AVAILABLE FLORIDA ADMINISTRATIVE WEEKLY.

THE PERSON TO BE CONTACTED REGARDING THE PROPOSED RULE DEVELOPMENT AND A COPY OF THE PRELIMINARY DRAFT, IF AVAILABLE, IS: Alice Heathcock, Florida Department of Environmental Protection, Office of Submerged Lands and Environmental Resources, MS 2500, 2600 Blair Stone Road, Tallahassee, FL 32399-2400, telephone (850)245-8483, or e-mail: Alice.Heathcock@dep.state.fl.us. Further information and updates on this proposed rule also may be obtained from the Department's Web Site at: http://www.dep.state.fl.us/water/wetlands/erp/rules/rulestat.htm. (OGC No. 07-0552)

THE PRELIMINARY TEXT OF THE PROPOSED RULE DEVELOPMENT IS NOT AVAILABLE.

Table C1
FDEP Screening Results for Four-Factor Eligibility

Workshop Draft 6-12-07 - Proposed Sources Subject to Reasonable Progress Four-Factor Analysis

Plant ID	Plant Name	Point ID	2002 Actual SO2 Emissions (TPY)	2018 VISTAS Projected SO2 Emissions (TPY)	SO2 BART Determination	Affected Class I Area(s)
0010006	CITY OF GAINESVILLE, GRU DEERHAVEN GENER	5	6,969	1,062		CHAS,OKEF,SAMA,WOLF
0050009	STONE CONTAINER CORPORATION	1	714	744		SAMA
		15	629	735		SAMA
		16	1,871	2,108		SAMA
		19	687	804		SAMA
0050014	GULF POWER COMPANY LANSING SMITH PLANT	1	6,564	7,351		BRET,SAMA
		2	6,742	8,412		BRET,SAMA
0110036	FLORIDA POWER & LIGHT (PPE) PORT EVERGLA	1	3,053	0		EVER
		2	3,284	0		EVER
		3	6,409	0		EVER
		4	6,205	0		EVER
0170004	PROGRESS ENERGY FLORIDA, INC. CRYSTAL RI	1	18,998	13,536		CHAS,OKEF,SAMA
		2	20,728	15,240		CHAS,OKEF,SAMA
		3	26,436	3,634		CHAS,OKEF,SAMA
		4	24,635	6,119		CHAS,OKEF,SAMA
0250003	FLORIDA POWER & LIGHT (PTF) TURKEY POINT	1	4,327	0		EVER
		2	4,610	0		EVER
0310039	MILLENNIUM SPECIALTY CHEMICALS	6	505	590		OKEF,WOLF
0310045-A	SAINT JOHNS RIVER	16	11,076	5,882		OKEF,SAMA,WOLF
		17	10,185	7,420		OKEF,SAMA,WOLF
0310045-B	NORTHSIDE	26	2,421	2,830		OKEF,WOLF
		27	5,090	5,950		OKEF,SAMA,WOLF
		3	7,146	0		OKEF,SAMA,WOLF
0310071	IFF CHEMICAL HOLDINGS, INC.	3	624	733		OKEF,WOLF
0310337	CEDAR BAY COGENERATION INC.	1	650	742		OKEF,WOLF
		2	641	742		OKEF,WOLF
		3	628	742		OKEF,WOLF
0330045	GULF POWER COMPANY CRIST ELECTRIC GENERA	4	2,464	304		BRET
		5	2,711	277		BRET
		6	10,889	1,242		BRET,SAMA
		7	21,546	4,648		BRET,SAMA
0470002	WHITE SPRINGS AGRICULTURAL CHEMICALS,INC	66	1,140	1,496	Yes	OKEF,SAMA
		67	996	1,308	Yes	OKEF
0530021	FLORIDA CRUSHED STONE CO., INC.	18	2,906	2,884		CHAS,SAMA
0570040	TAMPA ELECTRIC COMPANY F.J. GANNON STATI	1	5,157	0		EVER
		2	4,942	0		EVER
		3	5,602	0		EVER
		4	5,577	0		EVER
		5	8,043	0		EVER,SAMA
		6	16,097	0		CHAS,EVER,SAMA
0730003	CITY OF TALLAHASSEE ARVAH B.HOPKINS GENE	4	325	0		SAMA
0810010	FLORIDA POWER & LIGHT (PMT) MANATEE POWE	1	13,930	0		EVER,SAMA
		2	15,073	0		EVER,SAMA
0850001	FLORIDA POWER & LIGHT (PMR) FPL / MARTIN	1	6,886	0		EVER
		2	7,603	0		EVER
0890003	JEFFERSON SMURFIT CORPORATION (US)	15	3,242	3,639		OKEF,WOLF
		6	257	300		WOLF
0890004	RAYONIER PERFORMANCE FIBERS LLC	6	1,075	1,256		OKEF,WOLF
0990042	FLORIDA POWER & LIGHT (PRV) RIVIERA POWE	3	4,630	0		EVER
		4	4,291	0		EVER
1010017	PROGRESS ENERGY FLORIDA, INC. ANCLOTE PO	1	13,879	0		CHAS,EVER,SAMA
		2	13,225	0		CHAS,EVER,SAMA
1030011	PROGRESS ENERGY FLORIDA, INC. BARTOW PLA	1	6,149	0		EVER,SAMA
		2	6,483	0		EVER,SAMA
		3	11,249	0		EVER,SAMA
1050004	LAKELAND ELECTRIC C.D. MCINTOSH, JR. POW	6	6,994	3,842		EVER
1070005	GEORGIA-PACIFIC CORP. PULP/PAPER MILL	15	3,703	4,329		OKEF,WOLF
1070025	SEMINOLE ELECTRIC COOPERATIVE, INC.	1	10,912	6,779		CHAS,OKEF,SAMA,WOLF
		2	12,775	6,508		CHAS,OKEF,SAMA,WOLF
1130005	EXXONMOBIL PRODUCTION COMPANY	34	1,789	1,705		BRET
1130014	PETRO OPERATING COMPANY	10	417	453		BRET
1210003	PROGRESS ENERGY FLORIDA, INC. FL POWER S	1	657	0		SAMA
		2	809	0		SAMA
		3	740	0		SAMA
1230001	BUCKEYE FLORIDA, LIMITED PARTNERSHIP	11	385	450		SAMA
		2	449	524		SAMA
		4	736	860		SAMA
		6	554	647		SAMA
		7	621	726		SAMA

