BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 110007-EI
FLORIDA POWER & LIGHT COMPANY

AUGUST 26, 2011

ENVIRONMENTAL COST RECOVERY

PROJECTIONS
JANUARY 2012 THROUGH DECEMBER 2012

REVISED - ACTUAL/ESTIMATED
JANUARY 2011 THROUGH DECEMBER 2011

TESTIMONY & EXHIBITS OF:

T. J. KEITH
R. R. LABAUVE

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TJ Keith

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF TERRY J. KEITH

DOCKET NO. 110007-EI

AUGUST 26, 2011

Q. Please state your name and address.

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

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

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

Q. Have you previously testified in this docket or any other predecessor dockets?

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 FPL's Environmental Cost Recovery Clause (ECRC) projections for the January 2012 through December 2012 period.

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

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

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

A. Yes. Exhibit TJK-3 consists of eight documents, PSC Forms 42-1P through 42-8P and are provided in Appendix I. Form 42-1P summarizes the costs being presented at this time. Form 42-2P reflects the total jurisdictional costs for O&M activities. Form 42-3P reflects the total jurisdictional costs for capital investment projects. Form 42-4P consists of the calculation of depreciation expense and return on capital investment for each project. Form 42-5P gives the description and progress of environmental compliance activities and projects for the projected period. Form 42-6P reflects the calculation of the energy and demand allocation percentages by rate class. Form 42-7P reflects the calculation of the 2012 ECRC factors. Form 42-8P provides the capital structure, components and cost rates relied upon to calculate the revenue requirement rate of return applied to capital investments and working capital amounts included for recovery through the ECRC for the period January 2012 through December 2012.

Q. Has FPL revised its 2011 ECRC Actual/Estimated True-up amount that was filed on August 1, 2011?

A. Yes. The 2011 ECRC Actual/Estimated true-up amount has been revised to an over-recovery of $8,708,682, which represents a difference of $7,704 from the 2011 Actual/Estimated true-up amount of $8,700,978 filed on August 1, 2011. This revised Actual/Estimated true-up over-recovery of $8,708,682 reflects a formula correction on Form 42-8E

(Appendix I, Page 58) for the Martin Next Generation Solar Energy Center Project No. 39. FPL requests that the Commission approve its revised 2011 Actual/Estimated true-up over-recovery of $8,708,682. Although only Forms 42-1E, 42-2E, 42-3E, 42-6E, 42-7E and Page 58 of Form 42-8E have been revised to reflect this correction, I have included a copy of my entire Exhibit TJK-2 with this filing for the convenience of the Commission, Staff and parties.

Q. Please describe Form 42-1P.

A. Form 42-1P (Appendix I, Page 2) provides a summary of projected environmental costs being presented for the period January 2012 through December 2012. Total environmental requirements, adjusted for revenue taxes, are $182,053,636 (Appendix I, Page 2, Line 5) and include $195,667,760 of environmental project jurisdictional revenue requirements for the January 2012 through December 2012 period (Appendix I, Page 2, Line 1c) decreased by the actual/estimated true-up over-recovery of $8,708,682 for the January 2011 - December 2011 period (Appendix I, Page 2, Line 2), and by the final true-up over-recovery of $5,036,426 for the January 2010 – December 2010 period (Appendix I, Page 2, Line 3).

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

A. Form 42-2P (Appendix I, Pages 3 and 4) presents the environmental project O&M costs for the projected period along with the calculation of total jurisdictional costs for these projects, classified by energy and demand. Form 42-3P (Appendix I, Pages 5 and 6) presents the environmental project capital investment costs for the projected period. Form 42-3P also provides the calculation of total jurisdictional costs for these projects, classified by energy and demand. The method of classifying costs presented in Forms 42-2P and 42-3P is consistent with Order No. PSC-94-0393-FOF-EI for all projects.

Q. Please describe Form 42-4P.

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

Q. Please describe Form 42-5P.

A. Form 42-5P (Appendix I, Pages 66 through 129) provides the description and progress of environmental projects included in the projected period.

Q. Please describe Form 42-6P.

A. Form 42-6P (Appendix I, Page 130) calculates the allocation factors for demand and energy at generation. The demand allocation factors are calculated by determining the percentage each rate class contributes to the monthly system peaks. The energy allocators are calculated by determining the percentage each rate class contributes to total kWh sales, as adjusted for losses.

Q. Please describe Form 42-7P.

A. Form 42-7P (Appendix I, Page 131) presents the calculation of the proposed 2012 ECRC factors by rate class.

Q. Please describe Form 42-8P.

A. Form 42-8P (Appendix I, Page 132) presents the capital structure, components and cost rates relied upon to calculate the revenue requirement rate of return applied to capital investments and working capital amounts included for recovery through the ECRC for the period January 2012 through December 2012.

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

A. Yes, with the exception of the St. Lucie Cooling Water Discharge Monitoring Project filed in this Docket on January 12, 2011, the National Pollutant Discharge Elimination System (NPDES) Permit Renewal Requirements Project presented in the August 1, 2011 testimony of Randall R. LaBauve, and the Industrial Boiler MACT Project, for which FPL is now petitioning for approval and which is discussed and supported in Mr. LaBauve's August 26, 2011 testimony.

Q. Is FPL including any costs in its 2012 ECRC factors associated with its 800 MW Units ESP Project, approved by the Commission in Order PSC-11-0083-FOF-EI, issued on January 31, 2011?

A. Yes. FPL has included $411,120 of O&M expenses and $7,072,368 of return requirements associated with its 800 MW Unit ESP Project in its 2012 ECRC factors, per the stipulation approved in the above mentioned order. Under the stipulation,

> "FPL shall be allowed to recover the reasonable and prudent costs associated with its proposed 800 MW Units Electro Static Precipitators (ESPs) Project (the "ESP Project") for compliance

with the United States Environmental Protection Agency's (EPA's) maximum achievable control technology (MACT) rule in the following manner and under the following conditions:

1. FPL is authorized to proceed with implementation of the ESP Project at the time that EPA issues a proposed MACT rule that has the effect of requiring ESPs at oil-fired power plants, such as FPL's 800 MW units. FPL will consult with Staff and interested parties at the time that EPA issues the proposed MACT rule, concerning the rule's requirement for ESPs and FPL's decision on whether to proceed with the ESP Project pursuant to those proposed requirements.

2. During the period between EPA's issuance of the proposed MACT rule and issuance of the final MACT rule, FPL will exclude the costs incurred for the ESP project from the ECRC-recoverable accounts and instead will be authorized to record the cost of the ESP work in non-ECRC construction accounts and accrue a return at the then-current authorized AFUDC rate on the amounts recorded in the non-ECRC construction accounts.

3. If the final MACT rule requires ESPs, then FPL would be authorized to transfer the balance of all reasonable and prudent costs from the non-ECRC construction accounts, which would

include all accrued AFUDC, to ECRC-recoverable accounts and begin the normal process of ECRC recovery for those and future reasonable and prudent capital expenditures and O&M expenses associated with the ESP Project."

As presented in the testimony of FPL witness LaBauve, the Environmental Protection Agency (EPA) issued the proposed Air Toxics Rule on March 16, 2011, which was published in the Federal Register on June 21, 2011. FPL continues to believe that the installation of ESPs at the Martin and Manatee plants is the most effective method to comply with the requirements of the proposed rule.

FPL anticipates that EPA will finalize the Air Toxics Rule by the November 16, 2011 deadline in compliance with the Court's order. Assuming that occurs, then FPL will be entitled by the terms of the stipulation to recover costs for the 800 MW Unit ESP Project in its 2012 ECRC factors. As such, FPL believes it is appropriate to include costs associated with the project in the 2012 ECRC factors. Of course, if it turns out that the final Air Toxics Rule were significantly delayed or did not require ESPs at those units, then FPL would make appropriate adjustments to the 2012 ECRC recovery via the true-up mechanism.

Q. Does this conclude your testimony?

A. Yes, it does.

RR LaBauve

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RANDALL R. LABAUVE

DOCKET NO. 110007-EI

AUGUST 26, 2011

Q. Please state your name and address.

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

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

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

Q. Have you previously testified in this or predecessor dockets?

A. Yes, I have.

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

A. The purpose of my testimony is to present for Commission review and approval a new environmental project, the Industrial Boiler MACT Project. Additionally, my testimony provides a brief update on FPL's 800MW Units MACT Compliance Project.

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

A. Yes. I am sponsoring the following exhibits:

- RRL-6 – Pertinent Excerpts from Final Industrial Boiler MACT Rule for Area Sources 40-CFR Part 63 Subpart DDDDD

- RRL-7 – Pertinent Excerpts from Final Industrial Boiler MACT Rule for Area Sources 40-CFR Part 63 Subpart JJJJJJ
- RRL-8 – EPA Delay of Subpart DDDDD
- RRL-9 – ERG Memorandum
- RRL-10 – FPL IB MACT Cost Matrix

Industrial Boiler MACT Project

Q. Please describe the law or regulation requiring the Industrial Boiler MACT Project.

A. The Environmental Protection Agency (EPA) regulates Hazardous Air Pollutants (HAPs) under Section 112 of the Clean Air Act (CAA). EPA promulgates emission standards for HAPs under 40 CFR Part 63 for stationary source categories. On February 21, 2011, the final Industrial/Commercial/Institutional Boiler Maximum Achievable Control Technology (IB MACT) rules were signed by the EPA Administrator. EPA's two rules address boilers and process heaters under Subpart DDDDD (40 CFR 63.7480) for affected units at major sources and Subpart JJJJJJ (40 CFR 63.11193) for affected units at area sources.

Subpart DDDDD (40 CFR 63.7480) affects FPL industrial boilers and process heaters at facilities that are classified as major sources of HAPs by requiring these smaller pieces of equipment to comply with the rule as applicable (i.e., testing, monitoring, tune-ups and site assessments as determined by the specifics of the equipment). The pertinent excerpts from Subpart DDDDD are included as Exhibit RRL-6 to my testimony.

Subpart JJJJJJ (40 CFR 63.11193) affects FPL industrial boilers at facilities that are classified as minor sources of HAPs by requiring the oil-fired boilers at the sites to comply with the rule as applicable (again, this entails testing, monitoring, tune-ups and site assessments as determined by the specifics of the equipment). The pertinent excerpts from Subpart JJJJJJ are included as Exhibit RRL-7 to my testimony.

FPL owns and operates units affected by both of these regulations at several power generation and fuel oil storage facilities. On May 18, 2011, EPA delayed the effective date of Subpart DDDDD until such time as judicial review is no longer pending or until the EPA completes its reconsideration of the rule. The section of the Federal Register that addressed EPA's delay of Subpart DDDDD is Exhibit RRL-8 to my testimony. FPL anticipates that EPA will lift its stay of the Subpart DDDDD effectiveness prior to spring 2012. The delay in the effective date for Subpart DDDDD does not apply to Subpart JJJJJJ, which became effective on March 21, 2011.

Because Subpart DDDDD is currently stayed, FPL has included in its 2012 ECRC projections only costs for compliance with Subpart

JJJJJJ. However, FPL requests that the Commission also authorize FPL to seek recovery of costs incurred to comply with Subpart DDDDD if the stay is lifted and the rule becomes effective. As noted above, EPA anticipates that the stay will be lifted no later than Spring 2012.

Q. How does the Industrial Boiler MACT affect FPL?

A. The IB MACT rule imposes new emission limitations, work practice standards, and operating limits on the affected source categories to reduce the emission of HAPs at major source (Subpart DDDDD) and area source (Subpart JJJJJJ) facilities. Major sources of HAPs are those facilities which have the potential to emit more than 10 tons of any one HAP, or 25 tons of a combination of HAPs in any one year. Area sources are those facilities that have the potential to emit HAPs in quantities below the major source thresholds. FPL's fossil generation plants are typically major sources for HAPs, so industrial boilers and process heaters at those plants would be impacted by Subpart DDDDD. FPL facilities classified as area sources for HAPs have boilers that must comply with Subpart JJJJJJ, but the rule does not apply to process heaters at those lower emitting sites. EPA has established different compliance requirements for sources by creating subcategories for different fuels under each rule and for new versus existing sources. Under Subparts DDDDD and JJJJJJ, a boiler is defined as new if construction commenced after June 4, 2010 and existing sources as those which were constructed prior to that date.

Equipment that is subject to the IB MACT rule includes fuel oil boilers that heat fuel at FPL oil terminals for storage and pipeline delivery to plants; auxiliary boilers for production of steam for gas turbine blade cooling during unit start-up; auxiliary boilers for steam turbine heating during combined cycle unit outages; process heaters for natural gas fuel heating for use in gas turbines; and auxiliary boilers for warm water discharge for manatee protection during cold weather events.

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

A. FPL's plan to comply with the requirements of the IB MACT rule includes the following:

- Submittal of initial notifications of applicability to agencies
- Development of site specific monitoring plans for those units which will not use continuous emission monitors
- Conducting initial emission stack tests to determine compliance status with applicable emission limits for oil-fired units
- Performing required fuel oil sampling and analyses for oil-fired units
- Conducting required biennial tune-up work practices including the purchase of required emission analyzers for boiler tune-ups
- Performing one-time energy assessment required for affected units at both area and major source facilities
- Installation of emission controls or replacement of existing units

that cannot demonstrate compliance with applicable emission standards

Q. What are the compliance dates for this project?

A. FPL is required to provide notification to the Florida Department of Environmental Protection of its area sources regulated under Subpart JJJJJJ no later than September 16, 2011. FPL proposes to conduct required emission testing in 2012 to develop its plan for the lowest cost of compliance for equipment at those areas sources which have emission specifications. Should affected emission units not meet the specifications, FPL will conduct an engineering study to evaluate compliance options including installation of controls or replacement of emission units.

FPL also plans to begin performing in 2012 the energy assessments at affected area sources that are required by Subpart JJJJJJ and, once the stay of Subpart DDDDD is lifted, FPL will proceed with required facility energy assessments at the affected major-source facilities. FPL will have on-going compliance costs associated with newly required biennial unit tune-ups and from additional fuel oil testing. FPL does not yet know, and cannot yet estimate, whether any affected units would require installation of controls or replacement but anticipates that those costs would likely occur in 2013 or later. Under Section 112 of the CAA any required controls must be in place no later than three years after the final rule.

Q. How has FPL estimated the costs for compliance with the Industrial Boiler MACT rule?

A. In its development of the IB MACT rule, EPA estimated compliance costs. Exhibit RRL-9 provides the supporting document for the development of EPA's cost estimates. FPL has not yet sought bids for activities and equipment which may be required by the IB MACT rule and instead has used the EPA cost estimates for each of the applicable rule requirements for FPL's industrial boilers and process heaters. The preliminary estimate for the initial testing and energy assessment requirements are projected at $397,000 and annual emission/fuel testing costs are projected at $26,000. FPL has evaluated the expected compliance costs for each of its facilities that are subject to the requirements of Subpart JJJJJJ and Subpart DDDDD using the EPA cost estimates for required activities. Exhibit RRL-10 provides FPL's estimates of compliance costs with EPA's IB MACT rule. FPL cannot yet predict what compliance costs may have to be incurred for installation of controls or replacement of affected units.

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

A. Consistent with our standard practice for all contractor service procurements, FPL will competitively bid the contractor selection for the Industrial Boiler MACT project activities where possible.

Q. Is FPL recovering through any other mechanism the costs for the

Industrial Boiler MACT Project?

A. No. FPL is only requesting recovery of incremental activities associated with the Industrial Boiler MACT Project.

<u>800 MW Units MACT Compliance Project Update</u>

Q. Please provide an update of the EPA proposed Air Toxics Rule.

A. As anticipated in my testimony filed on August 27, 2010 in Docket No. 100007-EI, on March 16, 2011 the EPA issued a proposed rule that would reduce emissions of toxic air pollutants from power plants. Specifically, the proposed air toxics rule would reduce emissions of heavy metals, including mercury (Hg), arsenic, chromium, and nickel, and acid gases, including hydrogen chloride (HCl) and hydrogen fluoride (HF), from new and existing coal- and oil-fired electric utility steam generating units (EGUs). Following the publication of the proposed rule, on June 21, 2011 EPA extended the timeline for public input by 30 days on the proposed rule accepting comments on the proposal until August 4, 2011.

Q. Has FPL provided comments to EPA on the proposed Air Toxics Rule?

A. Yes. In FPL's review of the rule there were specific provisions of the rule which FPL believes were inappropriately included in the proposed rule. Specifically, FPL provided comments on the following issues: (1) Testing required to demonstrate eligibility as Low Emitting Units; (2) Startup, Shutdown and Malfunction exemption; (3) Use of emission averaging among affected units at a facility; (4) Filterable Particulate Matter (PM) measurement in lieu of total PM measurement; (5) Reconsideration and removal of nickel emission requirements for oil-fired units; (6) Re-evaluation and removal of acid-gas emission requirements for oil-fired units; and (7) Inclusion of a limited-use category for units with operation on oil limited to less than 10% annually. On August 4, 2011, FPL filed its comments via regulations.gov, Docket ID No. EPA-HQ-OAR-2009-0234. FPL also participated in joint comments filed on behalf of the Clean Energy Group and The Class of '85 regulatory group.

Q. Please provide an update on the 800 MW Units MACT Compliance Project.

A. Consistent with the stipulation approved by the Commission in Order No. PSC-11-0083-FOF-EI, issued in Docket No. 100007-EI on January 31, 2011, FPL began the process of installing an ESP on Manatee Unit 2 with the award of the contract to Siemens as amended on May 2, 2011. Construction site mobilization for this installation is projected to begin September 5, 2011 with unit construction activities projected to begin October 3, 2011. On October 5, 2011 Manatee Unit 2 will begin the planned outage and will be removed from service until May 26, 2012. Final acceptance of the ESP following initial operation and performance testing to ensure that manufacturer guarantees have been met is projected to occur on September 26, 2012. FPL's current construction plan for the installation of ESPs will ensure that the units will meet the deadline imposed under Section 112 of the CAA.

Q. Has FPL included costs associated with the 800 MW Units MACT Compliance Project in its 2012 ECRC projections?

A. Yes. FPL anticipates that EPA will meet the court's November 16, 2011 deadline for finalizing the air toxics rule as it did in meeting the court's March 16, 2011 deadline for proposing the rule. Assuming that the rule is finalized by the deadline and continues to require ESPs for the 800 MW generating units as FPL expects, then FPL's costs for the project will be eligible for 2012 ECRC recovery in accordance with the approved stipulation. Of course, if it turns out that the final rule were significantly delayed or did not require ESPs at those units, then FPL would make appropriate adjustments to the 2012 ECRC recovery via the true-up mechanism.

Q. Does this conclude your testimony?

A. Yes.

Appendix I

APPENDIX I

ENVIRONMENTAL COST RECOVERY

COMMISSION FORMS 42-1P THROUGH 42-8P
JANUARY 2012 – DECEMBER 2012

TJK-3
DOCKET NO. 110007-EI
FPL WITNESS: T.J. KEITH
EXHIBIT ______
PAGES 1-132

Form 42-1P

Florida Power & Light Company
Environmental Cost Recovery Clause
Total Jurisdictional Amount to Be Recovered

For the Projected Period
January 2012 to December 2012

Line No.		Energy ($)	CP Demand ($)	GCP Demand ($)	Total ($)
1	Total Jurisdictional Rev. Req. for the projected period				
	a Projected O&M Activities (FORM 42-2P, Page 2 of 2, Lines 7 through 9)	14,602,725	11,451,136	2,539,598	28,593,459
	b Projected Capital Projects (FORM 42-3P, Page 2 of 2, Lines 7 through 9)	23,373,637	143,700,664	0	167,074,301
	c Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b)	37,976,362	155,151,800	2,539,598	195,667,760
2	True-up for Estimated Over/(Under) Recovery for the current period January 2011 - December 2011 (FORM 42-1E, Line 4, filed on August 1, 2011 and revised on August 26, 2011)	1,739,124	6,840,670	128,888	8,708,682
3	Final True-up Over/(Under) for the period January 2010 - December 2010 (FORM 42-1A, Line 7, filed on April 1, 2011)	1,174,495	3,819,122	42,810	5,036,426
4	Total Jurisdictional Amount to be Recovered/(Refunded) in the projection period January 2012 - December 2012 (Line 1 - Line 2 - Line 3)	35,062,744	144,492,008	2,367,900	181,922,652
5	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier 1.00072)	35,087,989	144,596,043	2,369,605	182,053,636

Notes:

Allocation to energy and demand in each period are in proportion to the respective period split of costs.

True-up costs are split in proportion to the split of actual demand-related and energy-related costs from respective true-up periods.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Projection Amount for the Period
January 2012 - December 2012

O&M Activities
(in Dollars)

Line # Project #	Estimated JAN	Estimated FEB	Estimated MAR	Estimated APR	Estimated MAY	Estimated JUN	6-Month Sub-Total
1 Description of O&M Activities							
1 Air Operating Permit Fees	$107,500	$107,500	$107,500	$107,500	$107,500	$107,500	$645,000
3a Continuous Emission Monitoring Systems	158,711	34,096	55,846	34,096	34,096	63,847	380,692
5a Maintenance of Stationary Above Ground Fuel Storage Tanks	1,500	20,500	15,000	4,505	114,500	0	156,005
8a Oil Spill Cleanup/Response Equipment	17,717	17,717	17,717	17,717	17,717	17,717	106,302
13 RCRA Corrective Action	8,333	8,333	8,333	8,333	8,333	8,333	49,998
14 NPDES Permit Fees	115,200	0	0	0	0	0	115,200
17a Disposal of Noncontainerized Liquid Waste	30,000	30,000	36,000	2,500	60,000	0	158,500
19a Substation Pollutant Discharge Prevention & Removal - Distribution	261,250	331,250	331,250	331,250	261,250	171,250	1,687,500
19b Substation Pollutant Discharge Prevention & Removal - Transmission	84,869	89,869	89,869	89,869	84,869	69,869	509,214
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	(49,790)	(49,790)	(49,790)	(49,790)	(51,864)	(50,534)	(301,556)
21 St. Lucie Turtle Net	0	0	0	0	0	0	0
22 Pipeline Integrity Management	0	0	0	50,000	0	0	50,000
23 SPCC - Spill Prevention, Control & Countermeasures	76,019	76,019	76,019	76,019	78,235	79,918	462,229
24 Manatee Reburn	41,667	41,667	241,667	41,667	41,667	41,667	450,002
25 Pt. Everglades ESP Technology	53,334	53,334	53,334	53,334	53,334	53,334	320,004
27 Lowest Quality Water Source	27,476	27,476	27,476	27,476	27,476	27,476	164,856
28 CWA 316(b) Phase II Rule	17,668	17,366	17,868	17,556	18,179	17,557	106,194
29 SCR Consumables	29,167	29,167	29,167	29,167	29,167	29,167	175,002
30 HBMP	2,971	2,971	2,971	2,971	2,971	2,971	17,826
31 CAIR Compliance	387,667	387,667	387,667	387,667	387,667	387,667	2,326,002
32 BART	0	0	0	0	0	0	0
33 CAMR Compliance	265,333	265,333	265,333	265,333	265,333	265,333	1,591,998
34 St. Lucie Cooling Water System Inspection & Maintenance	0	0	0	0	0	0	0
35 Martin Plant Drinking Water System Compliance	1,667	1,667	1,667	1,667	1,667	1,667	10,002
36 Low-Level Radioactive Waste Storage	0	0	0	0	0	0	0
37 DeSoto Next Generation Solar Energy Center	91,949	115,853	87,371	76,433	109,609	81,934	563,149
38 Space Coast Next Generation Solar Energy Center	45,994	54,719	53,038	49,739	44,889	54,814	303,193
39 Martin Next Generation Solar Energy Center	200,787	200,787	200,787	200,787	200,787	200,787	1,204,722
40 Greenhouse Gas Reduction Program	12,000	0	12,000	0	0	12,000	36,000
41 Manatee Temporary Heating System Project	296,456	165,224	169,371	147,022	50,000	0	828,073
42 Turkey Point Cooling Canal Monitoring Plan	110,000	110,000	110,000	110,000	110,000	110,000	660,000
43 NESHAP Information Collection Request Project	0	0	0	0	0	0	0
44 Martin Plant Barley Barber Swamp Iron Mitigation Project	0	0	0	1,125	0	0	1,125
45 800 MW Unit ESP Project	0	0	0	0	0	0	0
46 St. Lucie Cooling Water Discharge Monitoring Project	11,334	43,854	46,172	80,311	47,791	79,501	308,963
47 NPDES IWW Permits	10,000	16,800	0	0	9,200	10,000	46,000
48 Industrial Boiler MACT Project	0	9,146	19,289	2,875	9,146	9,146	49,602
2 Total of O&M Activities	$2,370,093	$2,161,839	$2,366,236	$2,120,443	$2,076,833	$1,806,235	$12,901,681
3 Recoverable Costs Allocated to Energy	$1,464,495	$1,197,033	$1,440,930	$1,151,331	$1,109,350	$1,041,277	$7,404,415
4a Recoverable Costs Allocated to CP Demand	$667,691	$656,900	$617,400	$661,206	$729,576	$617,051	$3,949,823
4b Recoverable Costs Allocated to GCP Demand	$237,907	$307,907	$307,907	$307,907	$237,907	$147,907	$1,547,442
5 Retail Energy Jurisdictional Factor	98.08128%	98.08128%	98.08128%	98.08128%	98.08128%	98.08128%	
6a Retail CP Demand Jurisdictional Factor	98.01395%	98.01395%	98.01395%	98.01395%	98.01395%	98.01395%	
6b Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	
7 Jurisdictional Energy Recoverable Costs (A)	$1,436,396	$1,174,065	$1,413,282	$1,129,240	$1,088,064	$1,021,298	$7,262,345
8a Jurisdictional CP Demand Recoverable Costs (B)	$654,431	$643,853	$605,138	$648,074	$715,087	$604,796	$3,871,379
8b Jurisdictional GCP Demand Recoverable Costs (C)	$237,907	$307,907	$307,907	$307,907	$237,907	$147,907	$1,547,442
9 Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$2,328,734	$2,125,825	$2,326,327	$2,085,221	$2,041,058	$1,774,001	$12,681,166

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

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Projection Amount for the Period
January 2012 - December 2012

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	$107,500	$107,500	$107,500	$107,500	$107,500	$107,500	$645,000	$1,290,000			$1,290,000
3a Continuous Emission Monitoring Systems	158,711	34,096	55,846	34,096	34,093	56,922	373,764	754,456			754,456
5a Maintenance of Stationary Above Ground Fuel *Storage Tanks*	0	150,000	0	0	0	1,886,738	2,036,738	2,192,743	2,192,743		
8a Oil Spill Cleanup/Response Equipment	17,717	17,717	17,716	17,716	17,716	17,716	106,298	212,600			212,600
13 RCRA Corrective Action	8,333	8,333	8,334	8,334	8,334	8,334	50,002	100,000	100,000		
14 NPDES Permit Fees	0	0	0	0	0	0	0	115,200	115,200		
17a Disposal of Noncontainerized Liquid Waste	0	2,500	0	0	60,000	0	62,500	221,000			221,000
19a Substation Pollutant Discharge Prevention & Removal - Distribution	171,250	171,250	171,250	196,250	240,964	181,250	1,132,214	2,819,714		2,819,714	
19b Substation Pollutant Discharge Prevention & Removal - Transmission	69,869	69,869	84,869	109,869	74,869	66,870	476,215	985,429	909,627		75,802
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	(50,259)	(50,259)	(50,259)	(50,259)	(50,259)	(50,259)	(301,556)	(603,113)			(603,113)
21 St. Lucie Turtle Net	0	0	0	0	0	0	0	0	0		
22 Pipeline Integrity Management	0	0	0	200,000	0	226,500	426,500	476,500	476,500		
23 SPCC - Spill Prevention, Control & Countermeasures	83,518	80,818	76,318	78,234	76,018	96,055	490,961	953,190	953,190		
24 Manatee Reburn	41,667	41,667	41,666	41,666	241,666	41,666	449,998	900,000			900,000
25 Pt. Everglades ESP Technology	53,334	53,334	53,334	53,334	53,334	53,326	319,996	640,000			640,000
27 Lowest Quality Water Source	27,476	27,476	27,476	27,476	27,475	27,475	164,854	329,710	329,710		
28 CWA 316(b) Phase II Rule	17,868	18,179	17,247	18,179	17,868	987,556	1,076,897	1,183,091	1,183,091		
29 SCR Consumables	29,167	29,167	29,166	29,166	29,166	29,166	174,998	350,000			350,000
30 HBMP	2,971	2,971	2,971	2,971	2,971	2,971	17,826	35,652	35,652		
31 CAIR Compliance	387,667	387,667	387,667	387,667	387,667	387,663	2,325,998	4,652,000			4,652,000
32 BART	0	0	0	0	0	0	0	0			0
33 CAMR Compliance	265,333	265,333	265,333	265,333	265,333	372,337	1,699,002	3,291,000			3,291,000
34 St. Lucie Cooling Water System Inspection & Maintenance	0	0	0	0	0	0	0	0	0		
35 Martin Plant Drinking Water System Compliance	1,667	1,667	1,667	1,667	1,667	1,663	9,998	20,000	20,000		
36 Low-Level Radioactive Waste Storage	0	0	0	0	0	0	0	0	0		0
37 DeSoto Next Generation Solar Energy Center	88,372	114,808	80,895	85,308	98,871	77,433	545,687	1,108,836	1,108,836		
38 Space Coast Next Generation Solar Energy Center	43,539	44,940	59,915	49,440	44,539	52,290	294,663	597,856	597,856		
39 Martin Next Generation Solar Energy Center	200,787	200,787	200,787	250,787	200,787	220,787	1,274,722	2,479,444	2,479,444		
40 Greenhouse Gas Reduction Program	0	0	12,000	0	0	12,000	24,000	60,000			60,000
41 Manatee Temporary Heating System Project	0	0	15,000	15,000	226,000	251,000	507,000	1,335,073			1,335,073
42 Turkey Point Cooling Canal Monitoring Plan	110,000	110,000	110,000	110,000	110,000	110,000	660,000	1,320,000			1,320,000
43 NESHAP Information Collection Request Project	0	0	0	0	0	0	0	0			0
44 Martin Plant Barley Barber Swamp Iron Mitigation Project	0	0	1,125	0	0	0	1,125	2,250	2,250		
45 800 MW Unit ESP Project	0	82,224	82,224	82,224	82,224	82,224	411,120	411,120			411,120
46 St. Lucie Cooling Water Discharge Monitoring Project	47,791	162,535	128,396	107,073	137,973	105,454	689,222	998,185	998,185		
47 NPDES IWW Permits	0	16,800	0	0	10,800	0	27,600	73,600	73,600		
48 Industrial Boiler MACT Project	54,435	41,453	101,036	90,893	10,143	18,292	316,252	365,854	365,854		
2 Total of O&M Activities	$1,892,027	$2,146,146	$2,042,793	$2,273,238	$2,471,033	$5,384,243	$16,209,478	$29,111,156	$11,683,169	$2,539,598	$14,888,391
3 Recoverable Costs Allocated to Energy	$1,124,416	$1,084,525	$1,131,925	$1,100,098	$1,568,403	$1,474,609	$7,483,976	$14,888,391			
4a Recoverable Costs Allocated to CP Demand	$619,704	$913,714	$762,960	$1,000,232	$685,008	$3,751,727	$7,733,346	$11,683,169			
4b Recoverable Costs Allocated to GCP Demand	$147,907	$147,907	$147,907	$172,907	$217,621	$157,907	$992,156	$2,539,598			
5 Retail Energy Jurisdictional Factor	98.08128%	98.08128%	98.08128%	98.08128%	98.08128%	98.08128%					
6a Retail CP Demand Jurisdictional Factor	98.01395%	98.01395%	98.01395%	98.01395%	98.01395%	98.01395%					
6b Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%					
7 Jurisdictional Energy Recoverable Costs (A)	$1,102,841	$1,063,716	$1,110,207	$1,078,991	$1,538,310	$1,446,315	$7,340,380	$14,602,725			
8a Jurisdictional CP Demand Recoverable Costs (B)	$607,396	$895,567	$747,807	$980,367	$671,404	$3,677,216	$7,579,757	$11,451,136			
8b Jurisdictional GCP Demand Recoverable Costs (C)	$147,907	$147,907	$147,907	$172,907	$217,621	$157,907	$992,156	$2,539,598			
9 Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,858,144	$2,107,190	$2,005,921	$2,232,265	$2,427,335	$5,281,438	$15,912,293	$28,593,459			