June 1, 2007
rev

Guidance for Setting Reasonable Progress Goals Under the Regional Haze Program

U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Air Quality Policy Division
Geographic Strategies Group
Research Triangle Park, NC

TABLE OF CONTENTS

Abbreviations and Acronyms

BACT - Best Available Control Technology

BART - Best Available Retrofit Technology

CAA - Clean Air Act

CAIR - Clean Air Interstate Rule

CFR - Code of Federal Regulations

dv - Deciviews

EPA - Environmental Protection Agency

FLM - Federal Land Manager

FR - Federal Register

NOx - A mixture of nitrogen dioxide (NO_2), nitric oxide (NO), and other nitrogen oxide gases

NAAQS - National Ambient Air Quality Standard

OAQPS - Office of Air Quality Planning and Standards

$PM_{2.5}$ - Particulate Matter of 2.5 microns or less in size

RHR - Regional Haze Rule

RPG - Reasonable Progress Goal

RPO - Regional Planning Organization

SIP - State Implementation Plan

yr - Year

1.0 INTRODUCTION

The purpose of this document is to provide guidance to States in setting reasonable progress goals (RPGs) as part of their regional haze state implementation plans (SIPs) and in deciding those measures necessary to meet these goals. We emphasize that this document is merely guidance and that States or the Environmental Protection Agency (EPA) may elect to follow or deviate from this guidance, as appropriate. The ultimate determination of whether a given SIP submission by a State meets the statutory requirements of sections 169A and 169B of the Clean Air Act (CAA) and the regional haze regulations at 40 CFR 51.300 - 309 will be accomplished through notice and comment rulemaking in which the facts and circumstances of each State submission will be evaluated by EPA.

Under the Tribal Authority Rule, 40 CFR part 49, Tribes have the authority to seek "treatment as a State" for purposes of administering certain CAA programs, including the regional haze program. Whether Tribes seek this authority or not, EPA encourages Tribes to participate in the regional planning efforts to address visibility and to consult with neighboring States as they develop their regional haze SIPs. We hope that this guidance will provide Tribes with an understanding of the process for establishing RPGs that will assist them in the consultation process.

1.1 Legislative and Regulatory History

The CAA was amended in August 1977, and a new section 169A was added for the protection of visibility in mandatory class I Federal areas (Class I areas) of great scenic importance. In section 169A(a)(1), Congress established the national goal for visibility protection:

> *Congress hereby declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory class I Federal areas which impairment results from manmade air pollution.*

Section 169A(a)(4), in part, requires EPA to "promulgate regulations to assure reasonable progress toward meeting the national goal." The CAA also requires States to submit SIPs containing such emission limits, schedules of compliance, and other measures as may be necessary to make reasonable progress toward meeting the goal.[1]

[1] CAA § 169A(b)(2).

In the CAA Amendments of 1990, Congress added section 169B to strengthen and reaffirm the national goal. Section169B(e) calls for EPA to "carry out the Administrator's regulatory responsibilities under [section 169A], including criteria for measuring 'reasonable progress' toward the national goal."

In response to these mandates, EPA promulgated the regional haze rule (RHR) on July 1, 1999.[2] Under section 51.308(d)(1) of this rule, States must "establish goals (expressed in deciviews) that provide for reasonable progress towards achieving natural visibility conditions" for each Class I area within a State. These RPGs must provide for an improvement in visibility for the most impaired days over the period of the implementation plan and ensure no degradation in visibility for the least impaired days over the same period.[3]

The RHR also requires States to submit a long-term strategy that includes such measures as are necessary to achieve the RPG for each Class I area.[4] The regulations require States to consider major and minor stationary sources, mobile sources, and area sources in developing their long-term strategies. In addition, States must submit a SIP that contains either emission limitations representing best available retrofit technology (BART) for certain sources put into operation between 1962 and 1977 *or* alternative measures that provide for greater reasonable progress than BART.[5] The BART requirements were addressed in a rule revising certain provisions of the regulations in section 51.308(e) and promulgating the BART Guidelines.[6]

1.2 Meaning of the Term "Reasonable Progress Goal"

States must establish RPGs, measured in deciviews (dv), for each Class I area for the purpose of improving visibility on the haziest days and ensuring no degradation in visibility on the clearest days over the period of each implementation plan.[7] RPGs are interim goals that represent incremental visibility improvement over time toward the goal of natural background conditions and are developed in consultation with other affected States and Federal Land

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[2] 64 FR 35714 (codified at 40 CFR 51300-309).

[3] 40 CFR 51.308(d)(1).

[4] 40 CFR 51.308(d)(3).

[5] 40 CFR 51.308(e).

[6] 70 FR 39104 (July 6, 2005).

[7] 40 CFR 51.308(d)(1).

Managers (FLM).[8]

In determining what would constitute reasonable progress, section 169A(g) of the CAA requires States to consider the following four factors:

- The costs of compliance;
- The time necessary for compliance;
- The energy and non-air quality environmental impacts of compliance; and
- The remaining useful life of existing sources that contribute to visibility impairment.[9]

States must demonstrate in their SIPs how these factors are taken into consideration in selecting the RPG for each Class I area in the State.

The discussion of the statutory factors in this guidance is largely aimed at helping States apply these factors in considering measures for point sources. States may find that the factors can be applied to sources other than point sources; the meaning of the factors, however, should not be unduly strained in order to fit non-point sources. In other words, if common sense dictates that a particular statutory factor cannot be applied to a particular source category, then the State's analysis may reflect that fact, and emissions reductions from such sources may still be included in the SIP.

As noted above, the RHR establishes an additional analytical requirement for States in the process of establishing the RPG. This analytical requirement requires States to determine the rate of improvement in visibility needed to reach natural conditions by 2064, and to set each RPG taking this "glidepath" into account.[10] (The process for determining the glidepath is discussed later in this document.) EPA adopted this approach, in part, to ensure that States use a common analytical framework that accounts for the regional differences affecting visibility and, in part, to ensure an informed and equitable decision making process. The glidepath is not a presumptive target, and States may establish a RPG that provides for greater, lesser, or equivalent visibility improvement as that described by the glidepath.