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

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Projection Amount for the Period
January 2012 - December 2012

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line # Project #	Estimated JAN	Estimated FEB	Estimated MAR	Estimated APR	Estimated MAY	Estimated JUN	6-Month Sub-Total
1 Description of Investment Projects (A)							
2 Low NOx Burner Technology	$26,468	$26,310	$26,151	$25,993	$25,835	$25,677	$156,433
3b Continuous Emission Monitoring Systems	55,084	54,889	54,694	54,499	56,842	59,180	335,188
4b Clean Closure Equivalency	171	170	170	169	169	168	1,016
5b Maintenance of Stationary Above Ground Fuel Storage Tanks	85,298	85,110	84,922	84,734	84,546	84,358	508,967
7 Relocate Turbine Lube Oil Underground Piping to Above Ground	131	130	130	129	129	128	778
8b Oil Spill Cleanup/Response Equipment	11,893	11,827	11,770	11,714	11,657	11,601	70,462
10 Relocate Storm Water Runoff	693	691	690	688	687	686	4,135
NA SO2 Allowances-Negative Return on Investment	(14,186)	(13,787)	(13,389)	(12,990)	(12,605)	(12,219)	(79,176)
12 Scherer Discharge Pipeline	4,691	4,678	4,665	4,652	4,639	4,626	27,949
20 Wastewater Discharge Elimination & Reuse	10,316	10,296	10,277	10,258	10,238	10,219	61,605
21 St. Lucie Turtle Net	8,826	8,822	8,818	8,814	8,809	8,805	52,894
22 Pipeline Integrity Management	11,973	11,956	11,938	11,921	11,904	11,887	71,579
23 SPCC - Spill Prevention, Control & Countermeasures	169,648	169,853	170,056	169,863	169,669	169,475	1,018,565
24 Manatee Reburn	277,360	276,809	276,259	275,708	275,158	274,607	1,655,902
25 Pt. Everglades ESP Technology	677,948	676,734	675,519	674,304	673,089	671,874	4,049,469
26 UST Removal / Replacement	1,022	1,020	1,018	1,017	1,015	1,014	6,106
31 CAIR Compliance	4,289,434	4,299,415	4,323,623	4,715,461	5,109,862	5,137,236	27,875,032
33 CAMR Compliance	1,052,556	1,050,752	1,049,011	1,047,274	1,045,531	1,043,786	6,288,911
35 Martin Plant Drinking Water System Compliance	2,185	2,181	2,178	2,175	2,171	2,168	13,058
36 Low-Level Radioactive Waste Storage	65,185	65,102	65,019	96,164	127,270	127,108	545,849
37 DeSoto Next Generation Solar Energy Center	1,478,757	1,475,119	1,471,761	1,468,429	1,464,816	1,461,306	8,820,188
38 Space Coast Next Generation Solar Energy Center	696,245	694,563	692,920	691,277	689,691	688,106	4,152,802
39 Martin Next Generation Solar Energy Center	3,999,245	3,989,515	3,986,148	3,982,763	3,972,996	3,973,970	23,904,638
41 Manatee Temporary Heating System Project	78,854	78,787	78,720	78,653	78,586	78,519	472,117
42 Turkey Point Cooling Canal Monitoring Plan	33,480	33,437	33,394	33,351	33,308	33,265	200,236
44 Martin Plant Barley Barber Swamp Iron Mitigation Project	1,425	1,423	1,421	1,418	1,416	1,414	8,517
45 800 MW Unit ESP Project	172,191	390,287	452,856	477,110	503,380	525,794	2,521,618
2 Total Investment Projects - Recoverable Costs	$13,196,893	$13,406,090	$13,480,739	$13,915,547	$14,350,811	$14,394,758	$82,744,838
3 Recoverable Costs Allocated to Energy	$1,945,798	$1,943,526	$1,942,867	$1,972,860	$2,005,065	$2,007,460	$11,817,576
4 Recoverable Costs Allocated to Demand	$11,251,095	$11,462,564	$11,537,872	$11,942,687	$12,345,746	$12,387,298	$70,927,262
5 Retail Energy Jurisdictional Factor	98.08128%	98.08128%	98.08128%	98.08128%	98.08128%	98.08128%	
6 Retail Demand Jurisdictional Factor	98.01395%	98.01395%	98.01395%	98.01395%	98.01395%	98.01395%	
7 Jurisdictional Energy Recoverable Costs (B)	$1,908,464	$1,906,235	$1,905,589	$1,935,007	$1,966,593	$1,968,942	$11,590,830
8 Jurisdictional Demand Recoverable Costs (C)	$11,027,643	$11,234,913	$11,308,725	$11,705,500	$12,100,554	$12,141,281	$69,518,616
9 Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$12,936,107	$13,141,148	$13,214,314	$13,640,507	$14,067,147	$14,110,223	$81,109,446

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

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Projection Amount for the Period
January 2012 - December 2012

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line # Project #	Estimated JUL	Estimated AUG	Estimated SEP	Estimated OCT	Estimated NOV	Estimated DEC	6-Month Sub-Total	12-Month Total	Method of Classification Demand	Energy
1 Description of Investment Projects (A)										
2 Low NOx Burner Technology	$25,518	$25,360	$25,202	$25,044	$24,885	$24,727	$150,736	$307,169		$307,169
3b Continuous Emission Monitoring Systems	58,973	58,766	58,559	59,901	61,239	61,025	358,464	693,652		693,652
4b Clean Closure Equivalency	167	167	166	166	165	165	996	2,012	1,857	155
5b Maintenance of Stationary Above Ground Fuel Storage Tanks	84,170	83,982	86,080	88,174	87,978	87,782	518,166	1,027,134	948,123	79,011
7 Relocate Turbine Lube Oil Underground Piping to Above Ground	128	127	127	126	126	125	760	1,539	1,420	119
8b Oil Spill Cleanup/Response Equipment	11,314	11,592	12,099	12,040	11,899	11,758	70,703	141,165	130,306	10,859
10 Relocate Storm Water Runoff	684	683	681	680	679	677	4,084	8,218	7,586	632
NA SO2 Allowances-Negative Return on Investment	(11,819)	(11,416)	(11,014)	(10,612)	(10,210)	(9,808)	(64,879)	(144,054)		(144,054)
12 Scherer Discharge Pipeline	4,613	4,599	4,586	4,573	4,560	4,547	27,479	55,428	51,165	4,263
20 Wastewater Discharge Elimination &Reuse	10,200	10,180	10,161	10,142	10,122	10,103	60,908	122,512	113,088	9,424
21 St. Lucie Turtle Net	8,801	8,797	8,792	8,788	8,784	20,221	64,183	117,077	108,071	9,006
22 Pipeline Integrity Management	11,870	11,852	11,835	11,818	11,801	15,438	74,614	146,193	134,947	11,246
23 SPCC - Spill Prevention, Control & Countermeasures	169,281	169,045	168,831	168,659	168,465	169,228	1,013,509	2,032,074	1,875,761	156,313
24 Manatee Reburn	274,057	273,507	272,956	272,406	271,855	271,305	1,636,085	3,291,987		3,291,987
25 Pt. Everglades ESP Technology	670,660	669,445	668,230	667,015	665,800	664,586	4,005,736	8,055,204		8,055,204
26 UST Removal / Replacement	1,012	1,010	1,009	1,007	1,006	1,004	6,048	12,154	11,219	935
31 CAIR Compliance	5,154,002	5,161,683	5,169,915	5,179,185	5,186,840	5,205,859	31,057,484	58,932,516	54,399,245	4,533,271
33 CAMR Compliance	1,042,040	1,040,294	1,038,546	1,036,792	1,035,036	1,033,331	6,226,039	12,514,950	11,552,261	962,689
35 Martin Plant Drinking Water System Compliance	2,165	2,162	2,158	2,155	2,152	2,148	12,939	25,997	23,998	1,999
36 Low-Level Radioactive Waste Storage	126,946	126,784	126,622	126,460	126,298	126,136	759,247	1,305,096	1,204,704	100,392
37 DeSoto Next Generation Solar Energy Center	1,457,795	1,454,155	1,450,515	1,446,875	1,443,067	1,439,261	8,691,668	17,511,856	16,164,790	1,347,066
38 Space Coast Next Generation Solar Energy Center	686,423	684,741	683,058	681,376	679,694	678,011	4,093,303	8,246,105	7,611,789	634,316
39 Martin Next Generation Solar Energy Center	3,974,922	3,965,112	3,955,301	3,945,490	3,935,680	3,926,137	23,702,643	47,607,281	43,945,182	3,662,099
41 Manatee Temporary Heating System Project	78,451	78,384	78,317	78,250	78,183	78,116	469,703	941,820	869,372	72,448
42 Turkey Point Cooling Canal Monitoring Plan	33,222	33,179	33,136	33,093	33,050	33,007	198,688	398,925	368,238	30,687
44 Martin Plant Barley Barber Swamp Iron Mitigation Project	1,412	1,410	1,408	1,406	1,404	1,402	8,443	16,960	16,960	
45 800 MW Unit ESP Project	600,500	681,264	734,607	806,766	850,643	876,970	4,550,750	7,072,368	7,072,368	
2 Total Investment Projects - Recoverable Costs	$14,477,509	$14,546,864	$14,591,886	$14,657,776	$14,691,201	$14,733,263	$87,698,499	$170,443,338	$146,612,450	$23,830,888
3 Recoverable Costs Allocated to Energy	$ 2,006,482	$ 2,004,010	$ 2,001,774	$ 2,001,127	$ 2,000,154	$ 1,999,762	$ 12,013,309	$ 23,830,888		
4 Recoverable Costs Allocated to Demand	$ 12,471,027	$ 12,542,855	$ 12,590,111	$ 12,656,649	$ 12,691,047	$ 12,733,500	$ 75,685,190	$ 146,612,450		
5 Retail Energy Jurisdictional Factor	98.08128%	98.08128%	98.08128%	98.08128%	98.08128%	98.08128%				
6 Retail Demand Jurisdictional Factor	98.01395%	98.01395%	98.01395%	98.01395%	98.01395%	98.01395%				
7 Jurisdictional Energy Recoverable Costs (B)	$ 1,967,983	$1,965,558	$1,963,366	$1,962,731	$1,961,777	$1,961,392	$11,782,807	$23,373,637		
8 Jurisdictional Demand Recoverable Costs (C)	$ 12,223,347	$12,293,748	$12,340,066	$12,405,282	$12,438,998	$12,480,607	$74,182,048	$143,700,664		
9 Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$14,191,330	$14,259,306	$14,303,432	$14,368,013	$14,400,775	$14,441,999	$85,964,855	$167,074,301		

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

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

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

Line	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1. Investments								
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0
d. Other								
2. Plant-In-Service/Depreciation Base (A)	$9,896,803	9,896,803	9,896,803	9,896,803	9,896,803	9,896,803	9,896,803	n/a
3. Less: Accumulated Depreciation	$9,050,547	9,070,322	9,090,098	9,109,873	9,129,648	9,149,423	9,169,199	n/a
4. CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5. Net Investment (Lines 2 - 3 + 4)	$846,256	$826,481	$806,705	$786,930	$767,155	$747,380	$727,604	n/a
6. Average Net Investment		836,368	816,593	796,818	777,042	757,267	737,492	n/a
7. Return on Average Net Investment								
a. Equity Component grossed up for taxes (B)		5,335	5,209	5,083	4,957	4,831	4,704	$30,119
b. Debt Component (Line 6 x debt rate x 1/12) (C)		1,357	1,325	1,293	1,261	1,229	1,197	$7,662
8. Investment Expenses								
a. Depreciation (E)		19,775	19,775	19,775	19,775	19,775	19,775	$118,652
b. Amortization (F)								
c. Dismantlement (G)								
d. Property Expenses								
e. Other								
9. Total System Recoverable Expenses (Lines 7 & 8)		$26,468	$26,310	$26,151	$25,993	$25,835	$25,677	$156,433

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$9,896,803	9,896,803	9,896,803	9,896,803	9,896,803	9,896,803	9,896,803	n/a
3.	Less: Accumulated Depreciation	$9,169,199	9,188,974	9,208,749	9,228,525	9,248,300	9,268,075	9,287,850	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$727,604	$707,829	$688,054	$668,278	$648,503	$628,728	$608,952	n/a
6.	Average Net Investment		717,717	697,941	678,166	658,391	638,615	618,840	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		4,578	4,452	4,326	4,200	4,074	3,948	55,697
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		1,165	1,133	1,101	1,068	1,036	1,004	14,169
8.	Investment Expenses								
	a. Depreciation (E)		19,775	19,775	19,775	19,775	19,775	19,775	237,303
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$25,518	$25,360	$25,202	$25,044	$24,885	$24,727	$307,169

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

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

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$455,212	$0	$455,212
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$10,232,475	10,232,475	10,232,475	10,232,475	10,232,475	10,687,687	10,687,687	n/a
3.	Less: Accumulated Depreciation	$6,385,777	6,410,179	6,434,581	6,458,982	6,483,384	6,508,506	6,534,348	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$3,846,698	$3,822,296	$3,797,895	$3,773,493	$3,749,091	$4,179,182	$4,153,339	n/a
6.	Average Net Investment		3,834,497	3,810,095	3,785,694	3,761,292	3,964,137	4,166,261	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		24,460	24,305	24,149	23,993	25,287	26,577	$148,771
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		6,223	6,183	6,143	6,104	6,433	6,761	$37,847
8.	Investment Expenses								
	a. Depreciation (E)		24,402	24,402	24,402	24,402	25,122	25,842	$148,570
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$55,084	$54,889	$54,694	$54,499	$56,842	$59,180	$335,188

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$269,620	$0	$0	$724,832
	c. Retirements		-	$0	$0	$0	$0	$0	$0
	d. Other		-	-	-	-	-	-	
2.	Plant-In-Service/Depreciation Base (A)	$10,687,687	10,687,687	10,687,687	10,687,687	10,957,307	10,957,307	10,957,307	n/a
3.	Less: Accumulated Depreciation	$6,534,348	6,560,190	6,586,032	6,611,874	6,638,188	6,664,974	6,691,760	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$4,153,339	$4,127,497	$4,101,655	$4,075,813	$4,319,119	$4,292,333	$4,265,548	n/a
6.	Average Net Investment		4,140,418	4,114,576	4,088,734	4,197,466	4,305,726	4,278,940	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		26,412	26,247	26,082	26,776	27,466	27,295	309,049
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		6,719	6,677	6,635	6,812	6,987	6,944	78,621
8.	Investment Expenses								
	a. Depreciation (E)		25,842	25,842	25,842	26,314	26,786	26,786	305,982
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$58,973	$58,766	$58,559	$59,901	$61,239	$61,025	$693,652

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

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

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$41,612	41,612	41,612	41,612	41,612	41,612	41,612	n/a
3.	Less: Accumulated Depreciation	$28,925	28,995	29,064	29,134	29,203	29,273	29,342	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$12,686	$12,617	$12,547	$12,478	$12,408	$12,339	$12,269	n/a
6.	Average Net Investment		12,652	12,582	12,513	12,443	12,374	12,304	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		81	80	80	79	79	78	$478
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		21	20	20	20	20	20	$121
8.	Investment Expenses								
	a. Depreciation (E)		70	70	70	70	70	70	$417
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$171	$170	$170	$169	$169	$168	$1,016

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$41,612	41,612	41,612	41,612	41,612	41,612	41,612	n/a
3.	Less: Accumulated Depreciation	$29,342	29,412	29,481	29,551	29,620	29,690	29,759	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$12,269	$12,200	$12,130	$12,061	$11,991	$11,922	$11,852	n/a
6.	Average Net Investment		12,235	12,165	12,096	12,026	11,956	11,887	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		78	78	77	77	76	76	939
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		20	20	20	20	19	19	239
8.	Investment Expenses								
	a. Depreciation (E)		70	70	70	70	70	70	834
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$167	$167	$166	$166	$165	$165	$2,012

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

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

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$11,737,140	11,737,140	11,737,140	11,737,140	11,737,140	11,737,140	11,737,140	n/a
3.	Less: Accumulated Depreciation	$4,001,542	4,025,035	4,048,528	4,072,021	4,095,514	4,119,007	4,142,501	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$7,735,599	$7,712,105	$7,688,612	$7,665,119	$7,641,626	$7,618,133	$7,594,640	n/a
6.	Average Net Investment		7,723,852	7,700,359	7,676,866	7,653,373	7,629,879	7,606,386	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		49,270	49,121	48,971	48,821	48,671	48,521	$293,375
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		12,534	12,496	12,458	12,420	12,382	12,344	$74,634
8.	Investment Expenses								
	a. Depreciation (E)		23,493	23,493	23,493	23,493	23,493	23,493	$140,959
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$85,298	$85,110	$84,922	$84,734	$84,546	$84,358	$508,967

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$450,000	$0	$0	$0	$450,000
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$11,737,140	11,737,140	11,737,140	12,187,140	12,187,140	12,187,140	12,187,140	n/a
3.	Less: Accumulated Depreciation	$4,142,501	4,165,994	4,189,487	4,213,468	4,237,936	4,262,404	4,286,872	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$7,594,640	$7,571,147	$7,547,653	$7,973,673	$7,949,205	$7,924,736	$7,900,268	n/a
6.	Average Net Investment		7,582,893	7,559,400	7,760,663	7,961,439	7,936,971	7,912,502	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		48,371	48,221	49,505	50,786	50,630	50,474	591,362
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		12,306	12,267	12,594	12,920	12,880	12,840	150,441
8.	Investment Expenses								
	a. Depreciation (E)		23,493	23,493	23,981	24,468	24,468	24,468	285,330
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$84,170	$83,982	$86,080	$88,174	$87,978	$87,782	$1,027,134

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

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

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$31,030	31,030	31,030	31,030	31,030	31,030	31,030	n/a
3.	Less: Accumulated Depreciation	$22,388	22,450	22,512	22,574	22,636	22,698	22,761	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$8,642	$8,580	$8,518	$8,456	$8,394	$8,332	$8,269	n/a
6.	Average Net Investment		8,611	8,549	8,487	8,425	8,363	8,301	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		55	55	54	54	53	53	$324
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		14	14	14	14	14	13	$82
8.	Investment Expenses								
	a. Depreciation (E)		62	62	62	62	62	62	$372
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$131	$130	$130	$129	$129	$128	$778

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$31,030	31,030	31,030	31,030	31,030	31,030	31,030	n/a
3.	Less: Accumulated Depreciation	$22,761	22,823	22,885	22,947	23,009	23,071	23,133	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$8,269	$8,207	$8,145	$8,083	$8,021	$7,959	$7,897	n/a
6.	Average Net Investment		8,238	8,176	8,114	8,052	7,990	7,928	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		53	52	52	51	51	51	633
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		13	13	13	13	13	13	161
8.	Investment Expenses								
	a. Depreciation (E)		62	62	62	62	62	62	745
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$128	$127	$127	$126	$126	$125	$1,539

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

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

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		($58,779)	($1,621)	$0	$0	$0	$0	($60,400)
	c. Retirements		($58,779)	($1,621)	$0	$0	$0	$0	($60,400)
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$946,785	888,006	886,385	886,385	886,385	886,385	886,385	n/a
3.	Less: Accumulated Depreciation	$341,766	290,067	295,517	302,588	309,658	316,729	323,799	n/a
4.	CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$605,019	$597,939	$590,868	$583,798	$576,727	$569,656	$562,586	n/a
6.	Average Net Investment		601,479	594,403	587,333	580,262	573,192	566,121	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		3,837	3,792	3,747	3,701	3,656	3,611	$22,344
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		976	965	953	942	930	919	$5,684
8.	Investment Expenses								
	a. Depreciation (E)		7,080	7,071	7,071	7,071	7,071	7,071	$42,433
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$11,893	$11,827	$11,770	$11,714	$11,657	$11,601	$70,462

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

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 2012

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$8,227	($2,600)	$0	$0	($13,891)	($68,664)
	c. Retirements		$0	($38,773)	($2,600)	$0	$0	($13,891)	($115,664)
	d. Other								0
2.	Plant-In-Service/Depreciation Base (A)	$886,385	886,385	894,612	892,012	892,012	892,012	878,121	n/a
3.	Less: Accumulated Depreciation	$323,799	330,639	298,851	303,613	310,974	318,253	311,558	n/a
4.	CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$562,586	$555,746	$595,761	$588,399	$581,038	$573,759	$566,563	n/a
6.	Average Net Investment		559,166	575,753	592,080	584,719	577,399	570,161	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		3,567	3,673	3,777	3,730	3,683	3,637	44,411
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		907	934	961	949	937	925	11,298
8.	Investment Expenses								
	a. Depreciation (E)		6,840	6,985	7,361	7,361	7,279	7,196	85,456
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$11,314	$11,592	$12,099	$12,040	$11,899	$11,758	$141,165

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.

(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.

(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

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

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$117,794	117,794	117,794	117,794	117,794	117,794	117,794	n/a
3.	Less: Accumulated Depreciation	$53,226	53,403	53,579	53,756	53,933	54,109	54,286	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$64,568	$64,391	$64,215	$64,038	$63,861	$63,684	$63,508	n/a
6.	Average Net Investment		64,480	64,303	64,126	63,950	63,773	63,596	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		411	410	409	408	407	406	$2,451
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		105	104	104	104	103	103	$624
8.	Investment Expenses								
	a. Depreciation (E)		177	177	177	177	177	177	$1,060
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$693	$691	$690	$688	$687	$686	$4,135

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$117,794	117,794	117,794	117,794	117,794	117,794	117,794	n/a
3.	Less: Accumulated Depreciation	$54,286	54,463	54,639	54,816	54,993	55,169	55,346	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$63,508	$63,331	$63,154	$62,978	$62,801	$62,624	$62,448	n/a
6.	Average Net Investment		63,419	63,243	63,066	62,889	62,713	62,536	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		405	403	402	401	400	399	4,861
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		103	103	102	102	102	101	1,237
8.	Investment Expenses								
	a. Depreciation (E)		177	177	177	177	177	177	2,120
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$684	$683	$681	$680	$679	$677	$8,218

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

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

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$864,260	864,260	864,260	864,260	864,260	864,260	864,260	n/a
3.	Less: Accumulated Depreciation	$481,213	482,845	484,477	486,110	487,742	489,374	491,007	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$383,048	$381,416	$379,783	$378,151	$376,519	$374,886	$373,254	n/a
6.	Average Net Investment		382,232	380,599	378,967	377,335	375,702	374,070	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		2,438	2,428	2,417	2,407	2,397	2,386	$14,473
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		620	618	615	612	610	607	$3,682
8.	Investment Expenses								
	a. Depreciation (E)		1,632	1,632	1,632	1,632	1,632	1,632	$9,794
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$4,691	$4,678	$4,665	$4,652	$4,639	$4,626	$27,949

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$864,260	864,260	864,260	864,260	864,260	864,260	864,260	n/a
3.	Less: Accumulated Depreciation	$491,007	492,639	494,271	495,904	497,536	499,168	500,801	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$373,254	$371,622	$369,989	$368,357	$366,725	$365,092	$363,460	n/a
6.	Average Net Investment		372,438	370,805	369,173	367,541	365,908	364,276	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		2,376	2,365	2,355	2,345	2,334	2,324	28,572
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		604	602	599	596	594	591	7,269
8.	Investment Expenses								
	a. Depreciation (E)		1,632	1,632	1,632	1,632	1,632	1,632	19,588
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$4,613	$4,599	$4,586	$4,573	$4,560	$4,547	$55,428

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.

(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.

(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

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

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$1,234,108	1,234,108	1,234,108	1,234,108	1,234,108	1,234,108	1,234,108	n/a
3.	Less: Accumulated Depreciation	$246,053	248,472	250,891	253,310	255,730	258,149	260,568	n/a
4.	CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$988,055	$985,636	$983,216	$980,797	$978,378	$975,958	$973,539	n/a
6.	Average Net Investment		986,845	984,426	982,007	979,587	977,168	974,749	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		6,295	6,280	6,264	6,249	6,233	6,218	$37,539
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		1,601	1,598	1,594	1,590	1,586	1,582	$9,550
8.	Investment Expenses								
	a. Depreciation (E)		2,419	2,419	2,419	2,419	2,419	2,419	$14,516
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$10,316	$10,296	$10,277	$10,258	$10,238	$10,219	$61,605

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

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 2012

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$1,234,108	1,234,108	1,234,108	1,234,108	1,234,108	1,234,108	1,234,108	n/a
3.	Less: Accumulated Depreciation	$260,568	262,988	265,407	267,826	270,246	272,665	275,084	n/a
4.	CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$973,539	$971,120	$968,701	$966,281	$963,862	$961,443	$959,023	n/a
6.	Average Net Investment		972,329	969,910	967,491	965,072	962,652	960,233	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		6,202	6,187	6,172	6,156	6,141	6,125	74,522
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		1,578	1,574	1,570	1,566	1,562	1,558	18,958
8.	Investment Expenses								
	a. Depreciation (E)		2,419	2,419	2,419	2,419	2,419	2,419	29,032
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$10,200	$10,180	$10,161	$10,142	$10,122	$10,103	$122,512

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

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

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$352,942	352,942	352,942	352,942	352,942	352,942	352,942	n/a
3.	Less: Accumulated Depreciation	($684,200)	(683,670)	(683,141)	(682,611)	(682,082)	(681,552)	(681,023)	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,037,142	$1,036,612	$1,036,083	$1,035,554	$1,035,024	$1,034,495	$1,033,965	n/a
6.	Average Net Investment		1,036,877	1,036,348	1,035,818	1,035,289	1,034,760	1,034,230	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		6,614	6,611	6,607	6,604	6,601	6,597	$39,635
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		1,683	1,682	1,681	1,680	1,679	1,678	$10,083
8.	Investment Expenses								
	a. Depreciation (E)		529	529	529	529	529	529	$3,176
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$8,826	$8,822	$8,818	$8,814	$8,809	$8,805	$52,894

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.

(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.