[8] 40 CFR 51.308(d)(1)(iv) and 51.308(i).

[9] CAA §169A(g)(1); 40 CFR 51.308(d)(1)(i)(A).

[10] 40 CFR 51.308(d)(1)(i)(B).

In deciding what amount of emissions reduction is appropriate in setting the RPG, you should take into account the fact that the long-term goal of no manmade impairment encompasses several planning periods. It is reasonable for you to defer reductions to later planning periods in order to maintain a consistent glidepath toward the long-term goal.

1.3 Relationship of Reasonable Progress to BART and the Long-Term Strategy

The RPGs, the long-term strategy, and BART (or alternative measures in lieu of BART) are the three main elements of the regional haze SIPs that States are required to submit by December 17, 2007. The long-term strategy and BART emissions limitations or other alternative measures, including cap-and-trade programs or other economic incentive approaches, are inherently related to the RPG. The long-term strategy is the compilation of "enforceable emissions limitations, compliance schedules, and other measures as necessary to achieve the [RPGs],"[11] and is the means through which the State ensures that its RPG will be met. BART emissions limits (or alternative measures in lieu of BART, such as the Clean Air Interstate Rule (CAIR)) are one set of measures that must be included in the SIP to ensure that an area makes reasonable progress toward the national goal, and the visibility improvement resulting from BART (or a BART alternative) is included in the development of the RPG.

[11] 40 CFR 51.308(d)(3).

2.0 Overview Of the Process for Developing the RPG

Development of the RPG for each Class I area should be a collaborative process among State, local, and Tribal authorities, Regional Planning Organizations (RPOs), and FLMs. Steps for developing RPGs will be briefly outlined in this section of the guidance, along with references to other guidance and rules where additional detail can be found. The remaining sections of this guidance expand on particular aspects of these steps. In addition, as this is guidance for States in developing RPGs, the use of "you" through the rest of the document refers to States.

2.1 Establish Baseline and Natural Visibility Conditions

To track progress toward the national goal, the RHR, among other things, requires you to establish the "baseline conditions" representing visibility for the best and worst days at the time the regional haze program is established for each Class I area. Once established, the baseline represents the starting point from which reasonable progress will be measured. The RHR also requires you to estimate "natural conditions" for each Class I area that represents the visiblity conditions that would exist in the absence of man-made impairment.

As explained in the RHR, the baseline for each Class I area is the average visibility (in dv) for the 20 percent most impaired days, or "worst days", and for the 20 percent least impaired days, or "best days," for the years 2000 through 2004.[12] Using available monitoring data for the 2000 to 2004 time period, you are required to calculate the baseline by averaging the annual values (in dv) for the 20 percent worst days in each year (yr) to produce a single value (in dv) that represents the baseline conditions for the worst days. You should follow the same approach for determining the value that represents the baseline conditions for the best days. Natural conditions at each Class I area are also expressed by reference to the level of visibility (in dv) for the 20 percent most impaired and least impaired days.[13]

[12] 64 FR at 35730.

[13] For more detail on determining baseline and natural conditions, you can review the preamble and regulations in the RHR, 64 FR at 35728 – 35730, 40 CFR 51.308(d)(2), EPA's *Guidance for Tracking Progress Under the Regional Haze Rule*, EPA-454/B-03-004 (September 2003) available at www.epa.gov/ttn/oarpg/t1/memoranda/rh_tpurhr_gd.pdf, and EPA's *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule*, EPA-454/B-03-005 (September 2003) available at www.epa.gov/ttn/oarpg/t1/memoranda/rh_envcurhr_gd.pdf.

2.2 Determine the Glidepath, or Uniform Rate of Progress

By comparing baseline conditions with natural conditions, you can determine the uniform rate of visibility improvement, or progress, needed to reach natural conditions by 2064 for each Class I area. Figure 1, below, illustrates the basic steps in the process for calculating the uniform rate of progress toward natural conditions for the first planning period at a hypothetical Class I area.

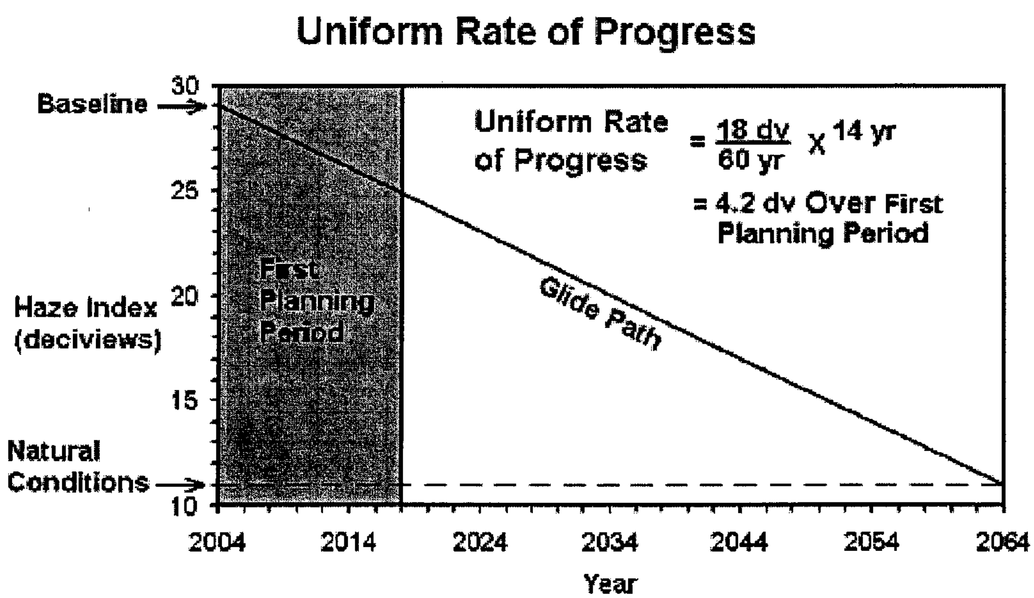

Figure 1

Figure 1 Example of a Uniform Rate of Progress

- Compare baseline conditions to natural conditions. The difference between these two represents the amount of progress needed to reach natural visibility conditions. In this example, the State has determined that the baseline for the 20 percent worst days for the Class I area is 29 dv and estimated that natural background is 11 dv, a difference of 18 dv.

- Calculate the annual average visibility improvement needed to reach natural conditions by 2064 by dividing the total amount of improvement needed by 60 years (the period between 2004 and 2064). In this example, this value is 0.3 dv/yr.

- Multiply the annual average visibility improvement needed by the number of years in the first planning period (the period from 2004 until 2018). In this example, this value is 4.2 dv. This is the uniform rate of progress that would be needed during the first planning period to attain natural visibility conditions by 2064.

If you were to achieve this steady improvement in visibility over the next 60 years, you would reach the national goal by 2064.

2.3 Identify and Analyze the Measures Aimed at Achieving the Uniform Rate of Progress.

The next step in setting an RPG is to identify and analyze the measures aimed at achieving the uniform rate of progress and to determine whether these measures are reasonable based on the statutory factors identified in Section 1.2 above. To meet this requirement, we suggest the following approach which ensures that States consider all reasonable measures in developing their regional haze SIPs:

- Identify the key pollutants and sources and/or source categories that are contributing to visibility impairment at each Class I area. The sources of impairment for the most impaired and least impaired days may differ. Section 3 discusses this process.

- Identify the control measures and associated emission reductions that are expected to result from compliance with existing rules *and* other available measures for the sources and source categories that contribute significantly to visibility impairment. This is covered in more detail in Section 4.

- Determine what additional control measures would be reasonable based on the statutory factors and other relevant factors for the sources and/or source categories you have identified.

- Estimate through the use of air quality models the improvement in visibility that would result from implementation of the control measures you have found to be reasonable and compare this to the uniform rate of progress.

Another possible approach that some States and RPOs are using is to "back out" the measures necessary to achieve the uniform rate of progress. In this process, States are using dispersion modeling to estimate the visibility impacts of a specific percentage reduction in visibility impairing pollutants. The resulting visibility conditions are then compared to the uniform rate of progress. Using this process, States will be able to identify a percentage reduction in visibility impairing pollutants that would provide progress at or beyond the uniform rate of progress. In a separate step, States would consider the statutory factors along with other relevant factors to select appropriate measures to achieve the identified reduction in emissions. States can thus identify the measures that would be needed to achieve the uniform rate of progress at a Class I area and determine whether such measures are reasonable.