(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$2,409,747	$2,409,747
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$352,942	352,942	352,942	352,942	352,942	352,942	2,762,689	n/a
3.	Less: Accumulated Depreciation	($681,023)	(680,494)	(679,964)	(679,435)	(678,905)	(678,376)	(676,039)	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,033,965	$1,033,436	$1,032,907	$1,032,377	$1,031,848	$1,031,318	$3,438,729	n/a
6.	Average Net Investment		1,033,701	1,033,171	1,032,642	1,032,112	1,031,583	2,235,024	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		6,594	6,591	6,587	6,584	6,580	14,257	86,828
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		1,677	1,677	1,676	1,675	1,674	3,627	22,089
8.	Investment Expenses								
	a. Depreciation (E)		529	529	529	529	529	2,337	8,160
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$8,801	$8,797	$8,792	$8,788	$8,784	$20,221	$117,077

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

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

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$1,229,528	1,229,528	1,229,528	1,229,528	1,229,528	1,229,528	1,229,528	n/a
3.	Less: Accumulated Depreciation	$1,076	3,228	5,379	7,531	9,683	11,834	13,986	n/a
4.	CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,228,452	$1,226,300	$1,224,149	$1,221,997	$1,219,845	$1,217,694	$1,215,542	n/a
6.	Average Net Investment		1,227,376	1,225,225	1,223,073	1,220,921	1,218,770	1,216,618	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		7,829	7,816	7,802	7,788	7,775	7,761	$46,771
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		1,992	1,988	1,985	1,981	1,978	1,974	$11,898
8.	Investment Expenses								
	a. Depreciation (E)		2,152	2,152	2,152	2,152	2,152	2,152	$12,910
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$11,973	$11,956	$11,938	$11,921	$11,904	$11,887	$71,579

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$750,000	$750,000
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$1,229,528	1,229,528	1,229,528	1,229,528	1,229,528	1,229,528	1,979,528	n/a
3.	Less: Accumulated Depreciation	$13,986	16,138	18,289	20,441	22,593	24,744	27,552	n/a
4.	CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,215,542	$1,213,390	$1,211,239	$1,209,087	$1,206,935	$1,204,784	$1,951,976	n/a
6.	Average Net Investment		1,214,466	1,212,315	1,210,163	1,208,011	1,205,860	1,578,380	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		7,747	7,733	7,720	7,706	7,692	10,068	95,437
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		1,971	1,967	1,964	1,960	1,957	2,561	24,279
8.	Investment Expenses								
	a. Depreciation (E)		2,152	2,152	2,152	2,152	2,152	2,808	26,476
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$11,870	$11,852	$11,835	$11,818	$11,801	$15,438	$146,193

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

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

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$12,500	$92,500	$12,500	$12,500	$12,500	$12,500	$155,000
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$19,662,658	19,675,158	19,767,658	19,780,158	19,792,658	19,805,158	19,817,658	n/a
3.	Less: Accumulated Depreciation	$3,317,315	3,356,277	3,395,335	3,434,490	3,473,665	3,512,860	3,552,074	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$16,345,343	$16,318,881	$16,372,322	$16,345,667	$16,318,993	$16,292,298	$16,265,584	n/a
6.	Average Net Investment		16,332,112	16,345,602	16,358,995	16,332,330	16,305,645	16,278,941	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		104,183	104,269	104,354	104,184	104,014	103,843	$624,846
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		26,504	26,526	26,547	26,504	26,461	26,417	$158,959
8.	Investment Expenses								
	a. Depreciation (E)		38,962	39,059	39,155	39,175	39,195	39,214	$234,760
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$169,648	$169,853	$170,056	$169,863	$169,669	$169,475	$1,018,565

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$12,500	$12,500	$9,950	$12,500	$12,500	$212,500	$427,450
	c. Retirements		$0	$0	($7,065)	$0	$0	$0	($7,065)
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$19,817,658	19,830,158	19,842,658	19,852,608	19,865,108	19,877,608	20,090,108	n/a
3.	Less: Accumulated Depreciation	$3,552,074	3,591,309	3,630,521	3,662,649	3,701,866	3,741,103	3,780,518	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$16,265,584	$16,238,849	$16,212,137	$16,189,959	$16,163,242	$16,136,505	$16,309,590	n/a
6.	Average Net Investment		16,252,216	16,225,493	16,201,048	16,176,600	16,149,874	16,223,048	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		103,673	103,502	103,346	103,191	103,020	103,487	1,245,065
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		26,374	26,331	26,291	26,251	26,208	26,327	316,741
8.	Investment Expenses								
	a. Depreciation (E)		39,234	39,212	39,193	39,217	39,237	39,415	470,268
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$169,281	$169,045	$168,831	$168,659	$168,465	$169,228	$2,032,074

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

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

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$31,749,547	31,749,547	31,749,547	31,749,547	31,749,547	31,749,547	31,749,547	n/a
3.	Less: Accumulated Depreciation	$5,649,884	5,718,674	5,787,465	5,856,256	5,925,046	5,993,837	6,062,628	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$26,099,663	$26,030,872	$25,962,082	$25,893,291	$25,824,500	$25,755,710	$25,686,919	n/a
6.	Average Net Investment		26,065,268	25,996,477	25,927,686	25,858,896	25,790,105	25,721,314	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		166,270	165,831	165,393	164,954	164,515	164,076	$991,040
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		42,299	42,187	42,075	41,964	41,852	41,741	$252,118
8.	Investment Expenses								
	a. Depreciation (E)		68,791	68,791	68,791	68,791	68,791	68,791	$412,744
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$277,360	$276,809	$276,259	$275,708	$275,158	$274,607	$1,655,902

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$31,749,547	31,749,547	31,749,547	31,749,547	31,749,547	31,749,547	31,749,547	n/a
3.	Less: Accumulated Depreciation	$6,062,628	6,131,418	6,200,209	6,269,000	6,337,791	6,406,581	6,475,372	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$25,686,919	$25,618,128	$25,549,337	$25,480,547	$25,411,756	$25,342,965	$25,274,175	n/a
6.	Average Net Investment		25,652,524	25,583,733	25,514,942	25,446,151	25,377,361	25,308,570	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		163,637	163,199	162,760	162,321	161,882	161,443	1,966,282
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		41,629	41,517	41,406	41,294	41,182	41,071	500,217
8.	Investment Expenses								
	a. Depreciation (E)		68,791	68,791	68,791	68,791	68,791	68,791	825,488
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$274,057	$273,507	$272,956	$272,406	$271,855	$271,305	$3,291,987

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

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

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$81,901,169	81,901,169	81,901,169	81,901,169	81,901,169	81,901,169	81,901,169	n/a
3.	Less: Accumulated Depreciation	$16,073,562	16,225,378	16,377,195	16,529,011	16,680,828	16,832,645	16,984,461	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$65,827,608	$65,675,791	$65,523,975	$65,372,158	$65,220,341	$65,068,525	$64,916,708	n/a
6.	Average Net Investment		65,751,699.53	65,599,883	65,448,066	65,296,250	65,144,433	64,992,617	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		419,430.01	418,462	417,493	416,525	415,556	414,588	$2,502,053
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		106,702	106,455	106,209	105,963	105,716	105,470	$636,516
8.	Investment Expenses								
	a. Depreciation (E)		151,817	151,817	151,817	151,817	151,817	151,817	$910,900
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$677,948.47	$676,734	$675,519	$674,304	$673,089	$671,874	$4,049,469

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$81,901,169	81,901,169	81,901,169	81,901,169	81,901,169	81,901,169	81,901,169	n/a
3.	Less: Accumulated Depreciation	$16,984,461	17,136,278	17,288,094	17,439,911	17,591,728	17,743,544	17,895,361	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$64,916,708	$64,764,892	$64,613,075	$64,461,258	$64,309,442	$64,157,625	$64,005,809	n/a
6.	Average Net Investment		64,840,800	64,688,983	64,537,167	64,385,350	64,233,534	64,081,717	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		413,619	412,651	411,683	410,714	409,746	408,777	4,969,243
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		105,224	104,977	104,731	104,485	104,238	103,992	1,264,162
8.	Investment Expenses								
	a. Depreciation (E)		151,817	151,817	151,817	151,817	151,817	151,817	1,821,799
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$670,660	$669,445	$668,230	$667,015	$665,800	$664,586	$8,055,204

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

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

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$115,447	115,447	115,447	115,447	115,447	115,447	115,447	n/a
3.	Less: Accumulated Depreciation	$12,909	13,111	13,313	13,515	13,717	13,919	14,121	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$102,538	$102,336	$102,134	$101,932	$101,730	$101,528	$101,326	n/a
6.	Average Net Investment		102,437	102,235	102,033	101,831	101,629	101,427	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		653	652	651	650	648	647	$3,901
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		166	166	166	165	165	165	$992
8.	Investment Expenses								
	a. Depreciation (E)		202	202	202	202	202	202	$1,212
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,022	$1,020	$1,018	$1,017	$1,015	$1,014	$6,106

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

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								
2.	Plant-In-Service/Depreciation Base (A)	$115,447	115,447	115,447	115,447	115,447	115,447	115,447	n/a
3.	Less: Accumulated Depreciation	$14,121	14,323	14,525	14,727	14,929	15,131	15,333	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$101,326	$101,124	$100,922	$100,720	$100,518	$100,316	$100,113	n/a
6.	Average Net Investment		101,225	101,023	100,821	100,619	100,417	100,214	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		646	644	643	642	641	639	7,756
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		164	164	164	163	163	163	1,973
8.	Investment Expenses								
	a. Depreciation (E)		202	202	202	202	202	202	2,424
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,012	$1,010	$1,009	$1,007	$1,006	$1,004	$12,154

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

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

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$3,230,504	$3,555,876	$3,303,064	$3,886,023	$3,250,791	$17,226,258
	b. Clearings to Plant		$0	$0	$0	$340,445,221	$3,886,023	$3,250,791	$347,582,035
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$169,108,395	169,108,395	169,108,395	169,108,395	509,553,616	513,439,639	516,690,430	n/a
3.	Less: Accumulated Depreciation	$9,197,716	9,565,608	9,933,500	10,301,393	11,038,101	12,147,834	13,265,299	n/a
4.	CWIP - Non Interest Bearing	$330,355,777	330,355,777	333,586,281	337,142,157	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$490,266,457	$489,898,564	$492,761,176	$495,949,159	$498,515,515	$501,291,805	$503,425,131	n/a
6.	Average Net Investment		490,082,510	491,329,870	494,355,168	497,232,337	499,903,660	502,358,468	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		3,126,236	3,134,193	3,153,491	3,171,844	3,188,885	3,204,544	$18,979,193
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		795,306	797,330	802,240	806,909	811,244	815,227	$4,828,255
8.	Investment Expenses								
	a. Depreciation (E)		367,892	367,892	367,893	736,708	1,109,734	1,117,465	$4,067,584
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$4,289,434	$4,299,415	$4,323,623	$4,715,461	$5,109,862	$5,137,236	$27,875,032

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.

(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.

(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

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		$1,809,877	$1,470,921	$1,924,068	$1,681,018	$1,612,335	$3,923,528	$29,648,005
	b. Clearings to Plant		$1,809,877	$1,470,921	$1,924,068	$1,681,018	$1,612,335	$3,923,528	$360,003,782
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$516,690,430	518,500,307	519,971,228	521,895,296	523,576,314	525,188,649	529,112,177	n/a
3.	Less: Accumulated Depreciation	$13,265,299	14,388,247	15,514,748	16,644,928	17,779,013	18,916,666	20,060,316	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$503,425,131	$504,112,060	$504,456,480	$505,250,368	$505,797,301	$506,271,983	$509,051,861	n/a
6.	Average Net Investment		503,768,596	504,284,270	504,853,424	505,523,835	506,034,642	507,661,922	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		3,213,539	3,216,829	3,220,459	3,224,736	3,227,994	3,238,375	38,321,125
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		817,516	818,353	819,276	820,364	821,193	823,834	9,748,790
8.	Investment Expenses								
	a. Depreciation (E)		1,122,947	1,126,502	1,130,180	1,134,085	1,137,653	1,143,650	10,862,600
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$5,154,002	$5,161,683	$5,169,915	$5,179,185	$5,186,840	$5,205,859	$58,932,516

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

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

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$10,978	$12,428	$11,723	$11,392	$11,309	$57,830
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$107,265,404	107,265,404	107,276,382	107,288,810	107,300,533	107,311,925	107,323,234	n/a
3.	Less: Accumulated Depreciation	$4,653,786	4,886,194	5,118,614	5,351,060	5,583,532	5,816,029	6,048,550	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$102,611,618	$102,379,210	$102,157,767	$101,937,750	$101,717,001	$101,495,896	$101,274,684	n/a
6.	Average Net Investment		102,495,414	102,268,489	102,047,759	101,827,375	101,606,449	101,385,290	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		653,818	652,371	650,963	649,557	648,147	646,737	$3,901,592
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		166,330	165,961	165,603	165,245	164,887	164,528	$992,554
8.	Investment Expenses								
	a. Depreciation (E)		232,408	232,420	232,446	232,472	232,497	232,521	$1,394,764
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,052,556	$1,050,752	$1,049,011	$1,047,274	$1,045,531	$1,043,786	$6,288,911

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$11,309	$11,226	$10,895	$10,356	$10,315	$20,464	$132,395
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$107,323,234	107,334,543	107,345,769	107,356,664	107,367,020	107,377,335	107,397,799	n/a
3.	Less: Accumulated Depreciation	$6,048,550	6,281,096	6,513,666	6,746,261	6,978,878	7,211,518	7,444,191	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$101,274,684	$101,053,447	$100,832,103	$100,610,403	$100,388,142	$100,165,817	$99,953,608	n/a
6.	Average Net Investment		101,164,065	100,942,775	100,721,253	100,499,273	100,276,980	100,059,713	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		645,325	643,914	642,501	641,085	639,667	638,281	7,752,364
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		164,169	163,810	163,450	163,090	162,729	162,377	1,972,180
8.	Investment Expenses								
	a. Depreciation (E)		232,546	232,570	232,594	232,617	232,640	232,673	2,790,405
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,042,040	$1,040,294	$1,038,546	$1,036,792	$1,035,036	$1,033,331	$12,514,950

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

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

Line	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1. Investments								
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0
d. Other								
2. Plant-In-Service/Depreciation Base (A)	$235,391	235,391	235,391	235,391	235,391	235,391	235,391	n/a
3. Less: Accumulated Depreciation	$13,654	14,065	14,477	14,889	15,301	15,713	16,125	n/a
4. CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5. Net Investment (Lines 2 - 3 + 4)	$221,738	$221,326	$220,914	$220,502	$220,090	$219,678	$219,266	n/a
6. Average Net Investment		221,532	221,120	220,708	220,296	219,884	219,472	n/a
7. Return on Average Net Investment								
a. Equity Component grossed up for taxes (B)		1,413	1,411	1,408	1,405	1,403	1,400	$8,439
b. Debt Component (Line 6 x debt rate x 1/12) (C)		360	359	358	357	357	356	$2,147
8. Investment Expenses								
a. Depreciation (E)		412	412	412	412	412	412	$2,472
b. Amortization (F)								
c. Dismantlement (G)								
d. Property Expenses								
e. Other								
9. Total System Recoverable Expenses (Lines 7 & 8)		$2,185	$2,181	$2,178	$2,175	$2,171	$2,168	$13,058

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$235,391	235,391	235,391	235,391	235,391	235,391	235,391	n/a
3.	Less: Accumulated Depreciation	$16,125	16,537	16,949	17,361	17,773	18,185	18,597	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$219,266	$218,854	$218,442	$218,030	$217,619	$217,207	$216,795	n/a
6.	Average Net Investment		219,060	218,648	218,236	217,824	217,413	217,001	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		1,397	1,395	1,392	1,390	1,387	1,384	16,784
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		355	355	354	353	353	352	4,270
8.	Investment Expenses								
	a. Depreciation (E)		412	412	412	412	412	412	4,943
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$2,165	$2,162	$2,158	$2,155	$2,152	$2,148	$25,997

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Low Level Rad Waste - LLW (Project No. 36)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$6,577,368	$0	$0	$6,577,368
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$6,926,842	6,926,842	6,926,842	6,926,842	13,504,210	13,504,210	13,504,210	n/a
3.	Less: Accumulated Depreciation	$73,824	84,214	94,605	104,995	120,318	140,575	160,831	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$6,853,017	$6,842,627	$6,832,237	$6,821,847	$13,383,891	$13,363,635	$13,343,379	n/a
6.	Average Net Investment		6,847,822	6,837,432	6,827,042	10,102,869	13,373,763	13,353,507	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		43,682	43,616	43,550	64,446	85,311	85,182	$365,787
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		11,113	11,096	11,079	16,395	21,703	21,670	$93,055
8.	Investment Expenses								
	a. Depreciation (E)		10,390	10,390	10,390	15,323	20,256	20,256	$87,007
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$65,185	$65,102	$65,019	$96,164	$127,270	$127,108	$545,849

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Low Level Rad Waste - LLW (Project No. 36)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$6,577,368
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$13,504,210	13,504,210	13,504,210	13,504,210	13,504,210	13,504,210	13,504,210	n/a
3.	Less: Accumulated Depreciation	$160,831	181,087	201,343	221,600	241,856	262,112	282,369	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$13,343,379	$13,323,122	$13,302,866	$13,282,610	$13,262,353	$13,242,097	$13,221,841	n/a
6.	Average Net Investment		13,333,251	13,312,994	13,292,738	13,272,482	13,252,225	13,231,969	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		85,053	84,924	84,794	84,665	84,536	84,407	874,166
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		21,637	21,604	21,571	21,539	21,506	21,473	222,385
8.	Investment Expenses								
	a. Depreciation (E)		20,256	20,256	20,256	20,256	20,256	20,256	208,545
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$126,946	$126,784	$126,622	$126,460	$126,298	$126,136	$1,305,096

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Desoto Next Generation Solar Energy Center (Project No. 37)
(in Dollars)

Line			Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments									
	a.	Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b.	Clearings to Plant		$0	$0	$47,000	$5,000	$0	$24,000	$76,000
	c.	Retirements		$0	$0	$0	$0	$0	$0	$0
	d.	Other								
2.	Plant-In-Service/Depreciation Base (A)		$153,030,391	153,030,391	153,030,391	153,077,391	153,082,391	153,082,391	153,106,391	n/a
3.	Less: Accumulated Depreciation & Dismantlement		$10,998,580	11,423,428	11,848,276	12,273,217	12,698,256	13,123,302	13,548,381	n/a
4.	CWIP - Non Interest Bearing		$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)		$142,031,811	$141,606,963	$141,182,115	$140,804,175	$140,384,135	$139,959,089	$139,558,010	n/a
6.	Average Net Investment			141,819,387	141,394,539	140,993,145	140,594,155	140,171,612	139,758,550	n/a
	a.	Average ITC Balance		40,709,121	40,587,055	40,464,989	40,342,923	40,220,857	40,098,791	
7.	Return on Average Net Investment (B & C)									
	a.	Equity Component grossed up for taxes (B)		975,248	972,326	969,554	966,797	963,890	961,044	$5,808,860
	b.	Debt Component (Line 6 x debt rate x 1/12) (C)		239,056	238,340	237,661	236,987	236,275	235,578	$1,423,897
8.	Investment Expenses									
	a.	Depreciation (E)		418,789	418,789	418,881	418,980	418,987	419,020	$2,513,447
	b.	Amortization (F)								
	c.	Dismantlement (G)		6,059	6,059	6,059	6,059	6,059	6,059	$36,354
	d.	Property Expenses								
	e.	Amortization ITC Solar		(160,395)	(160,395)	(160,395)	(160,395)	(160,395)	(160,395)	($962,370)
9.	Total System Recoverable Expenses (Lines 7 & 8)			$1,478,757	$1,475,119	$1,471,761	$1,468,429	$1,464,816	$1,461,306	$8,820,188

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.

(B) & (C) For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity.

Debt Component: Return of 1.9473% reflects a 10% ROE. Per FPSC Order No PSC-10-0153-FOF-EI.

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.98% reflects a 10% return on equity.

Debt Component: Return of 2.21% based on the 10% ROE. Per FPSC Order PSC 10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.

(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Desoto Next Generation Solar Energy Center (Project No. 37)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
a.	Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
b.	Clearings to Plant		$0	$0	$0	$0	$0	($12,103)	$63,897
c.	Retirements		$0	$0	$0	$0	$0	($12,103)	($12,103)
d.	Other								
2.	Plant-In-Service/Depreciation Base (A)	$153,106,391	153,106,391	153,106,391	153,106,391	153,106,391	153,106,391	153,094,288	n/a
3.	Less: Accumulated Depreciation & Dismantlement	$13,548,381	13,973,493	14,398,606	14,823,718	15,248,830	15,673,774	16,086,447	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$139,558,010	$139,132,898	$138,707,786	$138,282,673	$137,857,561	$137,432,617	$137,007,841	n/a
6.	Average Net Investment	139,758,550	139,345,454	138,920,342	138,495,229	138,070,117	137,645,089	137,220,229	n/a
a.	Average ITC Balance	40,098,791	39,976,725	39,854,659	39,732,593	39,610,527	39,488,461	39,366,395	
7.	Return on Average Net Investment								
a.	Equity Component grossed up for taxes (B)		958,197	955,274	952,350	949,427	946,504	943,582	11,514,193
b.	Debt Component (Line 6 x debt rate x 1/12) (C)		234,881	234,164	233,448	232,731	232,014	231,298	2,822,433
8.	Investment Expenses								
a.	Depreciation (E)		419,053	419,053	419,053	419,053	418,885	418,717	5,027,262
b.	Amortization (F)								
c.	Dismantlement (G)		6,059	6,059	6,059	6,059	6,059	6,059	$72,708
d.	Property Expenses								
e.	Amortization ITC Solar		(160,395)	(160,395)	(160,395)	(160,395)	(160,395)	(160,395)	($1,924,740)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,457,795	$1,454,155	$1,450,515	$1,446,875	$1,443,067	$1,439,261	$17,511,856

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.

(B) & (C) For solar projects the return on investment calculation is comprised of two parts:
Average Net Investment
Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity
Debt Component: Return of 1.9473% reflects a 10% ROE. Per FPSC Order No PSC-10-0153-FOF-EI.
Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.98% reflects a 10% return on equity
Debt Component: Return of 2.21% based on the 10% ROE. Per FPSC Order PSC 10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.

(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Space Coast Next Generation Solar Energy Center (Project No. 38)
(in Dollars)

Line			Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments									
	a.	Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b.	Clearings to Plant		$0	$0	$2,000	$0	$18,000	$0	$20,000
	c.	Retirements		$0	$0	$0	$0	$0	$0	$0
	d.	Other								
2.	Plant-In-Service/Depreciation Base (A)		$70,630,041	70,630,041	70,630,041	70,632,041	70,632,041	70,650,041	70,650,041	n/a
3.	Less: Accumulated Depreciation & Dismantlement		$4,049,678	4,247,328	4,444,979	4,642,660	4,840,371	5,038,107	5,235,868	n/a
4.	CWIP - Non Interest Bearing		$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)		$66,580,364	$66,382,713	$66,185,063	$65,989,382	$65,791,670	$65,611,934	$65,414,174	n/a
6.	Average Net Investment			66,481,538	66,283,888	66,087,222	65,890,526	65,701,802	65,513,054	n/a
	a.	Average ITC Balance		17,352,939	17,301,750	17,250,561	17,199,372	17,148,183	17,096,994	
7.	Return on Average Net Investment									
	a.	Equity Component grossed up for taxes (B)		454,173	452,823	451,480	450,136	448,844	447,551	$2,705,006
	b.	Debt Component (Line 6 x debt rate x 1/12) (C)		111,685	111,353	111,022	110,692	110,375	110,057	$665,184
8.	Investment Expenses									
	a.	Depreciation (E)		194,739	194,739	194,769	194,800	194,824	194,849	$1,168,718
	b.	Amortization (F)								
	c.	Dismantlement (G)		2,912	2,912	2,912	2,912	2,912	2,912	$17,472
	d.	Property Expenses								
	e.	Amortization ITC Solar		(67,263)	(67,263)	(67,263)	(67,263)	(67,263)	(67,263)	($403,578)
9.	Total System Recoverable Expenses (Lines 7 & 8)			$696,245	$694,563	$692,920	$691,277	$689,691	$688,106	$4,152,802

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.

(B) & (C) For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity

Debt Component: Return of 1.9473% reflects a 10% ROE. Per FPSC Order No PSC-10-0153-FOF-EI.

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.98% reflects a 10% return on equity

Debt Component: Return of 2.21% based on the 10% ROE. Per FPSC Order PSC 10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.

(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Space Coast Next Generation Solar Energy Center (Project No. 38)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
a.	Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
b.	Clearings to Plant		$0	$0	$0	$0	$0	$0	$20,000
c.	Retirements		$0	$0	$0	$0	$0	$0	$0
d.	Other								
2.	Plant-In-Service/Depreciation Base (A)	$70,650,041	70,650,041	70,650,041	70,650,041	70,650,041	70,650,041	70,650,041	n/a
3.	Less: Accumulated Depreciation & Dismantlement	$5,235,868	5,433,628	5,631,389	5,829,150	6,026,910	6,224,671	6,422,431	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$65,414,174	$65,216,413	$65,018,652	$64,820,892	$64,623,131	$64,425,371	$64,227,610	n/a
6.	Average Net Investment		65,315,293	65,117,533	64,919,772	64,722,011	64,524,251	64,326,490	n/a
a.	Average ITC Balance	$17,096,994	17,045,805	16,994,616	16,943,427	16,892,238	16,841,049	16,789,860	
7.	Return on Average Net Investment								
a.	Equity Component grossed up for taxes (B)		446,201	444,850	443,500	442,150	440,799	439,449	5,361,955
b.	Debt Component (Line 6 x debt rate x 1/12) (C)		109,725	109,393	109,061	108,729	108,396	108,064	1,318,552
8.	Investment Expenses								
a.	Depreciation (E)		194,849	194,849	194,849	194,849	194,849	194,849	2,337,810
b.	Amortization (F)								
c.	Dismantlement (G)		2,912	2,912	2,912	2,912	2,912	2,912	34,944
d.	Property Expenses								
e.	Amortization ITC Solar		(67,263)	(67,263)	(67,263)	(67,263)	(67,263)	(67,263)	(807,156)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$686,423	$684,741	$683,058	$681,376	$679,694	$678,011	$8,246,105

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.

(B) & (C) For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity

Debt Component: Return of 1.9473% reflects a 10% ROE. Per FPSC Order No PSC-10-0153-FOF-EI

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.98% reflects a 10% return on equity

Debt Component: Return of 2.21% based on the 10% ROE. Per FPSC Order PSC 10-0153-FOF-EI

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.

(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Martin Next Generation Solar Energy Center (Project No. 39)
(in Dollars)

Line	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1. Investments								
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$1,015,000	$0	$0	$2,000,000	$3,015,000
c. Retirements		$0	$0	$0	$0	$0	$0	$0
d. Other								
2. Plant-In-Service/Depreciation Base (A)	$400,585,919	400,585,919	400,585,919	401,600,919	401,600,919	401,600,919	403,600,919	n/a
3. Less: Accumulated Depreciation & Dismantlement	$14,339,208	15,471,250	16,603,292	17,737,645	18,874,310	20,010,974	21,150,388	n/a
4. CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5. Net Investment (Lines 2 - 3 + 4)	$386,246,711	$385,114,669	$383,982,627	$383,863,274	$382,726,609	$381,589,945	$382,450,531	n/a
6. Average Net Investment		385,680,690	384,548,648	383,922,950	383,294,942	382,158,277	382,020,238	n/a
a. Average ITC Balance		119,225,809	118,882,011	118,538,213	118,194,415	117,850,617	117,506,819	
7. Return on Average Net Investment								
a. Equity Component grossed up for taxes (B)		2,666,973	2,659,156	2,654,568	2,649,966	2,642,119	2,640,643	$15,913,424
b. Debt Component (Line 6 x debt rate x 1/12) (C)		651,981	650,069	648,978	647,884	645,964	645,665	$3,890,541
8. Investment Expenses								
a. Depreciation (E)		1,103,195	1,103,195	1,105,506	1,107,817	1,107,817	1,110,567	$6,638,097
b. Amortization (F)								
c. Dismantlement (G)		28,847	28,847	28,847	28,847	28,847	28,847	$173,082
d. Property Expenses								
e. Amortization ITC Solar		(451,751)	(451,751)	(451,751)	(451,751)	(451,751)	(451,751)	($2,710,506)
9. Total System Recoverable Expenses (Lines 7 & 8)		$3,999,245	$3,989,515	$3,986,148	$3,982,763	$3,972,996	$3,973,970	$23,904,638

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.

(B) & (C) For solar projects the return on investment calculation is comprised of two parts:
Average Net Investment
Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity
Debt Component: Return of 1.9473% reflects a 10% ROE. Per FPSC Order No PSC-10-0153-FOF-EI
Average Unamortized ITC Balance:
Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.98% reflects a 10% return on equity
Debt Component: Return of 2.21% based on the 10% ROE. Per FPSC Order PSC 10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.