2.4 Establish a RPG

In developing a RPG, you must consult with other States with emissions sources that may reasonably be anticipated to cause or contribute to visibility impairment at Class I areas in your State.[14] The regulations anticipate that States may not always agree on what measures would be reasonable or on the appropriateness of a RPG. We encourage States to work together early and often to resolve such issues. In addition, the FLMs may provide insight and assistance to States in identifying regional approaches to address the RPG.

The improvement in visibility resulting from implementation of the measures you have found to be reasonable, considering the uniform rate of progress, is the amount of progress that represents your RPG. The regional haze rule requires you to clearly support your RPG determination in your SIP submission based on the statutory factors.[15]

[14] 40 CFR 51.308(d)(1)(iv).

[15] 40 CFR 51.308(d)(1)(i)(A).

3.0 IDENTIFYING KEY POLLUTANTS AND SOURCE CATEGORIES FOR THE FIRST PLANNING PERIOD

This process begins with the identification of key pollutants and source categories that contribute to visibility impairment at the Class I area. Such analysis has been the subject of considerable study over the past decade, including studies by the Grand Canyon Visibility Transport Commission and ongoing work by RPOs. For the purpose of this document, it is assumed that analyses identifying the key pollutants contributing to visibility impairment have been conducted for each Class I area.

3.1 Identification of Source Categories From Which These Pollutants and Their Precursors Are Emitted

Once the key pollutants contributing to visibility impairment at each Class I area have been identified, the sources or source categories responsible for emitting these pollutants or pollutant precursors can also be determined. There are several tools and techniques being employed by the RPOs to do so, including analysis of emission inventories, source apportionment, trajectory analysis, and atmospheric modeling. Technical guidance on these tools and techniques is beyond the scope of this document. Instead, this document focuses on policy considerations relevant to the identification of which source categories should be considered as part of the regional haze SIP development process.

When identifying the sources or source categories responsible for regional haze, you should consider the relationship between the RPG and the requirements for long-term strategies. The regulations require States to consider major and minor stationary sources, as well as mobile and area sources, in developing long-term strategies.[14] At a minimum, the regulations require you to consider several factors when developing a long-term strategy, including the following:

- Emissions reductions due to ongoing air pollution control programs, including measures to address reasonably attributable visibility impairment and those taken to attain the fine particulate matter ($PM_{2.5}$) national ambient air quality standards (NAAQS).

- Measures to mitigate the impact of construction activities.

- Smoke management techniques for agricultural and forestry management purposes.

[14] 40 CFR 51.308(d)(3)(iv).

- Anticipated visibility effects from changes in point, area, and mobile source emissions.[17]

As illustrated by these factors, States should consider a broad array of sources and activities when deciding which sources or source categories contribute significantly to visibility impairment.

[17] 40 CFR 51.308(d)(3)(v).

4.0 IDENTIFY CONTROL MEASURES FOR CONTRIBUTING SOURCE CATEGORIES FOR THE FIRST PLANNING PERIOD

There are numerous possible conceptual approaches that you can use to identify control measures for the long-term strategy and the related RPG. We suggest beginning by concentrating on possible emissions reductions of several pollutant species from a few selected source sectors, focusing on those source categories that may have the greatest impact on visibility at Class I areas, considering cost and the other factors discussed further in Section 5.0.

4.1 Consideration of Emissions Reductions from State, Federal, and Local Control Measures

One important factor to keep in mind when establishing a RPG is that you cannot adopt a RPG that represents less visibility improvement than is expected to result from the implementation of other CAA requirements.[18] You must therefore determine the amount of emission reductions that can be expected from identified sources or source categories as a result of requirements at the local, State, and federal levels during the planning period of the SIP and the resulting improvements in visibility at Class I areas. Given the significant emissions reductions that we anticipate to result from BART, the CAIR, and the implementation of other CAA programs, including the ozone and $PM_{2.5}$ NAAQS, for many States this will be an important step in determining your RPG, and it may be all that is necessary to achieve reasonable progress in the first planning period for some States.

The first step in this process is to identify the baseline emissions inventory year on which your strategies are based. For the first RHR SIP, we anticipate that States will use 2002 as the baseline year for emission inventories.[19] If you do use 2002, you may take credit in your long-term strategy for emission reductions achieved after 2002. This includes emission reductions from measures implemented to attain the ozone and $PM_{2.5}$ NAAQS,[20] and Federal programs, such as the national mobile source program and federal standards for hazardous air pollutants (air toxics).

[18] 40 CFR 51.308(d)(1)(vi).

[19] 40 CFR 51.308(d)(3)(iii) provides that the baseline emission inventory year is presumed to be the most recent year of the consolidated emissions inventory for the SIP. A memorandum from OAQPS, entitled *2002 Base Year Emission Inventory SIP Planning: 8-hr Ozone, PM 2.5, and Regional Haze Programs* (November 18, 2002) ("2002 EI Memo"), identifies 2002 as the anticipated baseline emission inventory year for regional haze. See www.epa.gov/ttn/oarpg/t1/memoranda/2002bye_gm.pdf

[20] 2002 EI Memo at 3-4.

4.2 Identification of Additional Emissions Control Strategies for the Source Categories Identified

After determining the amount of emissions reductions of visibility impairing pollutants that may be expected from implementation of other CAA programs, you will be ready to identify any additional measures that are reasonable. The RHR gives States wide latitude to determine additional control requirements, and there are many ways to approach identifying additional reasonable measures; however, you must at a minimum, consider the four statutory factors. Based on the contribution from certain source categories and the magnitude of their emissions you may determine that little additional analysis is required to determine further controls are not warranted for that category. As discussed further in section 5, you have considerable flexibility in how you take these factors into consideration. In addition to source-specific controls, emissions cap-and-trade programs may be considered. Sources of information on control techniques for specific source categories include the RACT/BACT/LAER Clearinghouse and EPA's AIRControlNet database.[21]

One approach that you could take to streamline what could be an extremely complex task would be to first identify alternative control scenarios with different levels of stringency. Each control scenario would assume application of specific control levels or measures to the sources or source categories you have identified as the significant sources of visibility impairment. As indicated previously in section 4.1, the starting point for this assessment is the visibility improvement achieved as a result of BART, the CAIR, and the implementation of other CAA programs, including other measures for attainment of the ozone and $PM_{2.5}$ NAAQS. You would then consider whether any additional control scenarios are reasonable based on your consideration of the statutory factors and any other factors you have determined are relevant.

Another approach you could take, consistent with the "back out" approach discussed in section 2.3, would involve identifying the set of emissions control measures that achieves the target percentage reductions in visibility-impairing pollutants associated with progress at or beyond the uniform rate of progress. The selection of control measures to include in this set would be guided by your consideration of the statutory factors and any other factors you have determined are relevant.

Note that for some sources determined to be subject to BART, the State will already have completed a BART analysis. Since the BART analysis is based, in part, on an assessment of many of the same factors that must be addressed in establishing the RPG, it is reasonable to

[21] Information on AirControlNET can be found at www.epa.gov/ttn/ecas/ccontrol.html. The RACT/BACT/LAER Clearinghouse is located at http://cfpub.epa.gov/rblc/htm/bl02.cfm.

conclude that any control requirements imposed in the BART determination also satisfy the RPG-related requirements for source review in the first RPG planning period. Hence, you may conclude that no additional emissions controls are necessary for these sources in the first planning period.

5.0 Applying Statutory Factors to Potentially Affected Stationary Sources

In determining reasonable progress, CAA §169A(g)(1) requires States to take into consideration a number of factors. However, you have flexibility in how to take into consideration these statutory factors and any other factors that you have determined to be relevant. For example, the factors could be used to select which sources or activities should or should not be regulated, or they could be used to determine the level or stringency of control, if any, for selected sources or activities, or some combination of both. The factors may be considered both individually and/or in combination. As noted in section 4.1, given the significant emissions reductions that we anticipate to result from BART, the CAIR, and the implementation of other CAA programs, these reductions may be all that is necessary to achieve reasonable progress in the first planning period for some States. Also, as noted in section 4.2, it is not necessary for you to reassess the reasonable progress factors for sources subject to BART for which you have already completed a BART analysis.