(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Martin Next Generation Solar Energy Center (Project No. 39)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
a.	Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
b.	Clearings to Plant		$0	$0	$0	$0	$0	$50,000	$3,065,000
c.	Retirements		$0	$0	$0	$0	$0	$0	$0
d.	Other								
2.	Plant-In-Service/Depreciation Base (A)	$403,600,919	403,600,919	403,600,919	403,600,919	403,600,919	403,600,919	403,650,919	n/a
3.	Less: Accumulated Depreciation & Dismantlement	$21,150,388	22,292,552	23,434,716	24,576,880	25,719,044	26,861,209	28,003,442	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$382,450,531	$381,308,367	$380,166,203	$379,024,039	$377,881,875	$376,739,710	$375,647,477	n/a
6.	Average Net Investment	382,020,238	381,879,449	380,737,285	379,595,121	378,452,957	377,310,792	376,193,594	n/a
a.	Average ITC Balance	$117,506,819	117,163,021	116,819,223	116,475,425	116,131,627	115,787,829	115,444,031	
7.	Return on Average Net Investment								
a.	Equity Component grossed up for taxes (B)		2,639,148	2,631,266	2,623,384	2,615,502	2,607,621	2,599,898	31,630,244
b.	Debt Component (Line 6 x debt rate x 1/12) (C)		645,361	643,432	641,503	639,575	637,646	635,758	7,733,815
8.	Investment Expenses								
a.	Depreciation (E)		1,113,317	1,113,317	1,113,317	1,113,317	1,113,317	1,113,386	13,318,069
b.	Amortization (F)								
c.	Dismantlement (G)		28,847	28,847	28,847	28,847	28,847	28,847	346,164
d.	Property Expenses								
e.	Amortization ITC Solar		(451,751)	(451,751)	(451,751)	(451,751)	(451,751)	(451,751)	(5,421,012)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$3,974,922	$3,965,112	$3,955,301	$3,945,490	$3,935,680	$3,926,137	$47,607,281

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.

(B) & (C) For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity

Debt Component: Return of 1.9473% reflects a 10% ROE. Per FPSC Order No PSC-10-0153-FOF-EI

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.98% reflects a 10% return on equity

Debt Component: Return of 2.21% based on the 10% ROE. Per FPSC Order PSC 10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.

(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Temporary Heating System (Project No. 41)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$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								
2.	Plant-In-Service/Depreciation Base (A)	$8,970,722	8,970,722	8,970,722	8,970,722	8,970,722	8,970,722	8,970,722	n/a
3.	Less: Accumulated Depreciation	$159,509	167,891	176,273	184,655	193,037	201,419	209,801	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$8,811,212	$8,802,830	$8,794,448	$8,786,067	$8,777,685	$8,769,303	$8,760,921	n/a
6.	Average Net Investment		8,807,021	8,798,639	8,790,258	8,781,876	8,773,494	8,765,112	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		56,180	56,127	56,073	56,020	55,966	55,913	$336,278
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		14,292	14,278	14,265	14,251	14,238	14,224	$85,548
8.	Investment Expenses								
	a. Depreciation (E)		8,382	8,382	8,382	8,382	8,382	8,382	$50,291
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$78,854	$78,787	$78,720	$78,653	$78,586	$78,519	$472,117

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.

(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.

(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Temporary Heating System (Project No. 41)
(in Dollars)

Line	Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1. Investments								
a. Expenditures/Additions		$0	$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								
2. Plant-In-Service/Depreciation Base (A)	$8,970,722	8,970,722	8,970,722	8,970,722	8,970,722	8,970,722	8,970,722	n/a
3. Less: Accumulated Depreciation	$209,801	218,182	226,564	234,946	243,328	251,710	260,092	n/a
4. CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5. Net Investment (Lines 2 - 3 + 4)	$8,760,921	$8,752,539	$8,744,157	$8,735,776	$8,727,394	$8,719,012	$8,710,630	n/a
6. Average Net Investment		8,756,730	8,748,348	8,739,967	8,731,585	8,723,203	8,714,821	n/a
7. Return on Average Net Investment								
a. Equity Component grossed up for taxes (B)		55,859	55,806	55,752	55,699	55,645	55,592	670,631
b. Debt Component (Line 6 x debt rate x 1/12) (C)		14,210	14,197	14,183	14,170	14,156	14,142	170,607
8. Investment Expenses								
a. Depreciation (E)		8,382	8,382	8,382	8,382	8,382	8,382	100,582
b. Amortization (F)								
c. Dismantlement (G)								
d. Property Expenses								
e. Other								
9. Total System Recoverable Expenses (Lines 7 & 8)		$78,451	$78,384	$78,317	$78,250	$78,183	$78,116	$941,820

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: PTN Cooling Canal Monitoring System (Project No. 42)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$3,582,753	3,582,753	3,582,753	3,582,753	3,582,753	3,582,753	3,582,753	n/a
3.	Less: Accumulated Depreciation	$67,592	72,966	78,341	83,715	89,089	94,463	99,837	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$3,515,161	$3,509,786	$3,504,412	$3,499,038	$3,493,664	$3,488,290	$3,482,916	n/a
6.	Average Net Investment		3,512,473	3,507,099	3,501,725	3,496,351	3,490,977	3,485,603	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		22,406	22,372	22,338	22,303	22,269	22,235	$133,922
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		5,700	5,691	5,683	5,674	5,665	5,656	$34,069
8.	Investment Expenses								
	a. Depreciation (E)		5,374	5,374	5,374	5,374	5,374	5,374	$32,245
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$33,480	$33,437	$33,394	$33,351	$33,308	$33,265	$200,236

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: PTN Cooling Canal Monitoring System (Project No. 42)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$3,582,753	3,582,753	3,582,753	3,582,753	3,582,753	3,582,753	3,582,753	n/a
3.	Less: Accumulated Depreciation	$99,837	105,211	110,585	115,960	121,334	126,708	132,082	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$3,482,916	$3,477,542	$3,472,168	$3,466,793	$3,461,419	$3,456,045	$3,450,671	n/a
6.	Average Net Investment		3,480,229	3,474,855	3,469,480	3,464,106	3,458,732	3,453,358	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		22,200	22,166	22,132	22,098	22,063	22,029	266,510
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		5,648	5,639	5,630	5,622	5,613	5,604	67,825
8.	Investment Expenses								
	a. Depreciation (E)		5,374	5,374	5,374	5,374	5,374	5,374	64,490
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$33,222	$33,179	$33,136	$33,093	$33,050	$33,007	$398,925

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Martin Plant Barley Barber Swamp Iron Mitigation Project (Project No. 44)
(in Dollars)

Line	Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1. Investments								
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0
d. Other								
2. Plant-In-Service/Depreciation Base (A)	$147,578	147,578	147,578	147,578	147,578	147,578	147,578	n/a
3. Less: Accumulated Depreciation	$1,679	1,937	2,195	2,453	2,712	2,970	3,228	n/a
4. CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5. Net Investment (Lines 2 - 3 + 4)	$145,899	$145,641	$145,383	$145,125	$144,866	$144,608	$144,350	n/a
6. Average Net Investment		145,770	145,512	145,254	144,996	144,737	144,479	n/a
7. Return on Average Net Investment								
a. Equity Component grossed up for taxes (B)		930	928	927	925	923	922	$5,555
b. Debt Component (Line 6 x debt rate x 1/12) (C)		237	236	236	235	235	234	$1,413
8. Investment Expenses								
a. Depreciation (E)		258	258	258	258	258	258	$1,550
b. Amortization (F)								
c. Dismantlement (G)								
d. Property Expenses								
e. Other								
9. Total System Recoverable Expenses (Lines 7 & 8)		$1,425	$1,423	$1,421	$1,418	$1,416	$1,414	$8,517

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Martin Plant Barley Barber Swamp Iron Mitigation Project (Project No. 44)
(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								
2.	Plant-In-Service/Depreciation Base (A)	$147,578	147,578	147,578	147,578	147,578	147,578	147,578	n/a
3.	Less: Accumulated Depreciation	$3,228	3,487	3,745	4,003	4,261	4,520	4,778	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$144,350	$144,092	$143,833	$143,575	$143,317	$143,059	$142,800	n/a
6.	Average Net Investment		144,221	143,963	143,704	143,446	143,188	142,929	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		920	918	917	915	913	912	11,050
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		234	234	233	233	232	232	2,811
8.	Investment Expenses								
	a. Depreciation (E)		258	258	258	258	258	258	3,099
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,412	$1,410	$1,408	$1,406	$1,404	$1,402	$16,960

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
For Project: 800 MW Unit ESP Project (Project No. 45)
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$43,038,148	$11,473,523	$4,165,124	$1,897,000	$4,669,151	$933,108	$66,176,054
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation	$0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	$0	43,038,148	54,511,671	58,676,795	60,573,795	65,242,946	66,176,054	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$43,038,148	$54,511,671	$58,676,795	$60,573,795	$65,242,946	$66,176,054	n/a
6.	Average Net Investment		21,519,074	48,774,910	56,594,233	59,625,295	62,908,371	65,709,500	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		137,270	311,135	361,015	380,350	401,292	419,161	$2,010,223
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		34,921	79,152	91,841	96,760	102,088	106,633	$511,395
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	$0
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$172,191	$390,287	$452,856	$477,110	$503,380	$525,794	$2,521,618

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.
(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: 800 MW Unit ESP Project (Project No. 45)
(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		$933,108	$2,194,646	$10,228,467	$7,294,413	$3,961,365	$2,907,994	$93,696,047
	b. Clearings to Plant		$62,316,417	$1,437,135	$2,949,218	$0	$0	$0	$66,702,770
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$0	62,316,417	63,753,552	66,702,770	66,702,770	66,702,770	66,702,770	n/a
3.	Less: Accumulated Depreciation	$0	67,509	204,085	345,413	489,936	634,458	778,981	n/a
4.	CWIP - Non Interest Bearing	$66,176,054	4,792,745	5,550,256	12,829,505	20,123,918	24,085,283	26,993,277	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$66,176,054	$67,041,653	$69,099,723	$79,186,862	$86,336,752	$90,153,595	$92,917,066	n/a
6.	Average Net Investment		66,608,853	68,070,688	74,143,292	82,761,807	88,245,174	91,535,330	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		424,898	434,223	472,960	527,937	562,916	583,904	5,017,060
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		108,093	110,465	120,320	134,306	143,204	148,544	1,276,327
8.	Investment Expenses								
	a. Depreciation (E)		67,509	136,576	141,328	144,523	144,523	144,523	778,981
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$600,500	$681,264	$734,607	$806,766	$850,643	$876,970	$7,072,368

Notes:

(A) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 55-59.

(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-4P, pages 55-59.

(F) Applicable amortization period(s). See Form 42-4P, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2012

Return on Capital Investments, Depreciation and Taxes
Deferred Gain on Sales of Emission Allowances
(in Dollars)

Line		Beginning of Period Amount	January Estimated	February Estimated	March Estimated	April Estimated	May Estimated	June Estimated	Six Month Amount	
1	Working Capital Dr (Cr)									
a	158.100 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0		
b	158.200 Allowances Withheld	0	0	0	0	0	0	0		
c	182.300 Other Regulatory Assets-Losses	0	0	0	0	0	0	0		
d	254.900 Other Regulatory Liabilities-Gains	(1,797,695)	(1,747,905)	(1,698,116)	(1,648,326)	(1,598,537)	(1,551,951)	(1,502,116)		
2	Total Working Capital	($1,797,695)	($1,747,905)	($1,698,116)	($1,648,326)	($1,598,537)	($1,551,951)	($1,502,116)		
3	Average Net Working Capital Balance		(1,772,800)	(1,723,010)	(1,673,221)	(1,623,431)	(1,575,244)	(1,527,033)		
4	Return on Average Net Working Capital Balance									
a	Equity Component grossed up for taxes (A)		(11,309)	(10,991)	(10,673)	(10,356)	(10,048)	(9,741)		
b	Debt Component (Line 6 x 1.9473% x 1/12)		(2,877)	(2,796)	(2,715)	(2,635)	(2,556)	(2,478)		
5	Total Return Component		($14,186)	($13,787)	($13,389)	($12,990)	($12,605)	($12,219)	($79,176)	(D)
6	Expense Dr (Cr)									
a	411.800 Gains from Dispositions of Allowances		(49,790)	(49,790)	(49,790)	(49,790)	(51,864)	(50,534)		
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)		($49,790)	($49,790)	($49,790)	($49,790)	($51,864)	($50,534)	($301,556)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		(63,975)	(63,577)	(63,178)	(62,780)	(64,469)	(62,753)		
a	Recoverable Costs Allocated to Energy		(63,975)	(63,577)	(63,178)	(62,780)	(64,469)	(62,753)		
b	Recoverable Costs Allocated to Demand		0	0	0	0	0	0		
9	Energy Jurisdictional Factor		98.02710%	98.02710%	98.02710%	98.02710%	98.02710%	98.02710%		
10	Demand Jurisdictional Factor		98.03105%	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%		
11	Retail Energy-Related Recoverable Costs (B)		(62,713)	(62,322)	(61,932)	(61,541)	(63,197)	(61,515)		
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0		
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($62,713)	($62,322)	($61,932)	($61,541)	($63,197)	($61,515)		

Notes:

(A) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule.
(E) Line 7 is reported on O&M Schedule.

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 2012

Return on Capital Investments, Depreciation and Taxes
Deferred Gain on Sales of Emission Allowances
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1	Working Capital Dr (Cr)								
a	158.100 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0	
b	158.200 Allowances Withheld	$0	0	0	0	0	0	0	
c	182.300 Other Regulatory Assets-Losses	$0	0	0	0	0	0	0	
d	254.900 Other Regulatory Liabilities-Gains	($1,502,116)	(1,451,856)	(1,401,597)	(1,351,337)	(1,301,078)	(1,250,819)	(1,200,559)	
2	Total Working Capital	($1,502,116)	($1,451,856)	($1,401,597)	($1,351,337)	($1,301,078)	($1,250,819)	($1,200,559)	
3	Average Net Working Capital Balance		(1,476,986)	(1,426,727)	(1,376,467)	(1,326,208)	(1,275,948)	(1,225,689)	
4	Return on Average Net Working Capital Balance								
a	Equity Component grossed up for taxes (A)		(9,422)	(9,101)	(8,780)	(8,460)	(8,139)	(7,819)	
b	Debt Component (Line 6 x 1.9473% x 1/12)		(2,397)	(2,315)	(2,234)	(2,152)	(2,071)	(1,989)	
5	Total Return Component		($11,819)	($11,416)	($11,014)	($10,612)	($10,210)	($9,808)	($144,054) (D)
6	Expense Dr (Cr)								
a	411.800 Gains from Dispositions of Allowances		(50,259)	(50,259)	(50,259)	(50,259)	(50,259)	(50,259)	
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)		($50,259)	($50,259)	($50,259)	($50,259)	($50,259)	($50,259)	($603,113) (E)
8	Total System Recoverable Expenses (Lines 5+7)		(62,078)	(61,676)	(61,274)	(60,871)	(60,469)	(60,067)	
a	Recoverable Costs Allocated to Energy		(62,078)	(61,676)	(61,274)	(60,871)	(60,469)	(60,067)	
b	Recoverable Costs Allocated to Demand		0	0	0	0	0	0	
9	Energy Jurisdictional Factor		98.02710%	98.02710%	98.02710%	98.02710%	98.02710%	98.02710%	
10	Demand Jurisdictional Factor		98.03105%	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%	
11	Retail Energy-Related Recoverable Costs (B)		(60,853)	(60,459)	(60,065)	(59,671)	(59,276)	(58,882)	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($60,853)	($60,459)	($60,065)	($59,671)	($59,276)	($58,882)	

Notes:

(A) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule.
(E) Line 7 is reported on O&M Schedule.

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
2012 Annual Capital Depreciation Schedule

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Estimated Balance December 2011	Estimated Balance December 2012
02 - Low NOX Burner Technology						
	02 - Steam Generation Plant	PtEverglades U1	31200	2.30%	2,689,232.57	2,689,232.57
	02 - Steam Generation Plant	PtEverglades U2	31200	2.30%	2,368,972.27	2,368,972.27
	02 - Steam Generation Plant	TurkeyPt U1	31200	2.50%	2,563,376.41	2,563,376.41
	02 - Steam Generation Plant	TurkeyPt U2	31200	2.50%	2,275,221.65	2,275,221.65
02 - Low NOX Burner Technology Total					**9,896,802.90**	**9,896,802.90**
03 - Continuous Emission Monitoring						
	02 - Steam Generation Plant	Cutler Comm	31100	1.70%	64,883.87	64,883.87
	02 - Steam Generation Plant	Cutler Comm	31200	2.20%	36,276.52	36,276.52
	02 - Steam Generation Plant	Cutler U5	31200	2.20%	310,454.41	317,116.41
	02 - Steam Generation Plant	Cutler U6	31200	2.20%	311,861.95	318,523.95
	02 - Steam Generation Plant	Manatee Comm	31200	2.60%	31,859.00	31,859.00
	02 - Steam Generation Plant	Manatee U1	31100	2.10%	56,430.25	56,430.25
	02 - Steam Generation Plant	Manatee U1	31200	2.60%	477,896.88	512,558.88
	02 - Steam Generation Plant	Manatee U2	31100	2.10%	56,332.75	56,332.75
	02 - Steam Generation Plant	Manatee U2	31200	2.60%	508,552.43	515,214.43
	02 - Steam Generation Plant	Martin Comm	31200	2.60%	31,631.74	31,631.74
	02 - Steam Generation Plant	Martin U1	31100	2.10%	36,810.86	36,810.86
	02 - Steam Generation Plant	Martin U1	31200	2.60%	529,318.55	549,980.55
	02 - Steam Generation Plant	Martin U2	31100	2.10%	36,845.37	36,845.37
	02 - Steam Generation Plant	Martin U2	31200	2.60%	525,201.70	545,863.70
	02 - Steam Generation Plant	PtEverglades Comm	31100	1.90%	127,911.34	127,911.34
	02 - Steam Generation Plant	PtEverglades Comm	31200	2.30%	67,787.69	67,787.69
	02 - Steam Generation Plant	PtEverglades U1	31200	2.30%	458,060.74	464,722.74
	02 - Steam Generation Plant	PtEverglades U2	31200	2.30%	480,321.84	486,983.84
	02 - Steam Generation Plant	PtEverglades U3	31200	2.30%	507,658.33	514,320.33
	02 - Steam Generation Plant	PtEverglades U4	31200	2.30%	517,303.41	523,965.41
	02 - Steam Generation Plant	Sanford U3	31100	1.90%	54,282.08	54,282.08
	02 - Steam Generation Plant	Sanford U3	31200	2.40%	434,357.43	434,357.43
	02 - Steam Generation Plant	Scherer U4	31200	2.60%	515,653.32	515,653.32
	02 - Steam Generation Plant	SJRPP - Comm	31100	2.10%	43,193.33	43,193.33
	02 - Steam Generation Plant	SJRPP U1	31200	2.60%	779.50	779.50
	02 - Steam Generation Plant	SJRPP U2	31200	2.60%	779.51	779.51
	02 - Steam Generation Plant	TurkeyPt Comm Fsil	31100	2.10%	59,056.19	59,056.19
	02 - Steam Generation Plant	TurkeyPt Comm Fsil	31200	2.50%	37,954.50	37,954.50
	02 - Steam Generation Plant	TurkeyPt U1	31200	2.50%	545,584.31	552,246.31
	02 - Steam Generation Plant	TurkeyPt U2	31200	2.50%	504,688.53	511,350.53
	05 - Other Generation Plant	FtLauderdale Comm	34100	3.50%	58,859.79	58,859.79
	05 - Other Generation Plant	FtLauderdale Comm	34500	3.40%	34,502.21	34,502.21
	05 - Other Generation Plant	FtLauderdale U4	34300	4.30%	462,254.20	481,254.20
	05 - Other Generation Plant	FtLauderdale U5	34300	4.20%	473,359.99	492,359.99
	05 - Other Generation Plant	FtMyers U2 CC	34300	4.20%	23,619.18	210,591.18
	05 - Other Generation Plant	FtMyers U3 CC	34300	5.20%	2,282.97	2,282.97
	05 - Other Generation Plant	Martin U3	34300	4.20%	416,872.29	458,196.29
	05 - Other Generation Plant	Martin U4	34300	4.20%	409,474.06	450,798.06
	05 - Other Generation Plant	Martin U8	34300	4.30%	13,693.21	13,693.21
	05 - Other Generation Plant	PtEverglades GTs	34300	3.40%	0.00	13,324.00
	05 - Other Generation Plant	Putnam Comm	34100	2.60%	82,857.82	82,857.82
	05 - Other Generation Plant	Putnam Comm	34300	4.20%	3,138.97	3,138.97
	05 - Other Generation Plant	Putnam U1	34300	4.00%	346,616.08	359,940.08
	05 - Other Generation Plant	Putnam U2	34300	3.30%	380,355.07	393,679.07
	05 - Other Generation Plant	Sanford U4	34300	4.80%	98,339.95	218,987.95
	05 - Other Generation Plant	Sanford U5	34300	4.20%	56,521.05	177,169.05
03 - Continuous Emission Monitoring Total					**10,232,475.17**	**10,957,307.17**
04 - Clean Closure Equivalency Demonstration						
	02 - Steam Generation Plant	PtEverglades Comm	31100	1.90%	19,812.30	19,812.30
	02 - Steam Generation Plant	TurkeyPt Comm Fsil	31100	2.10%	21,799.28	21,799.28
04 - Clean Closure Equivalency Demonstration Total					**41,611.58**	**41,611.58**

Florida Power & Light Company
Environmental Cost Recovery Clause
2012 Annual Capital Depreciation Schedule

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Estimated Balance December 2011	Estimated Balance December 2012
05 - Maintenance of Above Ground Fuel Tanks						
	02 - Steam Generation Plant	Manatee Comm	31100	2.10%	3,111,263.35	3,111,263.35
	02 - Steam Generation Plant	Manatee Comm	31200	2.60%	174,543.23	174,543.23
	02 - Steam Generation Plant	Manatee U1	31100	2.10%	5,500.00	5,500.00
	02 - Steam Generation Plant	Manatee U1	31200	2.60%	104,845.35	104,845.35
	02 - Steam Generation Plant	Manatee U2	31100	2.10%	5,500.00	5,500.00
	02 - Steam Generation Plant	Manatee U2	31200	2.60%	127,429.19	127,429.19
	02 - Steam Generation Plant	Martin Comm	31100	2.10%	1,110,450.32	1,110,450.32
	02 - Steam Generation Plant	Martin Comm	31200	2.60%	94,329.22	94,329.22
	02 - Steam Generation Plant	Martin U1	31100	2.10%	176,338.83	176,338.83
	02 - Steam Generation Plant	PtEverglades Comm	31100	1.90%	1,132,078.22	1,132,078.22
	02 - Steam Generation Plant	Sanford U3	31100	1.90%	796,754.11	796,754.11
	02 - Steam Generation Plant	SJRPP - Comm	31100	2.10%	42,091.24	42,091.24
	02 - Steam Generation Plant	SJRPP - Comm	31200	2.60%	2,292.39	2,292.39
	02 - Steam Generation Plant	TurkeyPt Comm Fsil	31100	2.10%	87,560.23	87,560.23
	02 - Steam Generation Plant	TurkeyPt U2	31100	2.10%	42,158.96	42,158.96
	05 - Other Generation Plant	FtLauderdale Comm	34200	3.80%	898,110.65	898,110.65
	05 - Other Generation Plant	FtLauderdale GTs	34200	2.60%	584,290.23	1,034,290.23
	05 - Other Generation Plant	FtMyers GTs	34200	2.70%	133,478.89	133,478.89
	05 - Other Generation Plant	PtEverglades GTs	34200	2.60%	2,359,099.94	2,359,099.94
	05 - Other Generation Plant	Putnam Comm	34200	2.90%	749,025.94	749,025.94
05 - Maintenance of Above Ground Fuel Tanks Total					**11,737,140.29**	**12,187,140.29**
07 - Relocate Turbine Lube Oil Piping						
	03 - Nuclear Generation Plant	StLucie U1	32300	2.40%	31,030.00	31,030.00
07 - Relocate Turbine Lube Oil Piping Total					**31,030.00**	**31,030.00**
08 - Oil Spill Clean-up/Response Equipment						
	02 - Steam Generation Plant	Amortizable	31650	5-Year	103,360.48	150,360.48
	02 - Steam Generation Plant	Amortizable	31670	7-Year	393,302.05	303,084.85
	02 - Steam Generation Plant	Manatee Comm	31100	2.10%	3,000.00	3,000.00
	02 - Steam Generation Plant	Martin Comm	31600	2.40%	23,107.32	23,107.32
	02 - Steam Generation Plant	PtEverglades Comm	31100	1.90%	365,962.73	365,962.73
	05 - Other Generation Plant	Amortizable	34650	5-Year	22,458.48	22,458.48
	05 - Other Generation Plant	Amortizable	34670	7-Year	31,180.89	5,734.43
	08 - General Plant		39000	2.10%	4,412.76	4,412.76
08 - Oil Spill Clean-up/Response Equipment Total					**946,784.71**	**878,121.05**
10 - Reroute Storm Water Runoff						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.80%	117,793.83	117,793.83
10 - Reroute Storm Water Runoff Total					**117,793.83**	**117,793.83**
12 - Scherer Discharge Pipline						
	02 - Steam Generation Plant	Scherer Comm	31000	0.00%	9,936.72	9,936.72
	02 - Steam Generation Plant	Scherer Comm	31100	2.10%	524,872.97	524,872.97
	02 - Steam Generation Plant	Scherer Comm	31200	2.60%	328,761.62	328,761.62
	02 - Steam Generation Plant	Scherer Comm	31400	2.60%	689.11	689.11
12 - Scherer Discharge Pipline Total					**864,260.42**	**864,260.42**
20 - Wastewater/Stormwater Discharge Elimination						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	0.00%	0.00	0.00
	02 - Steam Generation Plant	Martin U1	31200	2.60%	380,994.77	380,994.77
	02 - Steam Generation Plant	Martin U2	31200	2.60%	416,671.92	416,671.92
	02 - Steam Generation Plant	PtEverglades Comm	31100	1.90%	436,440.86	436,440.86
20 - Wastewater/Stormwater Discharge Elimination Total					**1,234,107.55**	**1,234,107.55**
21 - St. Lucie Turtle Nets						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.80%	352,942.34	2,762,689.34
21 - St. Lucie Turtle Nets Total					**352,942.34**	**2,762,689.34**
22 - Pipeline Integrity						
	02 - Steam Generation Plant	Manatee Comm	31100	2.10%	0.00	750,000.00
	02 - Steam Generation Plant	Martin Comm	31100	2.10%	1,229,528.00	1,229,528.00
22 - Pipeline Integrity Total					**1,229,528.00**	**1,979,528.00**

Florida Power & Light Company
Environmental Cost Recovery Clause
2012 Annual Capital Depreciation Schedule