5.1 Reasonable Progress Statutory Factor (a): Costs of Compliance

The first factor to take into consideration is the "costs of compliance." In this context we believe that the cost of compliance factor can be interpreted to encompass the cost of compliance for individual sources or source categories, and more broadly the implication of compliance costs to the health and vitality of industries within a state. For additional guidance on applying the cost of compliance factor to stationary sources, you may wish to consult the BART guidelines, referenced above.

To assess compliance costs for individual sources or source categories potentially subject to emission limitations, we suggest that you use established control cost analysis techniques. For stationary sources, generally this involves the following:[22]

a) Identify the emissions units to be controlled;

b) Identify the design parameters for emissions controls; and

c) Develop cost estimates based upon those design parameters.

[22] As noted above, application of the cost factor to non-point sources is beyond the scope of this guidance. This is also true for mobile sources.

You should evaluate both average and incremental costs. To maintain and improve consistency wherever possible, cost estimates should be based on EPA's *Air Pollution Control Cost Manual*.[23]

In considering the cost of compliance factor, you should keep in mind that different pollutants differently impact visibility impairment. For example, on a ton basis, sulfur dioxide-related particles have a greater impact on visibility impairment than crustal material. Therefore, in assessing additional emissions reduction strategies for source categories or individual, large scale sources, simple cost effectiveness estimates based on a dollar-per-ton calculation may not be as meaningful as a dollar-per-deciview calculation, especially if the strategies reduce different groups of pollutants.

5.2 Reasonable Progress Statutory Factor (b): Time Necessary for Compliance

The second factor is the "time necessary for compliance." It may be appropriate for you to use this factor to adjust the RPG to reflect the degree of improvement in visibility achievable within the period of the first SIP if the time needed for full implementation of a control measure (or measures) will extend beyond 2018. For example, if you anticipate that constraints on the availability of construction labor will preclude the installation of controls at all sources of a particular category by 2018, the visibility improvement anticipated from installation of controls at the percentage of sources that *could* be controlled within the strategy period should be considered in setting the RPG and in establishing the SIP requirements to meet the RPG.

5.3 Reasonable Progress Statutory Factor (c): Energy and Non-Air Impacts

The third factor is "energy and non-air environmental impacts." In assessing energy impacts, you may want to consider whether the energy requirements associated with a control technology result in energy penalties. For example, controls on diesel engines may decrease the engine's fuel efficiency, leading to an increase in diesel fuel consumption. Or, a particular control may require a fuel unavailable in the area. To the extent that these considerations are quantifiable they should be included in the engineering analyses supporting compliance cost estimates.

Some examples of non-air environmental impacts that you may wish to consider, are the effects of the waste stream that may be generated by a particular control technology, and/or other

[23] Any additional information used for the cost calculations, including any information supplied by vendors that affects your assumptions regarding purchased equipment costs, equipment life, replacement of major components, and any other element of the calculation that differs from the *Control Cost Manual*, should be documented. EPA's *Control Cost Manual* is located at: www.epa.gov/ttncatc1/products.html#cccinfo.

resource consumption rates such as water, water supply, and waste water disposal. To the extent that these considerations are quantifiable, they should also be included in the analyses supporting compliance cost estimates.

For additional guidance on applying this factor to stationary sources, you may wish to consult the BART Guidelines, referenced above.

5.4 Reasonable Progress Statutory Factor (d): The Remaining Useful Life of the Source

The fourth statutory factor is "the remaining useful life of any existing source subject to [reasonable progress] requirements." This factor is generally best treated as one element of the overall cost analysis. The "remaining useful life" of a source, if it represents a relatively short time period, may affect the annualized costs of retrofit controls. For example, the methods for calculating annualized costs in EPA's *Air Pollution Control Cost Manual* require the use of a specified time period for amortization that varies based upon the type of control. If the remaining useful life of the source will clearly exceed this time period, the remaining useful life factor has essentially no effect on control costs and on the reasonable progress determination process. Where the remaining useful life of the source is less than the time period for amortizing the costs of the retrofit control, you may wish to use this shorter time period in your cost calculations.

For additional guidance on applying this factor to stationary sources, you may wish to consult the BART Guidelines, referenced above.