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Estimated Balance December 2011	Estimated Balance December 2012
23 - Spill Prevention Clean-Up & Countermeasures						
	02 - Steam Generation Plant	Cutler Comm	31400	2.20%	12,236.00	12,236.00
	02 - Steam Generation Plant	Cutler U5	31400	2.20%	18,388.00	18,388.00
	02 - Steam Generation Plant	Manatee Comm	31100	2.10%	807,718.60	807,718.60
	02 - Steam Generation Plant	Manatee Comm	31200	2.60%	33,272.38	33,272.38
	02 - Steam Generation Plant	Manatee Comm	31500	2.40%	26,325.43	26,325.43
	02 - Steam Generation Plant	Manatee U1	31200	2.60%	45,749.52	45,749.52
	02 - Steam Generation Plant	Manatee U2	31200	2.60%	37,431.45	37,431.45
	02 - Steam Generation Plant	Martin Comm	31100	2.10%	343,785.10	343,785.10
	02 - Steam Generation Plant	Martin Comm	31500	2.40%	34,754.74	34,754.74
	02 - Steam Generation Plant	PtEverglades Comm	31100	1.90%	2,967,754.07	2,967,754.07
	02 - Steam Generation Plant	PtEverglades Comm	31200	2.30%	159,754.32	159,754.32
	02 - Steam Generation Plant	PtEverglades Comm	31500	2.00%	7,782.85	7,782.85
	02 - Steam Generation Plant	Sanford Comm	31100	1.90%	0.00	200,000.00
	02 - Steam Generation Plant	Sanford U3	31100	1.90%	850,530.75	850,530.75
	02 - Steam Generation Plant	Sanford U3	31200	2.40%	211,727.22	211,727.22
	02 - Steam Generation Plant	TurkeyPt Comm Fsil	31100	2.10%	92,013.09	92,013.09
	02 - Steam Generation Plant	TurkeyPt Comm Fsil	31500	2.20%	13,559.00	13,559.00
	03 - Nuclear Generation Plant	StLucie Comm	32400	1.80%	5,000.00	5,000.00
	03 - Nuclear Generation Plant	StLucie U1	32300	2.40%	1,019,614.24	1,019,614.24
	03 - Nuclear Generation Plant	StLucie U1	32400	1.80%	437,945.38	437,945.38
	03 - Nuclear Generation Plant	StLucie U2	32300	2.40%	552,389.64	552,389.64
	05 - Other Generation Plant	Amortizable	34670	7-Year	7,065.10	0.00
	05 - Other Generation Plant	FtLauderdale Comm	34100	3.50%	189,219.17	189,219.17
	05 - Other Generation Plant	FtLauderdale Comm	34200	3.80%	1,480,169.46	1,480,169.46
	05 - Other Generation Plant	FtLauderdale Comm	34300	6.00%	28,250.00	28,250.00
	05 - Other Generation Plant	FtLauderdale GTs	34100	2.20%	92,726.74	92,726.74
	05 - Other Generation Plant	FtLauderdale GTs	34200	2.60%	513,250.07	513,250.07
	05 - Other Generation Plant	FtMyers GTs	34100	2.30%	98,714.92	178,714.92
	05 - Other Generation Plant	FtMyers GTs	34200	2.70%	629,983.29	629,983.29
	05 - Other Generation Plant	FtMyers GTs	34500	2.20%	12,430.00	12,430.00
	05 - Other Generation Plant	FtMyers U2 CC	34300	4.20%	49,727.00	49,727.00
	05 - Other Generation Plant	FtMyers U3 CC	34500	3.40%	12,430.00	12,430.00
	05 - Other Generation Plant	Martin Comm	34100	3.50%	61,215.95	61,215.95
	05 - Other Generation Plant	Martin U8	34200	3.80%	84,868.00	84,868.00
	05 - Other Generation Plant	PtEverglades GTs	34100	2.20%	454,080.68	454,080.68
	05 - Other Generation Plant	PtEverglades GTs	34200	2.60%	1,835,189.50	1,835,189.50
	05 - Other Generation Plant	PtEverglades GTs	34500	2.10%	7,782.85	7,782.85
	05 - Other Generation Plant	Putnam Comm	34100	2.60%	148,511.20	148,511.20
	05 - Other Generation Plant	Putnam Comm	34200	2.90%	1,733,971.58	1,733,971.58
	05 - Other Generation Plant	Putnam Comm	34500	2.50%	60,746.93	60,746.93
	06 - Transmission Plant - Electric		35200	1.90%	1,050,156.83	1,080,156.83
	06 - Transmission Plant - Electric		35300	2.60%	177,981.88	177,981.88
	06 - Transmission Plant - Electric		35800	1.80%	64,088.54	64,088.54
	07 - Distribution Plant - Electric		36100	1.90%	2,963,887.67	3,083,887.67
	07 - Distribution Plant - Electric		36670	2.00%	81,787.45	86,302.45
	08 - General Plant		39000	2.10%	146,691.32	146,691.32
23 - Spill Prevention Clean-Up & Countermeasures Total					**19,662,657.91**	**20,090,107.81**
24 - Manatee Reburn						
	02 - Steam Generation Plant	Manatee U1	31200	2.60%	16,687,067.37	16,687,067.37
	02 - Steam Generation Plant	Manatee U2	31200	2.60%	15,062,479.29	15,062,479.29
24 - Manatee Reburn Total					**31,749,546.66**	**31,749,546.66**
25 - PPE ESP Technology						
	02 - Steam Generation Plant	PtEverglades U1	31100	1.90%	298,709.93	298,709.93
	02 - Steam Generation Plant	PtEverglades U1	31200	2.30%	10,404,603.15	10,404,603.15
	02 - Steam Generation Plant	PtEverglades U1	31500	2.00%	2,500,248.85	2,500,248.85
	02 - Steam Generation Plant	PtEverglades U1	31600	2.10%	307,032.30	307,032.30
	02 - Steam Generation Plant	PtEverglades U2	31100	1.90%	184,084.01	184,084.01
	02 - Steam Generation Plant	PtEverglades U2	31200	2.30%	11,979,735.29	11,979,735.29
	02 - Steam Generation Plant	PtEverglades U2	31500	2.00%	3,954,581.63	3,954,581.63
	02 - Steam Generation Plant	PtEverglades U2	31600	2.10%	324,086.94	324,086.94
	02 - Steam Generation Plant	PtEverglades U3	31100	1.90%	713,693.44	713,693.44
	02 - Steam Generation Plant	PtEverglades U3	31200	2.30%	18,160,533.65	18,160,533.65
	02 - Steam Generation Plant	PtEverglades U3	31500	2.00%	4,304,056.69	4,304,056.69
	02 - Steam Generation Plant	PtEverglades U3	31600	2.10%	528,541.18	528,541.18
	02 - Steam Generation Plant	PtEverglades U4	31100	1.90%	313,275.79	313,275.79
	02 - Steam Generation Plant	PtEverglades U4	31200	2.30%	20,646,501.29	20,646,501.29
	02 - Steam Generation Plant	PtEverglades U4	31500	2.00%	6,729,950.05	6,729,950.05
	02 - Steam Generation Plant	PtEverglades U4	31600	2.10%	551,535.30	551,535.30
25 - PPE ESP Technology Total					**81,901,169.49**	**81,901,169.49**

Florida Power & Light Company
Environmental Cost Recovery Clause
2012 Annual Capital Depreciation Schedule

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Estimated Balance December 2011	Estimated Balance December 2012
26 - UST Remove/Replace						
	08 - General Plant		39000	2.10%	115,446.69	115,446.69
26 - UST Remove/Replace Total					**115,446.69**	**115,446.69**
31 - Clean Air Interstate Rule (CAIR)						
	02 - Steam Generation Plant	Manatee Comm	31100	2.10%	102,052.47	102,052.47
	02 - Steam Generation Plant	Manatee Comm	31200	2.60%	518,274.99	518,274.99
	02 - Steam Generation Plant	Manatee U1	31200	2.60%	20,059,060.47	20,059,060.47
	02 - Steam Generation Plant	Manatee U1	31400	2.60%	7,270,679.87	7,270,679.87
	02 - Steam Generation Plant	Manatee U2	31200	2.60%	20,493,592.71	20,493,592.71
	02 - Steam Generation Plant	Manatee U2	31400	2.60%	8,121,992.61	8,121,992.61
	02 - Steam Generation Plant	Martin Comm	31400	2.60%	287,257.77	287,257.77
	02 - Steam Generation Plant	Martin U1	31200	2.60%	20,695,251.33	20,695,251.33
	02 - Steam Generation Plant	Martin U1	31400	2.60%	7,788,541.34	7,788,541.34
	02 - Steam Generation Plant	Martin U2	31200	2.60%	19,057,799.99	19,057,799.99
	02 - Steam Generation Plant	Martin U2	31400	2.60%	7,487,256.36	7,487,256.36
	02 - Steam Generation Plant	Scherer U4	31200	2.60%	0.00	360,003,781.76
	02 - Steam Generation Plant	SJRPP U1	31200	2.60%	27,708,298.93	27,708,298.93
	02 - Steam Generation Plant	SJRPP U1	31500	2.40%	455,145.91	455,145.91
	02 - Steam Generation Plant	SJRPP U1	31600	2.40%	9,137.83	9,137.83
	02 - Steam Generation Plant	SJRPP U2	31200	2.60%	26,630,303.07	26,630,303.07
	02 - Steam Generation Plant	SJRPP U2	31500	2.40%	426,219.91	426,219.91
	02 - Steam Generation Plant	SJRPP U2	31600	2.40%	9,591.24	9,591.24
	05 - Other Generation Plant	FtLauderdale GTs	34300	2.90%	110,241.57	110,241.57
	05 - Other Generation Plant	FtMyers GTs	34300	3.10%	57,855.19	57,855.19
	05 - Other Generation Plant	Martin Comm	34100	3.50%	763,350.13	763,350.13
	05 - Other Generation Plant	Martin Comm	34300	4.30%	244,343.38	244,343.38
	05 - Other Generation Plant	Martin Comm	34500	3.40%	292,498.67	292,498.67
	05 - Other Generation Plant	PtEverglades GTs	34300	3.40%	107,874.44	107,874.44
	07 - Distribution Plant - Electric		36500	3.90%	411,775.23	411,775.23
31 - Clean Air Interstate Rule (CAIR) Total					**169,108,395.41**	**529,112,177.17**
33 - Clean Air Mercury Rule (CAMR)						
	02 - Steam Generation Plant	Scherer U4	31200	2.60%	107,265,403.72	107,397,798.72
33 - Clean Air Mercury Rule (CAMR) Total					**107,265,403.72**	**107,397,798.72**
35 - Martin Drinking Water System						
	02 - Steam Generation Plant	Martin Comm	31100	2.10%	235,391.32	235,391.32
35 - Martin Drinking Water System Total					**235,391.32**	**235,391.32**
36 - Low Level Waste Storage						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.80%	6,926,841.52	6,926,841.52
	03 - Nuclear Generation Plant	TurkeyPt Comm	32100	1.80%	0.00	6,577,368.00
36 - Low Level Waste Storage Total					**6,926,841.52**	**13,504,209.52**
37 - DeSoto Solar Energy Center						
	05 - Other Generation Plant	Amortizable	34630	3-Year	12,102.91	2,000.00
	05 - Other Generation Plant	Amortizable	34650	5-Year	21,934.62	21,934.62
	05 - Other Generation Plant	Amortizable	34670	7-Year	79,264.09	79,264.09
	05 - Other Generation Plant	DeSoto Solar	34000	0.00%	255,507.00	255,507.00
	05 - Other Generation Plant	DeSoto Solar	34100	3.30%	4,449,376.76	4,449,376.76
	05 - Other Generation Plant	DeSoto Solar	34300	3.30%	116,103,531.68	116,103,531.68
	05 - Other Generation Plant	DeSoto Solar	34500	3.30%	26,137,080.76	26,137,080.76
	6 - Other Generation Plant	DeSoto Solar	34600	3.30%	0.00	74,000.00
	06 - Transmission Plant - Electric		35200	1.90%	2,603.27	2,603.27
	06 - Transmission Plant - Electric		35300	2.60%	797,283.55	797,283.55
	06 - Transmission Plant - Electric		35310	2.90%	1,712,305.00	1,712,305.00
	06 - Transmission Plant - Electric		35500	3.40%	394,417.57	394,417.57
	06 - Transmission Plant - Electric		35600	3.20%	191,357.87	191,357.87
	07 - Distribution Plant - Electric		36100	1.90%	608,237.66	608,237.66
	07 - Distribution Plant - Electric		36200	2.60%	2,214,848.49	2,214,848.49
	08 - General Plant		39220	9.40%	28,426.16	28,426.16
	08 - General Plant	Amortizable	39720	7-Year	22,113.81	22,113.81
37 - DeSoto Solar Energy Center Total					**153,030,391.20**	**153,094,288.29**

Florida Power & Light Company
Environmental Cost Recovery Clause
2012 Annual Capital Depreciation Schedule

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Estimated Balance December 2011	Estimated Balance December 2012
38 - Spacecoast Solar Energy Center						
	01 - Intangible Plant	Amortizable	30300	30-Year	6,359,027.00	6,359,027.00
	05 - Other Generation Plant	Amortizable	34630	3-Year	7,271.71	9,271.71
	05 - Other Generation Plant	Amortizable	34650	5-Year	9,438.49	9,438.49
	05 - Other Generation Plant	Amortizable	34670	7-Year	40,744.77	40,744.77
	05 - Other Generation Plant	Spacecoast Solar	34100	3.30%	1,208,992.67	1,208,992.67
	05 - Other Generation Plant	Spacecoast Solar	34300	3.30%	60,362,804.15	60,362,804.15
	05 - Other Generation Plant	Spacecoast Solar	34600	3.30%	7,210.00	25,210.00
	06 - Transmission Plant - Electric		35300	2.60%	139,390.84	139,390.84
	07 - Distribution Plant - Electric		36100	1.90%	269,805.86	269,805.86
	07 - Distribution Plant - Electric		36200	2.60%	2,187,146.99	2,187,146.99
	08 - General Plant		39220	9.40%	31,858.14	31,858.14
	08 - General Plant	Amortizable	39720	7-Year	6,350.40	6,350.40
38 - Spacecoast Solar Energy Center Total					**70,630,041.02**	**70,650,041.02**
39 - Martin Solar Energy Center						
	05 - Other Generation Plant	Amortizable	34650	5-Year	21,384.00	21,384.00
	05 - Other Generation Plant	Amortizable	34670	7-Year	0.00	200,000.00
	05 - Other Generation Plant	Martin Solar	34000	0.00%	216,844.31	216,844.31
	05 - Other Generation Plant	Martin Solar	34100	3.30%	90.55	815,090.55
	05 - Other Generation Plant	Martin Solar	34300	3.30%	398,522,547.42	400,572,547.42
	05 - Other Generation Plant	Martin Solar	34600	3.30%	1,299.31	1,299.31
	05 - Other Generation Plant	Martin U8	34300	4.30%	379,929.68	379,929.68
	06 - Transmission Plant - Electric		35500	3.40%	618,700.98	618,700.98
	06 - Transmission Plant - Electric		35600	3.20%	368,305.53	368,305.53
	07 - Distribution Plant - Electric		36400	4.10%	9,282.42	9,282.42
	07 - Distribution Plant - Electric		36660	1.50%	94,476.14	94,476.14
	07 - Distribution Plant - Electric		36760	2.60%	2,728.36	2,728.36
	08 - General Plant		39220	9.40%	25,193.18	25,193.18
	08 - General Plant		39240	11.10%	205,307.14	205,307.14
	08 - General Plant		39290	3.50%	97,633.07	97,633.07
	08 - General Plant	Amortizable	39420	7-Year	18,992.89	18,992.89
	08 - General Plant	Amortizable	39720	7-Year	3,203.99	3,203.99
39 - Martin Solar Energy Center Total					**400,585,918.97**	**403,650,918.97**
41 - Manatee Heaters						
	02 - Steam Generation Plant	CapeCanaveral Comm	31400	0.70%	4,627,040.58	4,627,040.58
	02 - Steam Generation Plant	Riviera Comm	31400	0.60%	2,605,268.34	2,605,268.34
	06 - Transmission Plant - Electric		35300	2.60%	283,596.40	283,596.40
	07 - Distribution Plant - Electric		36100	1.90%	29,779.49	29,779.49
	07 - Distribution Plant - Electric		36200	2.60%	484,745.22	484,745.22
	07 - Distribution Plant - Electric		36400	4.10%	223,459.91	223,459.91
	07 - Distribution Plant - Electric		36500	3.90%	302,616.24	302,616.24
	07 - Distribution Plant - Electric		36660	1.50%	221,325.50	221,325.50
	07 - Distribution Plant - Electric		36760	2.60%	168,995.42	168,995.42
	07 - Distribution Plant - Electric		36910	3.90%	607.06	607.06
	08 - General Plant	Amortizable	39720	7-Year	23,287.46	23,287.46
41 - Manatee Heaters Total					**8,970,721.62**	**8,970,721.62**
42 - Turkey Point Cooling Canal Monitoring						
	03 - Nuclear Generation Plant	TurkeyPt Comm	32100	1.80%	3,582,752.89	3,582,752.89
42 - Turkey Point Cooling Canal Monitoring Total					**3,582,752.89**	**3,582,752.89**
44 - Martin Plant Barley Barber Swamp Iron Mitigation Project						
	02 - Steam Generation Plant	Martin Comm	31100	2.10%	147,578.17	147,578.17
44 - Martin Plant Barley Barber Swamp Iron Mitigation Project Total					**147,578.17**	**147,578.17**
45 - 800MW Unit ESP Project						
	02 - Steam Generation Plant	Manatee U2	31200	2.60%	0.00	66,702,770.00
45 - 800MW Unit ESP Project Total					**0.00**	**66,702,770.00**
Grand Total					**1,090,596,733.38**	**1,531,855,310.47**

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Air Operating Permit Fees - O & M**
Project No. 1

Project Description:
The Clean Air Act Amendments of 1990, Public Law 101-549, and Florida Statutes 403.0872, require each major source of air pollution to pay an annual license fee. The amount of the fee is based on each source's previous year's emissions. It is calculated by multiplying the applicable annual operation license fee factor by the tons of each air pollutant emitted by the unit during the previous year and regulated in each unit's air operating permit, up to a total of 4,000 tons per pollutant. The major regulated pollutants at the present time are sulfur dioxide (SO_2), nitrogen oxides (NO_x) and particulate matter. The fee covers units in FPL's service area, as well as Unit 4 of Plant Scherer located in Juliette, Georgia, within the Georgia Power Company service area. FPL's share of ownership of that unit is 76.36%. The fees for FPL's units are paid to the Florida Department of Environmental Protection (FDEP) generally in February of each year, whereas FPL pays its share of the fees for Scherer Unit 4 to Georgia Power Company on a monthly basis.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
The monthly fees for 2010 emissions have been paid and continue to be paid in 2011. Year 2010 air operating permit fees for the Florida facilities were calculated in January 2011 utilizing 2010 operating information. They were paid to the FDEP in February, 2011.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project expenditures are estimated to be $98,465 or 7.7% lower than previously projected. Lower than projected gas prices resulted in less run time than estimated for Port Everglades (PPE) Units 3 and 4, which only burn oil. Air Permit fees and payments to the State of Florida are based on actual unit operation and performance.

Project Progress Summary:
The monthly fees for 2010 emissions have been paid and continue to be paid in 2011. Year 2010 air operating permit fees for the Florida facilities were calculated in January 2011 utilizing 2010 operating information. They were paid to the FDEP in February, 2011.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are $1,290,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Continuous Emission Monitoring Systems (CEMS) - O & M
Project No. 3a

Project Description:
The Clean Air Act Amendments of 1990, Public Law 101-549, established requirements for the monitoring, record keeping, and reporting of SO2, NOx, CO, Carbon Dioxide (CO2/O2) emissions, as well as opacity data from affected air pollution sources. FPL has 57 units, which are affected and which have installed CEMS to comply with these requirements.

40 CFR Part 75 includes the general requirements for the installation, certification, operation and maintenance of CEMS and specific requirements for the monitoring of pollutants and opacity. These Systems continuously extract and analyze gaseous samples for each power plant stack and have automated data acquisition and reporting capability. Operation and maintenance of these systems in accordance with the provisions of 40 CFR Part 75 is an ongoing activity, which follow the Title IV CEMS Quality Assurance Program Manual.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
Operation and maintenance of the CEMS continue to be performed according to requirements of the Title IV CEM Quality Assurance Program Manual, 40 CFR Parts 60 & 75 regulations and all applicable FAC, as well as local requirements. Relative Accuracy Tests and Linearity Tests continue to be performed as scheduled for quality assurance and as needed for diagnostic or recertification requirements. QA/QC maintenance continues to be performed on the analyzers to meet reliability and availability requirements. CEMS required parts continue to be purchased as needed for repairs and/or preventative maintenance. Equipment having met end of life has been replaced as recommended by OEMs. Calibration span gases continue to be purchased as needed to meet required daily and QA calibrations. Analysis of fuel oil for sulfur content, heat of combustion and carbon continues to be performed per the requirements of 40 CFR Part 75, Appendix D. CEMS 24/7 Software Support contract with Babcock & Wilcox / KVB-Enertec (CEMS NETDAHS) continues to be maintained to ensure proper functionality as well as the integrity of the CEMS data. Maintenance of the software also ensures compliance with current rules or regulations or changes made by the EPA, State and Local Agencies. Training on the Operation and Maintenance of the system, as well as rule/regulation changes continue as needed.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project expenditures are estimated to be $143,359 or 19.8% higher than previously projected. The variance is primarily due to the following reasons:

- The micro motion fuel oil monitors at Plant Manatee Units 1 and 2 were replaced due to normal wear and tear.
- The umbilical cords at Plant Martin Units 1 and 2 failed and were replaced.
- Estimates for preventive maintenance at the Plant Port Everglades were inadvertently omitted from the 2011 Projection filing.
- Additional transformers were installed in each CEMS shelter to enable complete redundancy and provide a dependable backup power supply to avoid loss of data during a power outage.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
This is an ongoing project. Each reporting period will include the cost of quality assurance activities, training, spare parts, calibration gas, and software support.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are $754,456.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Maintenance of Stationary Above Ground Fuel Storage Tanks - O&M**
Project No. 5a

Project Description:
Florida Administrative Code (F.A.C.) Chapter 62-761, previously 17-762, which became effective on March 12, 1991, provides standards for the maintenance of stationary above ground fuel storage tank systems. These standards impose various implementation schedules for inspections/repairs and upgrades to fuel storage tanks.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
Work continued on miscellaneous maintenance of above ground fuel storage tanks and piping systems. All required API 653 external inspections will be completed for this year and all 2011 tank registration fees have been paid. As of 8/1/11, all corporate tanks, which were due for internal & external API inspections in this reporting period, were inspected with no deficiencies identified. Total of two (2) internal and sixteen (16) external API inspections were conducted in the reporting period. Tanks TMT-1271A, TMT-1271B, TMR-1272. TMT-1272 and PPE-4M TPE were water blasted and painted. Tank PPE-904's Delta Liner was found to have failed and efforts are currently underway to remove the remaining product from the tank and complete repairs to this tank in 2012.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project expenditures were $40,018 or 2.3% lower than previously projected.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
This is an ongoing project. Each reporting period will include ongoing maintenance of above ground fuel storage tanks in accordance with F.A.C. Chapter 62-761. TPE Tanks 901 & 902 dike liners were repaired as needed.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are $2,192,743.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Oil Spill Cleanup/Response Equipment - O&M**
Project No. 8a

Project Description:
The Oil Pollution Act of 1990 (OPA '90) mandates that all liable parties in the petroleum handling industry file plans by August 18, 1993. In these plans, a liable party must identify (among other items) its spill management team, organization, resources and training. Within this project, FPL developed the plans for ten power plants, five fuel oil terminals, three pipelines, and one corporate plan. Additionally, FPL purchased the mandated response resources and provided for mobilization to a worst case discharge at each site.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
Plan updates have continued to be performed and filed for all sites as required. Routine maintenance of all oil spill equipment has continued throughout the year as well as the performance of spill management drills, including deployment drills throughout the system. A corporate team deployment drill will also be conducted. There has also been training for some new team members. Repairs will be made to the OSR Equipment Storage Warehouse located at the Martin Fuel Terminal.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project expenditures are estimated to be $20,877 or 10.6% higher than previously projected. The variance is primarily due to repairs of the boat ramp at Plant Sanford, which were not included in the original estimate. As a result of wear and tear caused by water-level fluctuations in the river, repairs to the boat ramp were required in order to make the ramp usable for launching the oil spill response boat and equipment.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
This is an ongoing project. Each reporting period will include ongoing maintenance of all oil spill equipment in accordance with OPA 90. Additionally, following a formal assessment of the oil spill program, FPL retained a contractor to perform the mandated OSRO (oil spill removal organization) function. This contractor also performs maintenance (required) on the oil spill equipment at all of the power plants as well as performs an annual (required) equipment deployment drill at these facilities.

FPL has retained a spill management company to assist in corporate-level responses, improved/enhanced the Fleet's ability to mobilize spill equipment (specifically boats), and continue to certify all oil spill response members in the NIMS mandated Incident Command System (ICS).

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are $212,600.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: RCRA Corrective Action - O & M
Project No. 13

Project Description:
Under the Hazardous and Solid Waste Amendments of 1984 (amending the Resource Conservation and Recovery Act, or RCRA), the U.S. EPA has the authority to require hazardous waste treatment facilities to investigate whether there have been releases of hazardous waste or constituents from non-regulated units on the facility site. If contamination is found to be present at levels that represent a threat to human health or the environment, the facility operator can be required to undertake "corrective action" to remediate the contamination. In April 1994, the U.S. EPA advised FPL that it intended to initiate RCRA Facility Assessments (RFAs) at FPL's nine former hazardous waste treatment facility sites. The RFA is the first step in the RCRA Corrective Action process. At a minimum, FPL will be responding to the agency's requests for information concerning the operation of these power plants, their waste streams, their former hazardous waste treatment facilities, and their non-regulated Solid Waste Management Units (SWMUs). FPL may also conduct assessments of human health risks resulting from possible releases from the SWMU's in order to demonstrate that any residual contamination does not represent an undue threat to human health or the environment. Other response actions could include a voluntary clean-up or compliance with the agency's imposition of the full gamut of RCRA Corrective Action requirements, including RCRA Facility Investigation, Corrective Measures Study, and Corrective Measures Implementation.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
On June 29, 2010, FDEP and FPL signed an Amended Agreement (05-0242) and Amended Consent Order (93-2924) acknowledging that the Turkey Point Nuclear would be clean closed with no further actions under the RCRA program. The March 5, 1999 Consent Order for St Lucie Nuclear Plant is amended by the new agreement, with the objective to achieve a no further action either with or without controls. Seven contaminated areas at St Lucie Nuclear are included in the amended agreement and amended consent order that will require continued monitoring, reporting and ultimate site rehabilitation. FPL and the FDEP have the option to defer further assessment and/or remediation until the nuclear plant is decommissioned as directed under the authority of the Nuclear Regulatory Commission.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project expenditures were $92,127, versus an original estimate of $0. The variance is primarily due to FPL receiving a letter on April 15, 2011 from the Florida Department of Environmental Protection (FDEP) requiring additional actions. The added costs of actions required by the April 15, 2011 letter and of evaluating, developing and implementing control documents in connection with the status change are reasons for the variance.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
On June 29, 2010, FDEP and FPL signed an Amended Agreement (05-0242) and Amended Consent Order (93-2924) acknowledging that the Turkey Point Nuclear would be clean closed with no further actions under the RCRA program. The new agreement and consent order included requirements for FPL to manage site rehabilitation of several contaminated areas at the St. Lucie Nuclear Plant, and provided options for closure of these areas under the RCRA program. In support of the amended agreement and amended consent order and in response to FPL's report to FDEP's expected impact, FDEP issued a letter to FPL on April 15, 2011, requiring numerous actions. In order to meet the conditions of these agreements, FPL recommended that FDEP consider a status change for the contaminated areas from "active remediation" to "no further action with controls" as allowed by the RCRA Contaminated Sites Program.

Project Projection:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are $100,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **NPDES Permit Fees – O&M**
Project No. 14

Project Description:
In compliance with State of Florida Rule 62-4.052, FPL is required to pay annual regulatory program and surveillance fees for any permits it requires to discharge wastewater to surface waters under the National Pollution Discharge Elimination System. These fees effect the Florida legislature's intent that the Florida Department of Environmental Protection's (FDEP) costs for administering the NPDES program be borne by the regulated parties, as applicable. The fees for each permit type are as set forth in the rule, with an effective date of May 1, 1995, for their implementation.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
The NPDES permit fees were paid to FDEP for power generation operating plants and nuclear plants.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
No variance projected.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
The NPDES annual regulatory program and surveillance fees were paid to FDEP for power generation operating plants and nuclear plants.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are $115,200.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Disposal of Noncontainerized Liquid Waste - O&M**
Project 17a

Project Description:
FPL manages ash from heavy oil fired power plants using a wet ash system. Ash from the dust collector and economizer is sluiced to surface ash basins. The ash sludge is then pH adjusted to precipitate metals. In order to comply with Florida Administrative Code 62-701.300 (10), the ash is then de-watered using a plate/frame filter-press in order to dispose of it in a Class I landfill or ship by railcar to a processing facility for beneficial reuse.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
All work will be completed in August of 2011 at the Martin Plant, including the ash basin cleanout for 2011. Repairs to the ash press include repairs to an air compressor.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project expenditures are estimated to be $161,000, or 71.2% lower than previously projected. The variance is primarily due to the deferral of ash processing at the Port Everglades, Turkey Point and Manatee plants because the plants are being run less on oil than originally anticipated due to the lower cost of natural gas.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
This is an ongoing project. The frequency of basin clean out is a function of basin capacity and rate of sludge/ash generation.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are $221,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Substation Pollutant Discharge Prevention & Removal - O&M
Project No. 19a, 19b, 19c

Project Description:
Florida Statute Chapter 376 Pollutant Discharge Prevention and Removal requires that any person discharging a pollutant, defined as any commodity made from oil or gas, shall immediately undertake to contain, remove and abate the discharge to the satisfaction of the department. Florida Statute Chapter 403 holds it is prohibited to cause pollution so as to harm or injure human health or welfare, animal, plant, or aquatic life or property. This project includes the prevention and removal of pollutant discharges at FPL substations and will prevent further environmental degradation. Additionally, remediation activities are ongoing at seven substations located in Miami-Dade County and the encapsulation of lead-based paint on certain substation equipment which adheres to county regulations as defined in municipal codes.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
FPL's leak repair and regasketing work activities of oil-filled equipment have been fairly steady for the first two quarters. Major regasketing work was performed on transformers at the Martin Power Plant and Midway Substation. However, the difficulties in obtaining equipment clearances during the summer months to perform leak repair work due to high output demand from the hot weather will hinder progress. But, it is anticipated the work will increase in the last quarter once cooler weather arrives. Equipment encapsulation work is planned for two units in 2011. However, there are tentative plans that one of the units will be entirely replaced this year. Environmental remediation work continues at six substations located in Miami-Dade County due to various degrees of arsenic contamination. Major remediation work to clean-up the arsenic-impacted groundwater at the University and Princeton Substations is on track for this year. Arsenic-impacted soil hotspot removals and/or institutional controls are planned for the other four substations. But the waiting for approvals and permits from the county's environmental agency, Department of Environmental Resources Management ("DERM"), has caused delays in the some of the work which will push the work forward into next year. The lead that has been previously reported has been addressed and is no longer an issue.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)

- 19a. Project expenditures are estimated to be $435,512 or 13.4% lower than previously projected. The variance is primarily due to delays in the arsenic remediation work planned at the University, Princeton, Coconut Grove, Cutler, Lawrence, and Perrine substations located in Dade County, under the direction of the Department of Environmental Resources Management ("DERM"). Delays were encountered in securing approvals from DERM and city permits to proceed with source removal activities at five of the substations, and installation of a portable groundwater treatment system at the University substation. Source removal activities and installation of the portable groundwater treatment system are expected to be completed in 2012.
- 19b. Project expenditures are estimated to be $690,458 or 83.9% higher than previously projected. The variance is primarily due to unexpected major regasketing work performed on leaking transformers at the Martin Plant and Midway Substation. In addition, these transformers required additional oil processing to reduce the high moisture content due to the leaks.
- 19c. No variance expected.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
The equipment leak repair and regasketing work continues. The arsenic in soils and/or groundwater continues to be addressed at six substations located in Miami-Dade County. A groundwater treatment system to clean-up the arsenic-impacted groundwater at the University and Princeton Substations is on track for this year. The closure of one substation (i.e., Overtown Substation) previously reported last year was delayed until this year due to delays in county approvals to obtain a restrictive covenant.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are:

- 19a $2,819,714
- 19b $985,429
- 19c ($560,232)

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Wastewater/Stormwater Discharge Elimination & Reuse - O&M**
Project No. 20

Project Description:
Pursuant to 33 U.S.C. Section 1342 and 40 CFR 122, FPL is required to obtain NPDES permits for each power plant facility. The last permits issued contain requirements to develop and implement a Best Management Practice Pollution Prevention Plan (BMP3 Plan) to minimize or eliminate, whenever feasible, the discharge of regulated pollutants, including fuel oil and ash, to surface waters. In addition, the 1997 Federal Ambient Water Quality Criteria requires FPL to meet surface water standards for any wastewater discharges to groundwater at all plants, and the Dade County DERM requires the Turkey Point and Cutler plants' wastewater discharges into canals to meet county water quality standards found in Section 24-11, Code of Metropolitan Dade County.

In order to address these requirements, FPL has undertaken a multifaceted project which includes activities such as ash basin lining, installation of retention tanks, tank coating, sump construction, installation of pumps, motor, and piping, boiler blowdown recovery, site preparation, separation of stormwater and ashwater systems, separation of potable and service water systems, and the associated engineering and design work to implement these projects.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
The project is on hold due to the Pt. Everglades ESP Project.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project expenditures are estimated to be $0.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
The project is on hold due to the Pt. Everglades ESP Project.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are $0.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: St. Lucie Turtle Net – O&M
Project No. 21

Project Description:
FPL is limited in the number of lethal turtle takings permitted at its St. Lucie Power Plant by the Incidental Take Statement contained in the Endangered Species Act Section 7 Consultation Biological Opinion, issued to FPL on May 4, 2001 by the National Marine Fisheries Service ("NMFS"). The number of lethal takings permitted in a given year is calculated by taking one percent of the total number of loggerhead and green turtles captured in that year. The Incidental Take Statement separately limits the number of lethal takings of Kemp's Ridley turtles to two per year over the next ten years, and the number of lethal takings of either hawksbill or leatherback turtles to one of those species every two years over the next ten years. An effective 5-inch primary barrier net is vital to limiting the number of lethal turtle takes per year. In 2002, the existing net became deformed due to the influxes of jellyfish and algae entering the canal. With the Commission approval, a replacement and enhancement of the net system was performed. In 2007, the antifoulant and protective coating on the existing 5-inch net deteriorated and was experiencing UV damage. With Commission approval, FPL purchased and installed a new 5-inch net in 2009.

In October 2009, the 5-inch primary barrier net failed due to influxes of algae that entered the canal and created a blockage of approximately 80% of the net. The net is currently in a temporary configuration, which has created an effective temporary barrier for turtles. The Turtle Net project now requires the engineering, construction and installation of a more robust barrier structure that can withstand significant algal events and similar environmental challenges. The proposed design would include the removal of the damaged piles and installation of new piles and a support structure to effectively secure the net.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
Engineers have proposed a design for a more effective barrier structure.

Project Fiscal Expenditures:
(January 1, 2011– December 31, 2011)
Project expenditures are estimated to be $0.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
Engineering vendor to be selected and drawings received by December 31, 2011. Site certification approval process to commence. The current net will remain in a temporary configuration until the new structure is constructed. Engineering of the structure will continue through 2011 and into first quarter of 2012.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are $0.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Pipeline Integrity Management (PIM) – O&M**
Project No. 22

Project Description:
FPL is required to develop a written pipeline integrity management program for its hazardous liquid / gas pipelines. This program must include the following elements: (1) a process for identifying which pipeline segments could affect a high consequence area; (2) a baseline assessment plan; (3) an information analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure; (4) the criteria for determining remedial actions to address integrity issues raised by the assessments and information analysis; (5) a continual process of assessment and evaluation of pipeline integrity; (6) the identification of preventive and mitigative measures to protect the high consequence area; (7) the methods to measure the program's effectiveness; (8) a process for review of assessment results and information analysis by a person qualified to evaluate the results and information; and, (9) record keeping.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
The ongoing integrity assessments were undertaken for the corporate liquid/gas pipelines along with associated evaluations and appropriate countermeasures. Smart Pigging of the TMR-30 pipeline is scheduled for 3Q2011 which will require both confirmatory and remedial repairs on that pipeline. The low earthen cover on the TMT 16 inch pipeline was risk ranked and remedial action is planned for two (2) known areas of no topsoil coverage by end of 2011. Further remedial actions are required in 2012 and 2013 to address the remaining higher risk locations. Annual Public Awareness Campaign was improved and conducted. We have added newly identified DOT Jurisdictional pipelines from our Sanford Plant into the 2011 public outreach effort.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project expenditures were $10,392 or 4.6% higher than previously projected.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
Inline inspection projects on TMR 30 inch and TMT 16 inch pipelines are in progress. PII/GE was awarded. Tentative schedule for pigging TMT 16 inch pipeline with geometry and H/R MFL tool is August 4 & 6 and for TMR 30 inch pipeline with Combo tool (geometry & MFL tools all on one vehicle), 25 August. Confirmatory digs will be performed after obtaining the tools' data on both TMR 30 inch & TMT 16 inch pipelines. Pipeline Awareness Program (PAP) mail out is underway and as a part of the PAP program a 811 logo will be installed on TMR Tank 1271/B facing I-95 south band in first week of August, 2010.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are $476,500.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

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

Project Description:
The EPA first established the SPCC Program in 1973 when the agency issued the Oil Pollution Prevention Regulation (i.e., SPCC rule) to address the oil spill prevention provisions contained in the Federal Water Pollution Control Act of 1972 (later amended as the Clean Water Act). The purpose of the regulation was to prevent discharges of oil from reaching the navigable waters of the U.S. or adjoining shorelines and to prepare facility personnel to respond to oil spills. The SPCC regulation requires certain facilities to prepare and implement SPCC Plans and address oil spill prevention requirements including the establishment of procedures, methods, equipment, and other requirements to prevent discharges of oil as described above. Specifically, the rule applies to any owner or operator of a non-transportation related facility that:

- Has a combined aboveground oil storage capacity of more than 1,320 gallons, or a total underground oil storage capacity exceeding 42,000 gallons (Note: the underground storage capacity does not apply to those tanks subject to all of the technical requirements of the federal underground storage tank rule found in 40 CFR 280 or a State approved program); and

- Due to its location, could be reasonably expected to discharge oil in quantities that may be harmful into or upon the navigable waters of the United States or adjoining shorelines.

  In January 1988, a large storage tank owned by Ashland Oil Company at a site in western Pennsylvania collapsed, releasing approximately 750,000 gallons of diesel fuel to the Monongahela River. Following calls for new tank legislation, an EPA task force recommended expanded regulation of aboveground tanks within the framework of existing legislative authority. The result was EPA's SPCC rulemaking package, the first phase of which was proposed in 1991. Due to a series of agency delays primarily resulting from the 1989 Exxon Valdez oil spill that required EPA to issue the Facility Response Plan rule under the Oil Pollution Act of 1990, the final SPCC Rule was not published until July of 2002. A deficiency was found at the St, Lucie Unit 2 Diesel Oil Storage Tank and refueling tank areas. In order to meet compliance regulations, these areas are required to have secondary containment systems installed. For compliance, it is necessary to install oil berms, designed to catch any spilled oil upon delivery, in these areas.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
FPL is continually updating the SPCC plans for 625 substations. The updates are required to maintain compliance when oil-filled equipment is relocated, removed, upgraded, or added to the substation. Oil diversionary structures are being repaired and new structures are being installed at certain substations. We are currently using alternative oil diversionary products such as interlocking plastic sheeting and polymer-filled booms to provide a more effective and long lasting means to contain oil releases. Inspections of all substations, which are required by SPCC regulations, are being performed on a quarterly basis with the information being captured in a complex database.

The berm at the St. Lucie plant, which is used to catch any spilled oil upon delivery, was completed early 2011. The project was scheduled to complete in 2010, but due to required concrete cure time, coatings work rolled to 2011.

FPL is continually updating the Facility Response Plans for all electrical power plants and terminals. These updates incorporate changes to equipment and containment throughout the year.

FPL repaired the Metering Tank containment wall cracks at the Manatee Plant in July 2011 because the cracks created a structural integrity risk for the containment around the fuel oil metering tanks.

FPL repaired the Tank farm earthen berm at the Martin Terminal in May 2011. Erosion on the exterior slope of the earthen containment berm was repaired with new fill and stabilized accordingly

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project expenditures are estimated to be $173,171 or 19.3% higher than previously projected. The variance is primarily due to more oil diversionary structure repairs identified during SPCC inspections than had been anticipated.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
The updating of the 625 substation SPCC plans is ongoing. FPL continues to work on planning and conceptual engineering for additional facility upgrades. Additionally, due to the large number of quarterly substation inspection reports that are being generated, FPL is continuously using a complex database to manage all SPCC-required information. This database has proven to be an efficient and effective method of gathering information to identify compliance issues that need to be addressed. FPL continues to explore new automated methods to be proactive in maintaining SPCC compliance.

FPL is continually updating the Facility Response Plans for all electrical power plants and terminals. These updates incorporate changes to equipment and containment throughout the year to maintain SPCC regulation compliance.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are $953,190.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Manatee Reburn – O&M
Project No. 24

Project Description:
This project involves installation of reburn technology in Manatee Units 1 and 2. Reburn is an advanced nitrogen oxides (NOx) control technology that has been developed for, and applied successfully in, commercial applications to utility and large industrial boilers. The process is a proven advanced technology, with applications of a reburn-like flue gas incineration technique dating back to the late 1960s, and developments for applications to large coal fired power plants in the United States dating back to the early to mid 1980s.

Reburn is an in-furnace NOx control technology that employs fuel staging in a configuration where a portion of the fuel is injected downstream of the main combustion zone to create a second combustion zone, called the reburning zone. The reburning zone is operated under conditions where NOx from the main combustion zone is converted to elemental nitrogen (which makes up 79% of the atmosphere). The basic front wall-fired boiler reburning process divides the furnace into three zones.

In the 1996-97 time period, FPL invested considerable effort evaluating the Manatee Units for the application of reburn technology. FPL has recently reviewed the reburn system designs previously proposed for the Manatee units, and concluded that a design for either oil or gas reburn would require very similar characteristics. This will require reburn fuel injectors to be located at the elevation of the present top row of burners, with reburn injectors on the boiler front and rear walls. For the present application the injectors will be required to have a dual fuel (oil and gas) capability. In order to provide adequate residence time for the reburn process, it is proposed to locate the reburn overfire air (OFA) ports between the boiler wing walls and to angle them slightly to provide better mixing with the boiler flow. Because of the complexity of the boiler flow field and the port location, it was determined that OFA booster fans would be required to assist the air-fuel mixing and complete the burnout process. Installation of reburn technology for Manatee Units 1 and 2 offers the potential to reduce NOx emissions through a "pollution prevention" approach that does not require the use of reagents, catalysts, and pollution reduction or removal equipment. FDEP and FPL agree that reburn technology is the most cost-effective alternative to achieve significant reductions in NOx emissions from Manatee Units 1 and 2.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
The units continue to operate reliably and minor tuning of the process continues. The systems have achieved significant NOx emission reductions. The PMT Reburn O&M ECRC dollars cover all on-going burner and equipment maintenance costs associated with the project.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project expenditures are estimated to be $102,856 or 20.6% higher than previously projected. The variance is primarily due to higher than expected costs associated with repair and replacement of burner assemblies that were identified during recent planned outages. Most of the work was completed in the spring, and the remaining work is scheduled to be completed during the Fall of 2011.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
Unit 1 & Unit 2 are operating as referenced above. Final report has been presented to the DEP. FDEP has accepted FPL's proposed limits and the project is now complete. Project expenditures are based on runtime and available maintenance time.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are $900,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Pt. Everglades ESP Technology – O&M**
Project No. 25

Project Description:
The requirements of the Clean Air Act direct the Environmental Protection Agency to develop health-based standards for certain "criteria pollutants". i.e. ozone (O3), sulfur dioxide (SO2), carbon monoxide (CO), particulate matter (PM), nitrogen oxides (NOx), an lead (Pb). EPA developed standards for the criteria pollutants and regulates the emissions of those pollutants from major sources by way of the Title V permit program. Florida has been granted authority from the EPA to administer its own Title V program which is at least as stringent as the EPA requirements. Florida is able to issue, renew and enforce Title V air operating permits for sources within the state via 403.061 Florida Statutes and Chapter 62-213 F.A.C., which is administered by the State of Florida Department of Environmental Protection ("DEP"). The Title V program addresses the six criteria pollutants mentioned earlier, and includes hazardous air pollutants (HAP). The EPA sets the limits of emissions of Hazardous Air Pollutants through the Maximum Achievable Control Technology (MACT). The original Port Everglades Title V permit, issued in 1998, expired in 2003. The renewal permit issued January 1, 2004 is now expiring December 31, 2008. A renewal permit application has been submitted and is pending DEP review. The DEP's Title V permit for FPL Port Everglades plant requires FPL to install and maintain Electrostatic Precipitators at all four Port Everglades units to address local concerns and to insure compliance with the National Ambient Air Quality Stands and the EPA MACT Standards.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
The ESP engineering design for Units 1–4 was completed in 2004. All four units' ESPs were completed between 2005 and 2007 and are operational (O&M activities started in April 2005 for this project).

The installation of the new Kirk Key Interlock System for both Units 3 and 4 will be completed in 2011. The Key interlock system for both Units 1 and 2 was installed in 2010.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project expenditures are estimated to be $449,118 or 224.6% higher than previously projected. The variance is primarily due to the early removal of Port Everglades Units 3 and 4 from inactive reserve. As a result of projected reduction in load demand, planned outage schedules and available capacity, FPL planned to place the units in an inactive reserve status, where the units would be maintained for return to service at a future date if necessary. As a result of revisions to the 2011 and 2012 planned outage schedule and a revised system demand forecast, FPL determined that returning units to service earlier than originally planned was the most cost effective option. As a result, additional activities such as the installation of an ESP Keys Interlock System and maintenance were necessary for continued operation of the units.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
Construction on all four ESPs was completed and all four units ESPs are operational.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are $640,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **UST Replacement/Removal – O&M**
Project No. 26

Project Description:
The Florida Administrative Code (FAC) Chapter 62-761.500, dated July 13, 1998, requires the removal or replacement of existing Category-A and Category-B storage tank systems with systems meeting the standards of Category-C storage tank systems by December 31, 2009. UST Category-A tanks are single-walled tanks or underground single-walled piping with no secondary containment that was installed before June 30, 1992.
UST Category-B tanks are tanks containing pollutants after June 30, 1992 or a hazardous substance after January 1, 1994 that shall have a secondary containment. Small diameter piping that comes in contact with the soil that is connected to a UST shall have secondary containment if installed after December 10, 1990.
UST and AST Category-C tanks under F.A.C. 62-761.500 are tanks that shall have some or all of the following; a double wall, be made of fiberglass, have exterior coatings that protect the tank from external corrosion, secondary containment (e.g., concrete walls and floor) for the tank and the piping, and overfill protection.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
There were no activities in 2011.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project expenditures are for 2011 are $0.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
Initial review of the scope of work has been completed.

Project Projections:
(January 1, 2012 to December 31, 2012)
There are no activities planned for 2012.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Lowest Quality Water Source (LQWS) – O&M
Project No. 27

Project Description:
Section 366.8255 of the Florida Statutes provides for the recovery through the ECRC of "environmental compliance costs" which are costs incurred in complying with "environmental rules or regulations." The LQWS Project is required in order to comply with permit conditions in the Consumptive Use Permits (CUPs) issued by the St. Johns River Water Management District (SJRWMD or the District)) for the Sanford Plant. Those permit conditions are intended to preserve Florida's groundwater, which is an important environmental resource. The permit conditions therefore "apply to electric utilities and are designed to protect the environment" as contemplated by section 366.8255. The SJRWMD adopted a policy in 2000 that, upon permit renewal, a user of the District's water is required to use the lowest quality of water that is technically, environmentally and economically feasible for its needs. This policy was implemented for the Sanford Plant in the current CUPs. For the Sanford facility, Condition 15 of CUP No. 9202, issued in June 2000, requires the lowest quality of water to be used that is feasible to meet the needs of the facility. The LQWS project at Sanford Plant is currently operational.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
The project at the Sanford Plant is currently operational.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
O&M project expenditures are estimated to be $5,861 or 1.8% lower than originally projected.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
The project at the Sanford Plant is currently operational.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are $329,710.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **CWA 316(b) Phase II Rule – O&M**
Project No: 28

Project Description:
The Phase II Rule implements section 316 (b) of the Clean Water Act (CWA) for certain existing power plants that employ a cooling water intake structure and that withdraw 50 million gallons per day (MGD) or more of water from rivers, streams, lakes, reservoirs, estuaries, oceans or other Waters of the United States (WUS) for cooling purposes. The Phase II Rule establishes national requirements applicable to, and that reflect the best technology available (BTA) for the location, design, construction and capacity of existing cooling water intake structures (CWIS) to minimize adverse environmental impacts. The Phase II Rule has implications at the following FPL facilities: Cape Canaveral, Cutler, Fort Myers, Lauderdale, Port Everglades, Riviera, Sanford, Martin, Manatee and St. Lucie Power Plants.

A new proposed 316(b) Rule entitled Cooling Water Intake Structures at Existing and Phase I facilities (Existing Facilities Rule) was published in the Federal Register on April 20, 2011. A Consent Decree requires EPA to sign the final Existing Facilities Rule by July 27, 2012 and, assuming this occurs, the final rule will become effective in October, 2012. The Existing Facilities Rule, as proposed, will regulate cooling water intake structures from power plants and industries that withdraw threshold limits of cooling water from waters of the U.S. The rule requirements are designed to reduce adverse environmental impacts that result from the impingement and entrainment of aquatic organisms by requiring facilities to install Best Technology Available to reduce the impacts to cooling water intakes.

The Existing Facilities Rule replaces the previous 316(b) Phase II Rule for Existing Facilities (Phase II Rule), that was issued in 2004 and challenged by environmental groups and six northeastern states. The Phase II Rule was subsequently remanded to the EPA by the Second Circuit Court of Appeals after aspects concerning cost to benefit analysis were ruled upon by the U.S. Supreme Court.

FPL's current CWA 316(b) Phase II Project was approved by the Commission in Order No. PSC-04-0987-PAA-EI, issued on October 11, 2004. The project included the recovery of costs associated with work required to respond to EPA requirements that facilities covered by the Phase II Rule complete and submit Comprehensive Demonstration Studies to determine the effect of cooling water intake structures on aquatic life. Additionally, in 2008, Order No. PSC-08-0775-FOF-EI approved the recovery of legal and consulting activities associated with protecting the interests of FPL and its customers in the Phase II Rule development. The cost for these activities was projected to be $525,000. To date, however, FPL has not had to spend any of this projected amount because we have been able to work within the Utility Water Act Group and the Edison Electric Institute to have the Supreme Court rule on the 316 (b) Phase II Rule without assistance from outside consultants or outside legal counsel retained by FPL.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
Comments on the Existing Facilities Rule are due to EPA on August 18, 2011. Because of the relatively short time frame to develop and submit comments, the amount of detail in the Rule, and the large potential financial impact to FPL and its customers if the Rule is not favorable, FPL felt it was prudent to retain the services of a qualified consultant to assist in developing comments.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project expenditures were $7,671 or 5.9% lower than previously projected.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
FPL's comments are virtually completed and ready to submit to EPA.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are $1,183,091.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **SCR Consumables - O&M**
Project No. 29

Project Description:
The Manatee Unit 3 and Martin Unit 8 Expansion Project Final Orders of Certification under the Florida Power Plant Siting Act and the PSD Air Construction Permit require the installation of SCRs on each of the plants' four Heat Recovery System Generators (HRSG) for the control of nitrogen oxide (NOx) emissions. The Florida Department of Environmental Protection (FDEP) made the determination that the SCR system is considered Best Available Control Technology (BACT) for these types of units, with concurrence from the U.S. Environmental Protection Agency (EPA). The operation of the SCRs will cause FPL to incur O&M costs for certain products that are consumed in the SCRs. These include anhydrous ammonia, calibration gases, and equipment wear parts requiring periodic replacement such as controllers, ammonia detectors, heaters, pressure relief valves, dilution air blower components, NOX control analyzers and components.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
The SCR systems are operational on both Manatee Unit 3 and Martin Unit 8.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project expenditures were $16,737 or 4.2% lower than previously projected.

Project Progress Summary:
(January 1, 2011 December 31, 2011)
The SCR systems are operating reliably on both Manatee Unit 3 and Martin Unit 8.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are $350,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Hydrobiological Monitoring Program (HBMP) - O&M
Project No. 30

Project Description:
The Hydrobiological Monitoring Program is required by the Water Management District in the Conditions of Certification for Manatee Unit 3. The program involves the data collection of river chemistry, flow and vegetation conditions to demonstrate that the plant's withdrawals do not impact the environment in and along the river. The Hydrobiological Monitoring Program is a 10 year study which started in 2003 during the construction phase of Unit 3 and will be completed in 2013.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
Continue with river monitoring, calibration, maintenance and data collection. Vegetative mapping, aerial photography and mapping will be conducted during the fall of 2011, for reports due in 2013. A Data Summary Report was completed in March 2011.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project expenditures were $2,459 or 7.5% lower than previously projected.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
This is an ongoing project.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are $35,652.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **CAIR – O&M**
Project No. 31

Project Description:
In response to the EPA Clean Air Interstate Rule (CAIR), FPL initiated the CAIR Project to implement strategies to comply with Annual and Ozone Season NOx and SO2 emissions requirements. The CAIR project to date has included the Black & Veatch (B&V) study of FPL's control and allowance management options, an engineering study conducted by Aptech for the reliable cycling of the 800 MW units, the costs for the operation of SCR's constructed on SJRPP Units 1 and 2, costs for the operation of the Scrubber and SCR being installed on Scherer Unit 4, and the installation of CEMS for the peaking gas turbine units. The 800 MW Cycling Project was added to CAIR after 2006 submittal. Aptech Engineering provided engineering services for the first phase of a multiphase scope of work that will assure that the operating reliability is maintained in a cycling mode. The study costs to Aptech Engineering have been paid and a significant portion of the work has been completed on the Martin and Manatee 800 MW units. Several countermeasures that were prioritized and scheduled for implementation in 2008 – 2011. The CEMS installation on the Gas Turbine Peaking Units has been completed with ongoing maintenance expenses for their operation. On December 3, 2008 Georgia EPD promulgated the GA Multi-Pollutant rule requiring installation of SCR and a Scrubber on Scherer Unit 4. Recently, on July 6, 2010, EPA proposed the Transport Rule, which will leave requirements to comply with the CAIR regulations in place until 2012 when a new program will be implemented to further reduce So2 and NOx emissions from fossil power plants.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
800MW Cycling Project - The A and B Boiler Feed Pump recirculation regulators were inspected at Martin 2. Martin has removed the isolation valves on the Controlled Extraction, valves on the Mass Blowdown Automation, as well as the control valves on the Spray Upgrades. The Water Induction Protection bridal piping was removed at Martin. Manatee 1 has had these projects installed. Manatee 1 also had the A and B BFP recirculation valves replaced. Three throttle valves were shipped off for refurbishment and SPE coating and returned. The Water Treatment Plant lease payments have started for both Martin and Manatee.

St. John's River Power Park (SJRPP) 1&2 SCR construction is in progress and Scherer FGD and SCR estimated completion is for the first half of 2012.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project expenditures are estimated to be $292,239 or 15.3% lower than previously projected. The variance is primarily due to lower than expected expenses associated with the legal challenges to the CAIR rulemaking. The U.S. Circuit Court of Appeals vacated CAIR but remanded the rule and ordered EPA to promulgate a new rule that conformed to the Court's opinion. FPL had anticipated additional legal costs to ensure EPA promulgated a replacement rule within a timely period. On July 6, 2011, EPA promulgated the Cross-State Air Pollution Rule to replace the Clean Air Interstate Rule. FPL is currently evaluating the rule and has not yet decided whether a legal challenge of the replacement rule needs to be pursued. In addition, there was lower than anticipated ammonia consumption for the Selective Catalytic Reduction's (SCR) at SJRPP. This variance was partially offset by higher than expected common O&M costs at the FGD facilities and limestone handling areas.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
As part of the 800 MW Cycling project the A and B Boiler Feed Pump recirculation regulators were inspected at Martin 2 and Manatee 1. Martin 2 and Manatee 1 have removed the isolation valves on the Controlled Extraction, valves on the Mass Blow-down Automation, as well as the control valves on the Spray Upgrades. The Water Induction Protection bridal piping was removed at Martin 2 and Manatee 1. Lease payments for the water treatment plant additions required at both Manatee and Martin have begun.

FPL's CAIR project at SJRPP U1 & 2 continues with both SCRs in operation. O&M expenses for reagents and maintenance will be ongoing. FPL's share of O&M costs associated with the CAIR Scrubber and SCRs at plant Scherer will occur starting in 2011 as common plant facilities are placed in service. Unit specific O&M expenses will occur when the construction is completed 2012.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are $4,652,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **BART Project – O&M**
Project No. 32

Project Description:
Conduct air dispersion modeling to determine the visibility impacts to Federally Mandated Class 1 Areas (National Parks, National Wilderness Areas, etc.) from FPL's BART-Eligible units. The Regional Haze Rule, renamed the Clean Air Visibility Rule, (CAVR) mandates that certain vintage electric generating units (ca. 1962-1977) install Best Available Retrofit Technology (BART) if it is shown, via modeling that a unit causes or contributes to visibility impairment in any Class 1 Area.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
- Compile Emissions Inventory of BART-Eligible sources – Complete May 2006
- Perform modeling - First round complete June 2006
- Conduct BART Control Technology Analysis – Pending
- Prepare and submit BART Application Packages – Complete Fall 2006

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project expenditures are estimated to be $0.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
BART application for exempt facilities (PCC, PMR, PMT, PPE, PRV) submitted to FDEP on January 31, 2007. BART determination for PTF was submitted to the FDEP. FDEP requested additional information on PTF February 26, 2007, which necessitated additional Golder support. Response to FDEP with additional information submitted to FDEP May 3, 2007. FPL and FDEP successfully negotiated the terms of the Draft BART permit for PTF Units 1 and 2 with FPL receiving the final permit on April 14, 2009. The terms of the permit will become effective in 2013.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are $0.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: CAMR Compliance– O&M
Project No. 33

Project Description:
The Clean Air Mercury Rule (CAMR) was promulgated by the Environmental Protection Agency (EPA) on March 15, 2005, imposing nation-wide standards of performance for mercury (Hg) emissions from existing and new coal-fired electric utility steam generating units. The CAMR is designed to reduce emissions of Hg through implementation of coal-fired generating unit Hg controls. In addition, CAMR requires the installation of Hg Continuous Emission Monitoring Systems (HgCEMS) to monitor compliance with the emission requirements. The rule is implemented in two phases with an initial compliance date of 2010 for Phase I and the final required reductions of Phase II in 2018. The State of Florida has begun the implementation of the requirements for reduction of Hg through rule making process. Plant St. John's River Power Park (SJRPP) Units 1 & 2, in which FPL has 20% ownership shares, are affected units under this rule and will require the installation of Hg controls and HgCEMS. Similarly, the State of Georgia has also begun their rule making process to implement the federal rule, which will affect FPL's ownership share of Plant Scherer Unit 4, also requiring the installation of HgCEMS and Hg controls.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
The Scherer Unit 4 baghouse was placed into service April 4, 2010. The baghouse passed all performance guarantee tests in May 2010 and is now in continuous operation.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project expenditures are estimated to be $1,567,442 or 40.2% lower than previously projected. The variance is primarily due to a decrease in consumption of Powdered Activated Carbon (PAC) needed to meet the Georgia EPD requirements for mercury removal in the operation of the Scherer baghouse. Detuning the precipitators and allowing more fly ash to mix with the PAC injected into flue gases resulted in a decreased amount of PAC injection needed for effectively removing mercury.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
The FPL CAMR project at Plant Scherer includes FPL's costs from the installation of the baghouse, the mercury sorbant injection system with associated controls and material handling equipment, and capital additions to Plant Scherer common areas to accommodate sorbant delivery and storage and spent sorbant disposal. Hg controls at Plant Scherer were installed on all four units at the plant to comply with the Georgia Multi-Pollutant Rule. Installation of controls requires a specific sequence for the construction of the controls and material handling systems. The baghouse on Unit 4 was installed and placed in-service in April 2010. Ongoing O&M costs associated with the CAMR Compliance project include expenses associated with purchase of sorbant used for flue gas Hg removal and disposal of spent sorbant.

Project Projections:
(January 1, 2012 - December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are $3,291,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: St. Lucie Cooling Water System Inspection and Maintenance – O&M
Project No. 34

Project Description:
The purpose of the proposed St. Lucie Plant Cooling Water System Inspection and Maintenance Project (the "Project") is to inspect and, as necessary, maintain the cooling water system (the "Cooling System") at FPL's St. Lucie nuclear plant , such that it minimizes injuries and/or deaths of endangered species and thus helps FPL to remain in compliance with the federal Endangered Species Act, 16 U.S.C. Section 1531, et seq. (the "ESA") The St. Lucie Plant is an electric generating station on Hutchinson Island in St. Lucie County, Florida. The plant consists of two nuclear-fueled 850 net MWe units, both of which use the Atlantic Ocean as a source of water for once-through condenser cooling. This cooling water is supplied to the units via the Cooling System. The St. Lucie Plant cannot operate without the Cooling System. Compliance with the ESA is a condition to the operation of the St. Lucie Plant. Inspection and cleaning of the intake pipes is an "environmental compliance cost" under section 366.8255, Florida Statutes. The specific "environmental law or regulation" requiring inspection and cleaning of the intake pipes are terms and conditions that will be imposed pursuant to a Biological Opinion ("BO") that is to be issued by the National Oceanic and Atmospheric Administration ("NOAA") pursuant to section 7 of the ESA. It is anticipated that NOAA will finalize the BO in 2011. NOAA sent the Nuclear Regulatory Commission ("NRC") a letter dated December 19, 2006, confirming its intent to issue the BO and stating the requirements that will be imposed pursuant to the BO with respect to inspection and cleaning of the intake pipes.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
Cleaning (O&M) of the 12' north intake pipe and velocity cap vertical section was completed in 2011 and concrete removal (Capital) at the south and north velocity cap windows was completed in 2011.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project expenditures are estimated to be $506,676 or 307.1% higher than previously projected. The variance is primarily due to a longer outage duration that allowed for pipe cleaning activities to be performed in 2011 that were originally projected for 2012.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
The cleaning of all three (3) intake pipes and velocity cap vertical sections and the concrete removal at all three (3) velocity caps (for the installation of the turtle excluders) has now been completed for the project.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are $0.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Martin Plant Water System – O&M**
Project No. 35

Project Description:
The Martin Drinking Water System (DWS) is required to comply with the requirements the Florida Department of Environmental regulations rules for drinking water systems. The Florida Department of Environmental Protection (FDEP) determined the system must be brought into compliance with newly imposed drinking water rules for TTHM (trihalomethanes) and HAA5 (Haleo Acetic Acid). The upgrades to the potable water system will cause FPL to incur capital costs for major component upgrades to the system in order to comply with the new requirements. These include Nano filtration, air stripping, carbon and multimedia filtration. The operation of the potable system will cause FPL to incur O&M costs for certain products that are consumed during the water treatment process. These include carbon and multimedia bed media and nano filtration media.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
The project has been implemented. The agency has inspected and approved system startup and testing. The system will continue to run throughout 2011. O&M dollars were expended on filter maintenance and expected until the end of 2011 and into 2012.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project expenditures are estimated to be $5,174 or 30.4% higher than previously projected. The variance is primarily due to more required cleanings of the potable drinking water system than originally expected as a result of an aging system.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
O&M dollars were expended on filter maintenance and expected until the end of 2010 and into 2011.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are $20,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Low Level Radioactive Waste – O&M**
Project No. 36

Project Description:
The Barnwell, South Carolina radioactive waste disposal facility is the only site of its kind presently available to FPL for disposal of Low Level Waste (LLW) such as radioactive spent resins, filters, activated metals, and other highly contaminated materials. The Barnwell facility ceased accepting LLW from FPL June 30th, 2008. This project will construct a LLW storage facility for class B and C radioactive waste at the St. Lucie Plant (PSL). Turkey Point (PTN) will be implementing a similar project; however the PTN project will start later than the PSL project since PTN has some limited existing LLW storage capacity. Where practical, this project will be implemented as part of a fleet approach. The objective at PSL and PTN is to ensure construction of a LLW storage facility with sufficient capacity to store all LLW B and C class waste generated at each plant site over a 5 year period. This will allow continued uninterrupted operation of the PSL and PTN nuclear units until an alternate solution becomes available. The LLW on site storage facilities at PSL and PTN will also provide a "buffer" storage capacity for LLW even if an alternate solution becomes feasible, should the alternate solution be delayed or interrupted at a later date.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
The Turkey Point Level 1 project schedule has been created. The engineering vendor is currently conducting soil testing and preliminary engineering work is progressing with a 90% package delivery scheduled in late August 2011. Construction is expected to begin in October 2011 and the building should be completed by March 2012.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
No variance is expected. There are no project expenditures projected for 2011.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
The LLW Project at St. Lucie has experienced some additional schedule delays due to the competition for resources caused by the extended St. Lucie Unit 1 Cycle 23 refueling outage. This has resulted in delaying the completion of the facility from 3rd quarter 2010 to August 2011.

The St. Lucie LLW schedule delay has shifted some of the projected 2010 expenditures for the construction work into 2011. The Turkey Point LLW project is expecting completion in March 2012. Turkey Point LLW is behind schedule due to delays experienced at St. Lucie LLW competing for common resources.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are $0.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **DeSoto Next Generation Solar Energy Center – O&M**
Project No. 37

Project Description:
The DeSoto Next Generation Solar Energy Center ("DeSoto Solar") project is a zero greenhouse gas emitting renewable generation project, which on August 4, 2008, the Commission found in Order Number PSC-08-0491-PAA-EI, to be eligible for recovery through the ECRC pursuant to House Bill 7135. The DeSoto Solar project is a 25 MW solar photovoltaic generating facility which will convert sunlight directly into electric power. The facility will utilize a tracking array that is designed to follow the sun as it traverses through the sky. In addition to the tracking array this facility will utilize cutting edge solar panel technology. The project will involve the installation of the solar PV panels and tracking system and electrical equipment necessary to convert the power from direct current to alternating current and to connect the system to the FPL grid.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
Through end of June, 2011, Desoto's net energy production was 27,128 MWHs versus an expected energy production of 29,102 MWHs. The shortfall of energy production is attributed to an underground fault of the main feeder cable between Desoto and Sunshine Substation. This caused the solar site to be off line for 9 days. The cause of the cable fault is attributed to improper installation during construction. Accomplishments for the year include: implementation of reactive power (VARs) generation capability, implementation of remote start/stop control of the inverters, repair and redesign of drainage system to prevent erosion, development of an improved method to detect PV module string outages, and completing construction of administration building.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project expenditures are estimated to be $68,780 or 6.6% lower than previously projected. The variance is primarily due to lower than expected payroll and related expenses. Plant performance and improvements in the plant's data monitoring system has reduced the need for overtime, technical support, and site management. Grounds maintenance costs were also slightly lower than projected, as erosion repair work is not expected to be required.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
Desoto achieved Commercial Operation on October 27, 2009 and Final Acceptance on April 27, 2010.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are $1,108,836.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Space Coast Next Generation Solar Energy Center – O&M
Project No. 38

Project Description:
The Space Coast Next Generation Solar Energy Center ("Space Coast Solar") project is a zero greenhouse gas emitting renewable generation project, which on August 4, 2008, the Commission found in Order Number PSC-08-0491-PAA-EI, to be eligible for recovery through the ECRC pursuant to House Bill 7135. The Space Coast Solar project is a 10 MW solar photovoltaic (PV) generating facility which will convert sunlight directly into electric power. The facility will utilize a fixed PV array oriented to capture the maximum amount of electricity from the sun over the entire year. The project will involve the installation of the solar PV panels and support structures and electrical equipment necessary to convert the power from direct current to alternating current and to connect the system to the FPL grid.

The Space Coast project also includes building a 900 KW solar PV facility at the Kennedy Space Center (KSC) industrial area. This 900 KW solar site will be built and operated and maintained by FPL as compensation for the lease of the land for the Space Coast Solar Site which is located on KSC property.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
Through end of June, 2011, Space Coast's net energy production was 10,018 MWHs versus an expected energy production of 9,830 MWHs. Accomplishments for the year include: implementation remote start/stop control of the inverters, configuration changes to increase power output of two containers, design modifications to switchyard to facilitate grounding for site clearances, and resolution of container salt filter deficiencies.

KSC 1 MW site operated well with no major issues. Through end of June, 2011, net energy production was 894 MWhs (expected generation production for this site were provided). Quarterly Operation and Maintenance reports were submitted to NASA in accordance with Lease Agreement between NASA and FPL.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project expenditures are estimated to be $96,375 or 15.4% lower than previously projected. The variance is primarily due to lower than expected payroll and related expenses. Plant performance and improvements in the plant's data monitoring system has reduced the need for overtime, technical support, and site management. Technology expenditures, contractor services, materials and supplies were all lower than projected due to conservative estimates based on Desoto operating experience. Space Coast continues to have less equipment issues due to the smaller size and fixed PV module design.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
Space Coast Solar Site achieved commercial operation on April 16, 2010 and Final Acceptance is expected by September 30, 2010.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are $597,856.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Martin Next Generation Solar Energy Center - O&M**
Project No. 39

Project Description:
The Martin Next Generation Solar Energy Center ("Martin Solar") project is a zero greenhouse gas emitting renewable generation project, which on August 4, 2008, the Commission found in Order Number PSC-08-0491-PAA-EI, to be eligible for recovery through the ECRC pursuant to House Bill 7135. The Martin Solar project is a 75 MW solar thermal steam generating facility which will be integrated into the existing steam cycle for the Martin Unit 8 natural gas-fired combined cycle power plant. The steam to be supplied by Martin Solar will be used to supplement the steam currently generated by the heat recovery steam generators. The project will involve the installation of parabolic trough solar collectors that concentrate solar radiation. The collectors will track the sun to maintain the optimum angle to collect solar radiation. The collectors will concentrate the sun's energy on heat collection elements located in the focal line of the parabolic reflectors. These heat collection elements contain a heat transfer fluid which is heated by the concentrated solar radiation to approximately 750 degrees Fahrenheit. The heat transfer fluid is then circulated to heat exchangers that will produce up to 75 MW of steam that will be routed to the existing natural gas-fired combined cycle Unit 8 heat recovery steam generators.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
Commercial Operation was achieved on December 10, 2010. In the first six months of operation, the plant generated approximately 23,225 MWH of equivalent steam.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project expenditures were $22,470 or 0.9% lower than previously projected.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
Commercial Operation was achieved on December 10, 2010. In the first six months of operation, the plant generated approximately 23,225 MWH of equivalent steam.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are $2,479,444.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Greenhouse Gas Reduction Program - O & M
Project No. 40

Project Description:
The purpose of FPL's proposed Electric Utility Greenhouse Gas (GHG) Reduction Program is to implement both the reporting and emission reduction requirements established under Chapter 403 of the Florida Statutes and to comply with the EPA Mandatory GHG Reporting Rule promulgated on October 30, 2009. During the initial implementation of the Florida program, electric utilities, major emitters of GHG's, are required to participate in The Climate Registry providing historical and current (GHG) emission data to establish the baseline emissions and targets for the required compliance reductions to meet the 2017, 2025 and 2050 deadlines. In subsequent years utilities will be required to engage third party verification of their reported inventory. To comply with future GHG Cap and Trade programs FPL will need to recover GHG emission allowance costs through this project as needed. To achieve the future reduction goals established by the executive order, FPL anticipates that additional reductions in its GHG emissions will be required beyond the currently planned fossil unit conversions, nuclear uprates, and the addition of new nuclear generating units. The additional reductions will likely require a combination of the implementation of carbon sequestration and storage technology and the use of verified carbon offset projects. EPA's Mandatory (GHG) Reporting Rule requires electric utilities to record emissions of GHGs, primarily CO2 from the combustion of fossil fuels, and report actual data in a subsequent year. FPL is required to report GHGs emitted from its fossil generating units annually beginning in 2011 (for its 2010 emissions).

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
FPL proposes to delay implementation of the Greenhouse Gas Reduction Program originally approved by the Commission, and its associated costs, and continues in its participation with the FDEP in its rule development. EPA has promulgated a final rule requiring the mandatory reporting of GHG's in which FPL is participating.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
There is no variance expected for this project.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
FPL has not yet joined The Climate Registry or prepared Registry required documentation for reporting historical data as identified in the FDEP program and as an allowable alternative, will comply with the EPA reporting requirements instead. FPL continues in its participation with the FDEP in its rule development workshops and anticipates that a final rule providing detailed requirements in 2011.

In preparation for the submittal of the required GHG report to EPA, FPL purchased a computer server and software for data collection in 2011. EPA extended the deadline for reporting for the 2010 GHG data from March to September 30, 2011.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are $60,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Manatee Temporary Heating System – O&M**
Project No. 41

Project Description:
FPL is subject to specific and continuing legal requirements to provide a warm water refuge for the endangered manatee at its Riviera (PRV) and Cape Canaveral Plants (PCC). FPL has undertaken the design, engineering, purchase, and installation of a temporary manatee heating system at both PRV and PCC ("the Project"). The Project is required pursuant to PRV's and PCC's Manatee Protection Plans (MPP), as part of the State Industrial Wastewater Facility Permit Numbers FL0001546, Specific Condition 13, issued on February 16, 1998 and FL0001473, Specific Condition 9, issued on August 10,2005, respectively. In order to comply with the respective MPP's, FPL's installation of a temporary manatee heating system at PRV and PCC will be implemented to avoid potential adverse impacts to manatees congregating at PRV's and PCC's manatee embayment area. Manatees currently gather at the plants during the annual period from November 15 to March 31 at PRV and the annual period of October 15 to March 31 at PCC. FPL's installation of the Manatee Temporary Heating System at each site must be implemented to provide warm water until the site has completed the planned modernization of the existing power generation units and return of warm water flow from the generating unit cooling water will be provided by operation of the new units.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
The Manatee Temporary Heating System at PRV began operations in Q4 2009 and was available throughout the 09/10 and 10/11 manatee season. The PCC Manatee Heating System work was completed in September 2010, and the unit was available throughout the 2010/2011 manatee season.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project expenditures are estimated to be $865,031 or 182.3% higher than previously projected. The variance is primarily due to higher than expected costs at the Cape Canaveral plant associated with design changes that were identified during the previous manatee heating season (Oct 2010 thru Mar 2011). FPL found that the initial 34 MMBTU electric heater was capable of maintaining a closed refuge at the required 68°F only when river temperatures remained at 55°F or above. During the last season, a supplemental heating system was leased and installed to provide additional heating capacity as a result of lower than expected river temperature. In addition to the operation of the electric heaters, operation of the rental equipment occurs on an as-needed basis to meet the 68°F refuge requirement. FPL plans to use a rental heater in conjunction with the existing electric heater during the upcoming season to meet the manatee protection requirements. The variance reflects the increased heater rental cost, as well as the light oil and contracted manpower necessary to run the unit.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
The Manatee Temporary Heating System at PRV began operations in Q4 2009 and was available throughout the 09/10 and 10/11 manatee season. The PCC Manatee Heating System work was completed in September 2010 and the unit was available throughout the 2010/2011 manatee season.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for January 2012 through December 2012 are $1,335,073.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Turkey Point Cooling Canal Monitoring Plan - O & M
Project No. 42

Project Description:
Pursuant to Conditions IX and X of the Florida Department of Environmental Protection's (FDEP) Final Order Approving Site Certification, filed October 29, 2008, FPL submitted its initial draft of the proposed Cooling Canal Monitoring Plan associated with FPL's Turkey Point Uprate Project to the South Florida Water Management District (SFWMD). This plan requires an assessment of baseline conditions to provide information on the vertical and horizontal extent of the hypersaline groundwater plume and effect of that plume on ground and surface water quality, if any. Comments, concerns and requests for revisions or action items were received from the SFWMD as well as the FDEP. Miami-Dade Department of Environmental Resource Management (DERM) has incorporated into the current draft the proposed monitoring plan, dated July 16, 2009.

The TP CCM Plan was finalized by FPL and the agencies on October 14, 2009. The objective of FPL's TP CCM Plan is to implement the Conditions of Certification IX and X, which states that "the Revised Plan shall be designed to be in concurrence with other existing and ongoing monitoring efforts in the area and shall include but not necessarily be limited to surface water, groundwater and water quality monitoring, and ecological monitoring to: delineate the vertical and horizontal extent of the hyper-saline plume that originates from the cooling canal system and to characterize the water quality including salinity and temperature impacts of this plume for the baseline condition; determine the extent and effect of the groundwater plume on surface water quality as a baseline condition; and detect changes in the quantity and quality of surface and groundwater over time due to the cooling canal system associated with the Uprate Project. The Revised Plan includes installation and monitoring of an appropriate network of wells and surface water stations.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
The first semi-annual report was submitted to FDEP, SFWMD and DERM on February 17, 2011. The first annual report was submitted to FDEP, SFWMD and DERM on August 31, 2011. FPL and the agencies hold regular quarterly meetings regarding the data collected from the CCM Plan.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project expenditures are estimated to be $651,497 or 31.5% higher than previously projected. The variance is primarily due to sampling and analysis work deferred from 2010 to 2011 as a result of increased work scope required by the regulatory agencies for installation of the sampling wells.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
FPL continues to conduct groundwater, surface water and ecological monitoring required by the CCM Plan. FPL continues to conduct groundwater, surface water and ecological monitoring required by the CCM Plan. The first semi-annual report was submitted to FDEP, SFWMD and DERM on February 17, 2011. The first annual report was submitted to FDEP, SFWMD and DERM on August 31, 2011. FPL and the agencies hold regular quarterly meetings regarding the data collected from the CCM Plan. FPL expects that the agencies will approve the Quality Assurance Project Plan by the end on 2011. Monitoring requirements associated with the CCM Plan will continue through 2011.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are $1,320,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: NESHAP Information Collection Request Project (National Emission Standards for Hazardous Air Pollutants) – O & M
Project No. 43

Project Description:
Pursuant to EPA's authority under Section 114 of the Clean Air Act (CAA), the EPA issued an Information Collection Request (ICR) to coal- and oil-fired electric utility steam generating units in January 2010. Four (4) FPL facilities received this information request from the EPA and were thus required by law to conduct extensive stack testing and oil sampling and analysis on eight (8) units in accordance with an EPA approved protocol. Data from the stack testing and analysis and the oil sampling and analysis was required to be quality assured and submitted to the EPA via the EPA Electronic Reporting Tool (ERT). EPA had solicited comments and any additional data which would assist them in writing the draft and final rules.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
All testing and sampling for the eight (8) units is complete. The final data and analysis reports for five (5) units are complete and have been submitted to the EPA. The final reports for two (2) units were submitted to the EPA on August 28, 2010, and the final report for the last unit will be submitted to the EPA in early September, 2010. FPL provided additional information to EPA on the risk assessment of oil-fired unit acid gasses and emissions of Nickel compounds that demonstrated risks below EPA threshold levels. FPL also filed comments with EPA on August 4, 2011 requesting that EPA reduce testing and reporting requirements, allow limited use units to operate without additional controls, and to not regulate acid gases from oil-fired units.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project expenditures re estimated to be $8,385, versus an original estimate of $0. The costs are associated with additional activities needed to support comments on EPA's draft Air Toxics Rule, in order to avoid regulation of specific air toxics in the final rule. FPL is providing comments regarding the justification for not regulating emissions of acid gases, Nickel, and Mercury from oil-fired generating units subject to the Air Toxics rule and will incur additional costs in July and August in its preparation of comments to the draft rule.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
All testing and sampling for the eight (8) units is complete. The final data and analysis reports for five (5) units are complete and have been submitted to the EPA. The final reports for two (2) units was finalized and submitted to the EPA by August 4, 2010. FPL provided additional data and analysis of residual fuel acid gasses and nickel compound emissions. With the close of the comment period on August 4, 2011, FPL does not anticipate any further activities for this project.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are $0.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Martin Plant Barley Barber Swamp Iron Mitigation Project – O & M**
Project No. 44

Project Description:
Martin Plant Barley Barber Swamp Iron Mitigation Project was installed in 2011. The capital project included the installation of complete siphon systems to mitigate iron discharges in the Barley Barber Swamp. The systems will use cooling pond water (low iron) to hydrate the swamp are required by permit.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
Capital installation project completed in May 2011. The project is now operational.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project expenditures are estimated to be $5,000 or 100.0% lower than previously projected. Due to the lack of operating history with the iron mitigation system, costs associated with the operation and maintenance of valves and flow meters will not be incurred in 2011 as originally anticipated. Maintenance of valves and annual calibrations of flow meters will begin in 2012.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
The project completed its first official month of operation in June of 2011. All three siphons are in service from the cooling pond to the Barley Barber Swamp.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are expected to be $2,250.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: 800MW Unit ESP Project – O & M
Project No. 45

Project Description:
On March 16, 2011 the Environmental Protection Agency (EPA) issued a proposed rule that would reduce emissions of toxic air pollutants from power plants. Specifically, the proposed toxics rule would reduce emissions of heavy metals, including mercury (Hg), arsenic, chromium, and nickel, and acid gases, including hydrogen chloride (HCl) and hydrogen fluoride (HF), from new and existing coal- and oil-fired electric utility steam generating units (EGUs). Following the publication of the proposed rule, on June 21, 2011 EPA extended the timeline for public input by 30 days on the proposed rule accepting comments on the proposal until August 4, 2011. The EPA is expected to finalize the air toxic rule by November 16, 2011. To comply, FPL will install Electrostatic precipitators on Manatee Units 1 and 2 and Martin Units 1 and 2.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
There was no activity for 2011.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
There was no activity for 2011.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
There was no activity for 2011.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures for the period January 2012 through December 2012 are expected to be $411,120.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Low NOx Burner Technology – Capital**
Project No. 2

Project Description:
Under Title I of the Clean Air Act Amendments of 1990, Public Law 101-349, utilities with units located in areas designated as "non-attainment" for ozone will be required to reduce NOx emissions by implementing Reasonably Available Control Technology (RACT). The Dade, Broward and Palm Beach county areas were classified as "moderate non-attainment" by the State of Florida and the EPA. FPL has six units in this affected area that require implementation of RACT for NOx emission reductions.

The Florida DEP designated Low NOx Burner Technology (LNBT) as RACT determining that it meets the requirement to reduce NOx emissions. Reductions are achieved by delaying the mixing of the fuel and air at the burner, creating a staged combustion process along the length of the flame. NOx formation is reduced because peak flame temperatures and availability of oxygen for combustion is reduced in the initial stages.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
All six units are in service and operational.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
The variance in the Project depreciation and return is estimated to be $0.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
Dade, Broward and Palm Beach Counties have now been re-designated as "attainment" for ozone with air quality maintenance plans. This re-designation still requires that all controls, such as LNBT, placed in effect during the "non-attainment" be maintained. The LNBT burners are installed at all of the six units and design enhancements are complete.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures (depreciation and return) for the period January 2012 through December 2012 are $307,169.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Continuous Emission Monitoring System (CEMS) – Capital**
Project No. 3b

Project Description:
The Clean Air Act Amendments of 1990, Public Law 101-549, established requirements for the monitoring, record keeping, and reporting of SO2, NOx, CO, Carbon Dioxide (CO2/O2) emissions, as well as opacity data from affected air pollution sources. FPL has 57 units, which are affected and which have installed CEMS to comply with these requirements.

40 CFR Part 75 includes the general requirements for the installation, certification, operation and maintenance of CEMS and specific requirements for the monitoring of pollutants and opacity. These Systems continuously extract and analyze gaseous samples for each power plant stack and have automated data acquisition and reporting capability. Operation and maintenance of these systems in accordance with the provisions of 40 CFR Part 75 is an ongoing activity, which follow the Title IV CEMS Quality Assurance Program Manual.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
This is an ongoing project. No new additions to plants for 2011.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project depreciation and return on investment are estimated to be $367 or 0.1% lower than previously projected.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
No new activity for 2011.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures (depreciation and return) for the period January 2012 through December 2012 are $693,652.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Clean Closure Equivalency – Capital
Project No. 4b

Project Description:
In compliance with 40 CFR 270.1(c)(5) and (6), FPL developed Coeds for nine FPL power plants to demonstrate to the U.S. EPA that no hazardous waste or hazardous constituents remain in the soil or water beneath the basins which had been used in the past to treat corrosive hazardous waste. The basins, which are still operational as part of the wastewater treatment systems at these plants, are no longer used to treat hazardous waste.

To demonstrate clean closure, soil sampling and ground water monitoring plans, implementation schedules, and related reports must be submitted to the EPA. Capital costs are for the installation of monitoring wells (typically four per site) necessary to collect ground water samples for analysis.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
The variance in the Project depreciation and return is estimated to be $0.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
All activities are complete.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures (depreciation and return) for the period January 2012 through December 2012 are $2,012.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Maintenance of Stationary Above Ground Fuel Storage Tanks – Capital**
Project No.5b

Project Description:
Florida Administrative Code (F.A.C.) Chapter 62-761, previously 17-762, which became effective on March 12, 1991, provides standards for the maintenance of stationary above ground fuel storage tank systems. These standards impose various implementation schedules for inspections/repairs and upgrades to fuel storage tanks.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
No Capital Projects for 2011 cycle.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project depreciation and return on investment are estimated to be $21,817 or 2.1% lower than previously projected.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
No Capital Projects for 2011 cycle.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures (depreciation and return) for the period January 2012 through December 2012 are $1,027,134.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Relocate Turbine Lube Oil Underground Piping to Above Ground – Capital**
Project No. 7

Project Description:
In accordance with criteria contained in Chapter 62-762 of the Florida Administrative Code (F.A.C.) for storage of pollutants, FPL initiated the replacement of underground Turbine Lube Oil piping to above ground installations at the St. Lucie Nuclear Power Plant.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
The variance in the Project depreciation and return is estimated to be $0.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
This project is complete.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures (depreciation and return) for the period January 2012 through December 2012 are $1,539.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Oil Spill Cleanup/Response Equipment – Capital**
Project No. 8b

Project Description:
The Oil Pollution Act of 1990 (OPA '90) mandates that all liable parties in the petroleum handling industry file plans by August 18, 1993. In these plans, a liable party must identify (among other items) its spill management team, organization, resources and training. Within this project, FPL developed the plans for ten power plants, five fuel oil terminals, three pipelines, and one corporate plan. Additionally, FPL purchased the mandated response resources and provided for mobilization to a worst case discharge at each site.

Project Accomplishments
(January 1, 2011 to December 31, 2011)
All equipment is being maintained and replaced as necessary to maintain compliance with regulatory guidelines for response readiness. We have purchased one response trailer and are planning to purchase two additional response trailers by the end of the year.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project depreciation and return on investment are estimated to be $11,284 or 8.2% lower than originally projected.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
All deadlines, both state and federal, have been met. Ongoing costs will be annual in nature and will consist of equipment upgrades/replacements. We have purchased one response trailer and are planning to purchase two additional response trailers by the end of the year.

Project Projections
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures (depreciation and return) for the period January 2012 through December 2012 are $141,165.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Relocate Storm Water Runoff – Capital**
Project No. 10

Project Description:
The new National Pollutant Discharge Elimination System (NPDES) permit, Permit No. FL0002206 for the St. Lucie plant, issued by the United States Environmental Protection Agency contains new effluent discharge limitations for industrial-related storm water from the paint and land utilization building areas. The new requirements became effective on January 1, 1994. As a result of these new requirements, the effected areas will be surveyed, graded, excavated and paved as necessary to clean and redirect the storm water runoff. The storm water runoff will be collected and discharged to existing water catch basins on site.

Project Accomplishments:
(January 1, 2011 December 31, 2011)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
The variance in the Project depreciation and return is estimated to be $0.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
All activities are complete.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures (depreciation and return) for the period January 2012 through December 2012 are $8,218.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Scherer Discharge Pipeline- Capital
Project No. 12

Project Description:
On March 16, 1992, pursuant to the provisions of the Georgia Water Control Act, as amended, the Federal Clean Water Act, as amended, and the rules and regulations promulgated there under the Georgia Department of Natural Resources issued the National Pollutant Discharge Elimination System (NPDES) permit for Plant Scherer to Georgia Power Company. In addition to the permit, the department issued Administrative Order EPD-WQ-1855, which provided a schedule for compliance by April 1, 1994 with the new facility discharge limitations to Berry Creek. As a result of these new limitations, and pursuant to the order, Georgia Power Company was required to construct an alternate outfall to redirect certain wastewater discharges to the Ocmulgee River. Pursuant to the ownership agreement with Georgia Power Company for Scherer Unit 4, FPL is required to pay for its share of construction of the discharge pipeline, which will constitute the alternate outfall.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
The variance in the Project depreciation and return is estimated to be $0.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
All activities are complete.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures (depreciation and return) for the period January 2012 through December 2012 are $55,428.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Wastewater Discharge Elimination & Reuse – Capital
Project No. 20

Project Description:
Pursuant to 33 U.S.C. Section 1342 and 40 CFR 122, FPL is required to obtain NPDES permits for each power plant facility. The last permits issued contain requirements to develop and implement a Best Management Practice Pollution Prevention Plan (BMP3 Plan) to minimize or eliminate, whenever feasible, the discharge of regulated pollutants, including fuel oil and ash, to surface waters. In addition, the 1997 Federal Ambient Water Quality Criteria requires FPL to meet surface water standards for any wastewater discharges to groundwater at all plants, and the Dade County DERM requires the Turkey Point and Cutler plants' wastewater discharges into canals to meet county water quality standards found in Section 24-11, Code of Metropolitan Dade County.

In order to address these requirements, FPL has undertaken a multifaceted project which includes activities such as ash basin lining, installation of retention tanks, tank coating, sump construction, installation of pumps, motor, and piping, boiler blowdown recovery, site preparation, separation of stormwater and ashwater systems, separation of potable and service water systems, and the associated engineering and design work to implement these projects.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project depreciation and return on investment are estimated to be $27,928 or 17.2% lower than previously projected. Costs associated with the removal of the Basin Liner at Port Everglades plant were inadvertently included as capital costs when the new Basin Liner was placed in-service in 2010. The removal costs were recorded to the proper removal account in 2011.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
All activities are complete.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures (depreciation and return) for the period January 2012 through December 2012 are $122,512.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: St. Lucie Turtle Net – Capital
Project No. 21

Project Description:
FPL is limited in the number of lethal turtle takings permitted at its St. Lucie Power Plant by the Incidental Take Statement contained in the Endangered Species Act Section 7 Consultation Biological Opinion, issued to FPL on May 4, 2001 by the National Marine Fisheries Service ("NMFS"). The number of lethal takings permitted in a given year is calculated by taking one percent of the total number of loggerhead and green turtles captured in that year. The Incidental Take Statement separately limits the number of lethal takings of Kemp's Ridley turtles to two per year over the next ten years, and the number of lethal takings of either hawksbill or leatherback turtles to one of those species every two years over the next ten years. An effective 5-inch primary barrier net is vital to limiting the number of lethal turtle takes per year. In 2002, the existing net became deformed due to the influxes of jellyfish and algae entering the canal. With the Commission approval, a replacement and enhancement of the net system was performed. In 2007, the antifoulant and protective coating on the existing 5-inch net deteriorated and was experiencing UV damage. With Commission approval, FPL purchased and installed a new 5-inch net in 2009.

In October 2009, the 5-inch primary barrier net failed due to influxes of algae that entered the canal and created a blockage of approximately 80% of the net. The net is currently in a temporary configuration, which has created an effective temporary barrier for turtles. The Turtle Net project now requires the engineering, construction and installation of a more robust barrier structure that can withstand significant algal events and similar environmental challenges. The proposed design would include the removal of the damaged piles and installation of new piles and a support structure to effectively secure the net.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
Engineers have proposed a design for a more effective barrier structure.

Project Fiscal Expenditures:
(January 1, 2011 – December 31, 2011)
Project depreciation and return on investment are estimated to be $6,552 or 5.8% lower than originally projected.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
Engineering vendor to be selected and drawings received by 12/31/11. Site certification approval process to commence. The current net will remain in a temporary configuration until the new structure is constructed. Engineering of the structure will continue through 2011 and into first quarter of 2012.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures (depreciation and return) for the period January 2012 through December 2012 are $117,077.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Pipeline Integrity Management (PIM) – Capital
Project No. 22

Project Description:
FPL is required to develop a written pipeline integrity management program for its hazardous liquid / gas pipelines. This program must include the following elements: (1) a process for identifying which pipeline segments could affect a high consequence area; (2) a baseline assessment plan; (3) an information analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure; (4) the criteria for determining remedial actions to address integrity issues raised by the assessments and information analysis; (5) a continual process of assessment and evaluation of pipeline integrity; (6) the identification of preventive and mitigative measures to protect the high consequence area; (7) the methods to measure the program's effectiveness; (8) a process for review of assessment results and information analysis by a person qualified to evaluate the results and information; and, (9) record keeping.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
A pipeline leak detection system for the TMR-30 Pipeline was engineered and major elements purchased during the 2011 calendar year. Metering skids for Port of Palm Beach and the Martin Terminal have been specified and will be received and placed on foundations by end of 2011. The remainder of mechanical, electrical, controls and commissioning will be conducted in 2012.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project depreciation and return on investment are estimated to be $90 or 1.5% lower than previously projected.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
Leak detection engineering analysis completed and positive displacement meters were found to be the most effective and reliable metering application for this cargo offloading pipeline. The needs of the system to detect and evacuate entrained air are critical design consideration on this leak detection system. We expect to have metering skids received in December and placed on foundations by end of year.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures (depreciation and return) for the period January 2012 through December 2012 are $146,193.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: SPCC (Spill Prevention, Control, and Countermeasures) – Capital
Project No. 23

Project Description:
The EPA first established the SPCC Program in 1973 when the agency issued the Oil Pollution Prevention Regulation (i.e., SPCC rule) to address the oil spill prevention provisions contained in the Federal Water Pollution Control Act of 1972 (later amended as the Clean Water Act). The purpose of the regulation was to prevent discharges of oil from reaching the navigable waters of the U.S. or adjoining shorelines and to prepare facility personnel to respond to oil spills. The SPCC regulation requires certain facilities to prepare and implement SPCC Plans and address oil spill prevention requirements including the establishment of procedures, methods, equipment, and other requirements to prevent discharges of oil as described above. Specifically, the rule applies to any owner or operator of a non-transportation related facility that:

- Has a combined aboveground oil storage capacity of more than 1320 gallons, or a total underground oil storage capacity exceeding 42,000 gallons (Note: the underground storage capacity does not apply to those tanks subject to all of the technical requirements of the federal underground storage tank rule found in 40 CFR 280 or a State approved program); and

- Due to its location, could be reasonably expected to discharge oil in quantities that may be harmful into or upon the navigable waters of the United States or adjoining shorelines.

  In January 1988, a large storage tank owned by Ashland Oil Company at a site in western Pennsylvania collapsed, releasing approximately 750,000 gallons of diesel fuel to the Monongahela River. Following calls for new tank legislation, an EPA task force recommended expanded regulation of aboveground tanks within the framework of existing legislative authority. The result was EPA's SPCC rulemaking package, the first phase of which was proposed in 1991. Due to a series of agency delays primarily resulting from the 1989 Exxon Valdez oil spill that required EPA to issue the Facility Response Plan rule under the Oil Pollution Act of 1990, the final SPCC Rule was not published until July of 2002. A deficiency was found at the St, Lucie Unit 2 Diesel Oil Storage Tank and refueling tank areas. In order to meet compliance regulations, these areas are required to have secondary containment systems installed. For compliance, it is necessary to install oil berms, designed to catch any spilled oil upon delivery, in these areas.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
Implementation of additional secondary containment around PPE Metering Tanks continues. Work will be completed this year. St. Lucie facility upgrades have been completed on three of three identified areas for compliance with SPCC regulations.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project depreciation and return on investment were $43,344 or 2.2% higher than previously projected.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
Implementation of additional secondary containment around PPE Metering Tanks continues. Work will be completed this year. Progress in 2009 includes planning for the two new projects to be implemented in 2010. The current EPA compliance deadline for implementation of the SPCC plans is November 10, 2010. In addition, at St. Lucie installation of the permanent rainwater removal system is complete. Final project closeout to be completed third quarter 2010.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures (depreciation and return) for the period January 2012 through December 2012 are $2,032,074.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Manatee Reburn – Capital
Project No. 24

Project Description:
This project involves installation of reburn technology in Manatee Units 1 and 2. Reburn is an advanced nitrogen oxides (NOx) control technology that has been developed for, and applied successfully in, commercial applications to utility and large industrial boilers. The process is a proven advanced technology, with applications of a reburn-like flue gas incineration technique dating back to the late 1960s, and developments for applications to large coal fired power plants in the United States dating back to the early to mid 1980s.

Reburn is an in-furnace NOx control technology that employs fuel staging in a configuration where a portion of the fuel is injected downstream of the main combustion zone to create a second combustion zone, called the reburning zone. The reburning zone is operated under conditions where NOx from the main combustion zone is converted to elemental nitrogen (which makes up 79% of the atmosphere). The basic front wall-fired boiler reburning process is shown conceptually in Figure 1 (see below), and divides the furnace into three zones.

In the 1996-97 time period, FPL invested a considerable effort evaluating the Manatee Units for the application of reburn technology. FPL has recently reviewed the reburn system designs previously proposed for the Manatee units, and concluded that a design for either oil or gas reburn would require very similar characteristics. This will require reburn fuel injectors to be located at the elevation of the present top row of burners, with reburn injectors on the boiler front and rear walls. For the present application the injectors will be required to have a dual fuel (oil and gas) capability. In order to provide adequate residence time for the reburn process, it is proposed to locate the reburn overfire air (OFA) ports between the boiler wing walls and to angle them slightly to provide better mixing with the boiler flow. Because of the complexity of the boiler flow field and the port location, it was determined that OFA booster fans would be required to assist the air-fuel mixing and complete the burnout process. Installation of reburn technology for Manatee Units 1 and 2 offers the potential to reduce NOx emissions through a "pollution prevention" approach that does not require the use of reagents, catalysts, and pollution reduction or removal equipment. FDEP and FPL agree that reburn technology is the most cost-effective alternative to achieve significant reductions in NOx emissions from Manatee Units 1 and 2.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
Installation of the Unit 1 and Unit 2 equipment is complete, started up and completed process optimization of the new systems to ensure minimal emissions. Both units are out of warranty. New permit limits have been accepted by the FDEP. Continuing to incur on-going operating and maintenance costs.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project depreciation and return on investment are estimated to be $14,270 or 0.4% lower than previously projected.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
Unit 1 and 2 both completed.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures (depreciation and return) for the period January 2012 through December 2012 are $3,291,987.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Pt. Everglades ESP (Electrostatic Percipitators) Technology – Capital**
Project No. 25

Project Description:
The requirements of the Clean Air Act direct the Environmental Protection Agency to develop health-based standards for certain "criteria pollutants". i.e. ozone (O3), sulfur dioxide (SO2), carbon monoxide (CO), particulate matter (PM), nitrogen oxides (NOx), an lead (Pb). EPA developed standards for the criteria pollutants and regulates the emissions of those pollutants from major sources by way of the Title V permit program. Florida has been granted authority from the EPA to administer its own Title V program which is at least as stringent as the EPA requirements. Florida is able to issue, renew and enforce Title V air operating permits for sources within the state via 403.061 Florida Statutes and Chapter 62-213 F.A.C., which is administered by the State of Florida Department of Environmental Protection ("DEP"). The Title V program addresses the six criteria pollutants mentioned earlier, and includes hazardous air pollutants (HAP). The EPA sets the limits of emissions of Hazardous Air Pollutants through the Maximum Achievable Control Technology (MACT). The original Port Everglades Title V permit, issued in 1998, expired in 2003. The renewal permit issued January 1, 2004 is now expiring December 31, 2008. A renewal permit application has been submitted and is pending DEP review. The DEP's Title V permit for FPL Port Everglades plant requires FPL to install and maintain Electrostatic Precipitators at all four Port Everglades units to address local concerns and to insure compliance with the National Ambient Air Quality Stands and the EPA MACT Standards.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
No Power Generation plant additions occurred.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
The variance in the Project depreciation and return is estimated to be $0.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
At this time, all four ESPs (Units 1 through 4) have construction activities completed and are operational. The Units 1-4 precipitators met all performance guarantees and permit requirements. The Units 1-4 stack emissions were well below the new Title V permit requirements of .03 lb/mmbtu particulate and 20% opacity. Enclosure of ash truck loading bay is completed to contain fugitive airborne ash during truck loadings.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures (depreciation and return) for the period January 2012 through December 2012 are $8,055,204.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **UST Replacement/Removal – Capital**
Project No. 26

Project Description:
The Florida Administrative Code (FAC) Chapter 62-761.500, dated July 13, 1998, requires the removal or replacement of existing Category-A and Category-B storage tank systems with systems meeting the standards of Category-C storage tank systems by December 31, 2009. UST Category-A tanks are single-walled tanks or underground single-walled piping with no secondary containment that was installed before June 30, 1992.

UST Category-B tanks are tanks containing pollutants after June 30, 1992 or a hazardous substance after January 1, 1994 that shall have a secondary containment. Small diameter piping that comes in contact with the soil that is connected to a UST shall have secondary containment if installed after December 10, 1990.

UST and AST Category-C tanks under F.A.C. 62-761.500 are tanks that shall have some or all of the following; a double wall, be made of fiberglass, have exterior coatings that protect the tank from external corrosion, secondary containment (e.g., concrete walls and floor) for the tank and the piping, and overfill protection.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
There were no activities in 2011.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project depreciation and return on investment are estimated to be $20,646 or 38.7% lower than previously projected. The variance is primarily due to a retirement processed in April 2011 for the underground storage tanks located at FPL's General Office Building. These tanks, with a plant in service balance of $377,470 were included in the sale of FPL's General Office Building, but were not included in the original 2011 projections. An offset to the reserve for the sale proceeds of $345,901 will be made in July 2011's business which will bring the reserve balance to zero.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
Initial review of the scope of work has been completed.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures (depreciation and return) for the period January 2012 through December 2012 are $12,154.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **CAIR Compliance – Capital**
Project No. 31

Project Description:
In response to the EPA Clean Air Interstate Rule (CAIR), FPL initiated the CAIR Project to implement strategies to comply with Annual and Ozone Season NOx and SO2 emissions requirements. The CAIR project to date has included the Black & Veatch (B&V) study of FPL's control and allowance management options, an engineering study conducted by Aptech for the reliable cycling of the 800 MW units, the costs for the operation of SCR's constructed on SJRPP Units 1 and 2, costs for the operation of the Scrubber and SCR being installed on Scherer Unit 4, and the installation of CEMS for the peaking gas turbine units. The 800 MW Cycling Project was added to CAIR after 2006 submittal. Aptech Engineering provided engineering services for the first phase of a multiphase scope of work that will assure that the operating reliability is maintained in a cycling mode. The study costs to Aptech Engineering have been paid and a significant portion of the work has been completed on the Martin and Manatee 800 MW units. Several countermeasures that were prioritized and scheduled for implementation in 2008 – 2011. The CEMS installation on the Gas Turbine Peaking Units has been completed with ongoing maintenance expenses for their operation. On December 3, 2008 Georgia EPD promulgated the GA Multi-Pollutant rule requiring installation of SCR and a Scrubber on Scherer Unit 4. Recently, on July 6, 2010, EPA proposed the Transport Rule, which will leave requirements to comply with the CAIR regulations in place until 2012 when a new program will be implemented to further reduce So2 and NOx emissions from fossil power plants.

Project Accomplishments:
(January. 1, 2011 to December 31, 2011)
800MW Cycling - Completed the implementation of the major 800MW cycling countermeasures for Manatee Unit 1 and Martin Unit 2 during the first half of 2010. Construction efforts remain in progress to complete the remaining Superheat Spray, Extraction and Turbine.

SJRPP 1&2 SCR's are now in operation and construction continues on the Scherer FGD and SCR with an estimated completion in the first half of 2012.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project depreciation and return on investment are estimated to be $1,473,230 or 3.1% lower than previously projected. The variance is primarily due to lower than projected construction costs for SCR and Flue Gas Desulfurization (FGD) systems as a result of contractor efficiencies and reduced contingencies. This variance is partially offset by a change to the in-service date from 2010 to 2011 for the installation of the Boiler and Main Steam Drain project at the Manatee and Martin plants as a result of logic problems with the control system and system load demand. These issues had to be addressed prior to placing the systems in-service.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
Completed the implementation of the major 800MW cycling countermeasures for Manatee Unit 1 and Martin Unit 2 during the first half of 2010. Construction efforts remain in progress to complete the remaining Superheat Spray, Extraction and Turbine Water Induction Prevention countermeasures for Martin Unit 1 by the end of the year. Completion of the Superheat Spray and Extraction countermeasures at Manatee Unit 2 along with Rotor Stress are scheduled for 2011.

FPL's CAIR project at SJRPP U1 & 2 continues with both SCRs in operation. Installation of Scrubbers and SCR's at plant Scherer for compliance with CAIR started in 2011 as common plant facilities were placed in service. Installation of the SCR and Scrubber on Scherer Unit 4 is underway and construction is scheduled for completion in early 2012.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures (depreciation and return) for the period January 2012 through December 2012 are $58,932,516.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: CAMR Compliance – Capital
Project No. 33

Project Description:
The Clean Air Mercury Rule (CAMR) was promulgated by the Environmental Protection Agency (EPA) on March 15, 2005, imposing nation-wide standards of performance for mercury (Hg) emissions from existing and new coal-fired electric utility steam generating units. The CAMR is designed to reduce emissions of Hg through implementation of coal-fired generating unit Hg controls. In addition, CAMR requires the installation of Hg Continuous Emission Monitoring Systems (HgCEMS) to monitor compliance with the emission requirements. The rule is implemented in two phases with an initial compliance date of 2010 for Phase I and the final required reductions of Phase II in 2018. The State of Florida has begun the implementation of the requirements for reduction of Hg through rule making process. Plant St. John's River Power Park (SJRPP) Units 1 & 2, in which FPL has 20% ownership shares, are affected units under this rule and will require the installation of Hg controls and HgCEMS. Similarly, the State of Georgia has also begun their rule making process to implement the federal rule, which will affect FPL's ownership share of Plant Scherer Unit 4, also requiring the installation of HgCEMS and Hg controls.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
The Scherer Unit 4 baghouse was placed into service April 4, 2010 meeting the GA Multi-Pollutant Rule requirements. The baghouse passed all performance guarantee tests in May 2010 and is now in continuous operation.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project depreciation and return are estimated to be $152,209 or 1.2% lower than previously projected.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
The Scherer Unit 4 baghouse was placed into service April 4, 2010. The baghouse passed all performance guarantee tests in May 2010.

Project Projections:
(January 1, 2012 - December 31, 2012)
Estimated project fiscal expenditures (depreciation and return) for the period January 2012 through December 2012 are $12,514,950.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **St. Lucie Cooling Water System Inspection and Maintenance – Capital**
Project No. 34

Project Description:
The purpose of the proposed St. Lucie Plant Cooling Water System Inspection and Maintenance Project (the "Project") is to inspect and, as necessary, maintain the cooling water system (the "Cooling System") at FPL's St. Lucie nuclear plant , such that it minimizes injuries and/or deaths of endangered species and thus helps FPL to remain in compliance with the federal Endangered Species Act, 16 U.S.C. Section 1531, et seq. (the "ESA") The St. Lucie Plant is an electric generating station on Hutchinson Island in St. Lucie County, Florida. The plant consists of two nuclear-fueled 850 net MWe units, both of which use the Atlantic Ocean as a source of water for once-through condenser cooling. This cooling water is supplied to the units via the Cooling System. The St. Lucie Plant cannot operate without the Cooling System. Compliance with the ESA is a condition to the operation of the St. Lucie Plant. Inspection and cleaning of the intake pipes is an "environmental compliance cost" under section 366.8255, Florida Statutes. The specific "environmental law or regulation" requiring inspection and cleaning of the intake pipes are terms and conditions that will be imposed pursuant to a Biological Opinion ("BO") that is to be issued by the National Oceanic and Atmospheric Administration ("NOAA") pursuant to section 7 of the ESA. It is anticipated that NOAA will finalize the BO in late 2011 or early 2012. NOAA sent the Nuclear Regulatory Commission ("NRC") a letter dated December 19, 2006, confirming its intent to issue the BO and stating the requirements that will be imposed pursuant to the BO with respect to inspection and cleaning of the intake pipes.

Project Accomplishments:
(January 1, 2011 thru December 31, 2011)
Preliminary turtle excluder design documents (drawings and calculations) were completed in the spring of 2010. No work on the turtle excluder design package and testing was performed in 2011.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project depreciation and return on investment are estimated to be $139,324 or 100.0% lower than previously projected. The variance is primarily due to a change in the projected in-service date for the Turtle Excluders from September 2011 to September 2013 as a result of a delay in the issuance of the Biological Opinion.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
The turtle excluder design package documents (drawings and calculations) were started in the spring of 2009. Preliminary design documents were completed in spring of 2010. Flow meters to be installed in 2011. Final documents and testing anticipated to be completed in 2012.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures (depreciation and return) for January 2012 through December 2012 are $0.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Martin Plant Drinking Water System Compliance – Capital**
Project No. 35

Project Description:
The Martin Drinking Water System (DWS) is required to comply with the requirements the Florida Department of Environmental regulations rules for drinking water systems. The Florida Department of Environmental Protection (FDEP) determined the system must be brought into compliance with newly imposed drinking water rules for TTHM (trihalomethanes) and HAA5 (Haleo Acetic Acid). The upgrades to the potable water system will cause FPL to incur capital costs for major component upgrades to the system in order to comply with the new requirements. These include Nano filtration, air stripping, carbon and multimedia filtration. The operation of the potable system will cause FPL to incur O&M costs for certain products that are consumed during the water treatment process. These include carbon and multimedia bed media and nano filtration media.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
The system is in service in 2008 and operating as designed.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Depreciation and return are estimated to be $1,309 or 4.9% higher than projected.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
The installation was approved by FDEP, the capital installation was completed in 2008 and the system is in service.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures (depreciation and return) for the period January 2012 through December 2012 are $25,997.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Low Level Radioactive Waste - Capital**
Project No. 36

Project Description:
The Barnwell, South Carolina radioactive waste disposal facility is the only site of its kind presently available to FPL for disposal of Low Level Waste (LLW) such as radioactive spent resins, filters, activated metals, and other highly contaminated materials. The Barnwell facility ceased accepting LLW from FPL June 30th, 2008. This project will construct a LLW storage facility for class B and C radioactive waste at the St. Lucie Plant (PSL). Turkey Point (PTN) will be implementing a similar project; however the PTN project will start later than the PSL project since PTN has some limited existing LLW storage capacity. Where practical, this project will be implemented as part of a fleet approach. The objective at PSL and PTN is to ensure construction of a LLW storage facility with sufficient capacity to store all LLW B and C class waste generated at each plant site over a 5 year period. This will allow continued uninterrupted operation of the PSL and PTN nuclear units until an alternate solution becomes available. The LLW on site storage facilities at PSL and PTN will also provide a "buffer" storage capacity for LLW even if an alternate solution becomes feasible, should the alternate solution be delayed or interrupted at a later date.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
The Turkey Point Level 1 project schedule has been created. The engineering vendor is currently conducting soil testing and preliminary engineering work is progressing with a 90% package delivery scheduled in late August 2011. Construction is expected to begin in October 2011 and the building should be completed by March 2012.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project depreciation and return on investment are estimated to be $132,076 or 22.1% lower than previously projected. The variance is primarily due to a change in the projected in-service dates for the St. Lucie and Turkey Point Nuclear Plants due to the relocation of the Waste Storage facility at Turkey Point and limited resources to work on both projects. The St. Lucie projected in-service date was changed from December 2010 to July 2011 and the Turkey Point projected in-service date was changed from October 2011 to March 2012.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
The LLW Project at St. Lucie has experienced some additional schedule delays due to the competition for resources caused by the extended St. Lucie Unit 1 Cycle 23 refueling outage. This has resulted in delaying the completion of the facility from 3rd quarter 2010 to August 2011.

The St. Lucie LLW schedule delay has shifted some of the projected 2010 expenditures for the construction work into 2011. The Turkey Point LLW project is expecting completion in March 2012. Turkey Point LLW is behind schedule due to delays experienced at St. Lucie LLW competing for common resources.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures (depreciation and return) for January 2012 through December 2012 are $1,305,096.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: DeSoto Next Generation Solar Energy Center – Capital
Project No. 37

Project Description:
The DeSoto Next Generation Solar Energy Center ("DeSoto Solar") project is a zero greenhouse gas emitting renewable generation project which on August 4, 2008, the Commission found in Order Number PSC-08-0491-PAA-EI, to be eligible for recovery through the ECRC pursuant to House Bill 7135. The DeSoto Solar project is a 25 MW solar photovoltaic generating facility which will convert sunlight directly into electric power. The facility will utilize a tracking array that is designed to follow the sun as it traverses through the sky. In addition to the tracking array this facility will utilize cutting edge solar panel technology. The project will involve the installation of the solar PV panels and tracking system and electrical equipment necessary to convert the power from direct current to alternating current and to connect the system to the FPL grid.

Project Accomplishments:
(January 1, 2010 to December 31, 2011)
Desoto Next Generation Solar Energy Center achieved Commercial Operation on October 27, 2009. All Engineering and Construction "punch list" items have been completed and Final Acceptance was achieved on April 27, 2010.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project depreciation and return were $52,406 or 0.3% lower than previously projected.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
Desoto achieved Commercial Operation on October 27, 2009 and Final Acceptance on April 27, 2010.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures (depreciation and return) for January 2012 through December 2012 are expected to be $17,511,856.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **Space Coast Next Generation Solar Energy Center – Capital**
Project No. 38

Project Description:
The Space Coast Next Generation Solar Energy Center ("Space Coast Solar") project is a zero greenhouse gas emitting renewable generation project, which on August 4, 2008, the Commission found in Order Number PSC-08-0491-PAA-EI, to be eligible for recovery through the ECRC pursuant to House Bill 7135. The Space Coast Solar project is a 10 MW solar photovoltaic (PV) generating facility which will convert sunlight directly into electric power. The facility will utilize a fixed PV array oriented to capture the maximum amount of electricity from the sun over the entire year. The project will involve the installation of the solar PV panels and support structures and electrical equipment necessary to convert the power from direct current to alternating current and to connect the system to the FPL grid.

The Space Coast project also includes building a 900 KW solar PV facility at the Kennedy Space Center (KSC) industrial area. This 900 KW solar site will be built and operated and maintained by FPL as compensation for the lease of the land for the Space Coast Solar Site which is located on KSC property.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
Space Coast Solar Site achieved commercial operation on April 16, 2010. Completion of all Engineering and Construction "punch list" items and Final Acceptance occurred on October 13, 2010.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project depreciation and return were $33,752 or 0.4% lower than previously projected.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
Space Coast Solar Site achieved commercial operation on April 16, 2010 and Final Acceptance is expected by September 30, 2010.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures (depreciation and return) for January 2012 through December 2012 are $8,246,105.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Martin Next Generation Solar Energy Center – Capital
Project No. 39

Project Description:
The Martin Next Generation Solar Energy Center ("Martin Solar") project is a zero greenhouse gas emitting renewable generation project which on August 4, 2008, the Commission found in Order Number PSC-08-0491-PAA-EI, to be eligible for recovery through the ECRC pursuant to House Bill 7135. The Martin Solar project is a 75 MW solar thermal steam generating facility which will be integrated into the existing steam cycle for the Martin Unit 8 natural gas-fired combined cycle power plant. The steam to be supplied by Martin Solar will be used to supplement the steam currently generated by the heat recovery steam generators. The project will involve the installation of parabolic trough solar collectors that concentrate solar radiation. The collectors will track the sun to maintain the optimum angle to collect solar radiation. The collectors will concentrate the sun's energy on heat collection elements located in the focal line of the parabolic reflectors. These heat collection elements contain a heat transfer fluid which is heated by the concentrated solar radiation to approximately 750 degrees Fahrenheit. The heat transfer fluid is then circulated to heat exchangers that will produce up to 75 MW of steam that will be routed to the existing natural gas-fired combined cycle Unit 8 heat recovery steam generators.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
Commercial Operation of Martin Solar occurred on December 10, 2010.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project depreciation and return were $197,340 or 0.4% lower than previously projected.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
Commercial Operation of Martin Solar occurred on December 10, 2010.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures (depreciation and return) for January 2012 through December 2012 are expected to be $47,607,281.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Manatee Temporary Heating System Project – Capital
Project No. 41

Project Description:
FPL is subject to specific and continuing legal requirements to provide a warm water refuge for endangered manatees at its Riviera (PRV) and Cape Canaveral Plants (PCC). FPL has undertaken the design, engineering, purchase, and installation of a temporary manatee heating system at both PRV and PCC ("the Project"). The Project is required pursuant to PRV's and PCC's Manatee Protection Plans (MPP), as part of the State Industrial Wastewater Facility Permit Numbers FL0001546, Specific Condition 13, issued on February 16, 1998 and FL0001473, Specific Condition 9, issued on August 10,2005, respectively. In order to comply with the respective MPP's, FPL's installation of a temporary manatee heating system at PRV and PCC will be implemented to avoid potential adverse impacts to manatees congregating at PRV's and PCC's manatee embayment area. Manatees currently gather at the plants during the annual period from November 15 to March 31 at PRV and the annual period of October 15 to March 31 at PCC. FPL's installation of the Manatee Temporary Heating System at each site must be implemented to provide warm water until the site has completed the planned modernization of the existing power generation units and return of warm water flow from the generating unit cooling water will be provided by operation of the new units.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
The Manatee Temporary Heating System at PRV began operations in Q4 2009 and was available throughout the 09/10 and 10/11 manatee season. The PCC Manatee Heating System work was completed in September 2010, the unit was available throughout the 2010/2011 manatee season.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project depreciation and return on investment are estimated to be $168,681 or 24.6% higher than previously projected. During the operation of the Cape Canaveral manatee heating system during the first heating season, from October 2010 through March 2011, the need for permanent modifications were identified to increase or maintain heat fed to the Interim Warm Water Refuge Area. These design modifications were specifically targeted to increase the efficiency of delivering and maintaining heated water in the manatee refuge area. The modifications include installing a sheet pile wall to provide a thermal and physical partition, installing a 4-inch natural gas pipe line, a concrete pad, an electrical power panel, and High Density Poly Ethylene (HDPE) piping changes to support the installation of the supplemental heating unit. All these modifications are targeted to be installed and tested prior to the beginning of the October 2011 thru March 2012 season.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
We have a capital modification project underway on the Manatee heating system. It will be completed by Nov/Dec of 2011.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures (depreciation and return) for January 2012 through December 2012 are expected to be $941,820.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Turkey Point Cooling Canal Monitoring Plan – Capital
Project No. 42

Project Description:
Pursuant to Conditions IX and X of the Florida Department of Environmental Protection's (FDEP) Final Order Approving Site Certification, filed October 29, 2008, FPL submitted its initial draft of the proposed Cooling Canal Monitoring Plan associated with FPL's Turkey Point Uprate Project to the South Florida Water Management District (SFWMD). This plan requires an assessment of baseline conditions to provide information on the vertical and horizontal extent of the hypersaline groundwater plume and effect of that plume on ground and surface water quality, if any. Comments, concerns and requests for revisions or action items were received from the SFWMD as well as the FDEP. Miami-Dade Department of Environmental Resource Management (DERM) has incorporated into the current draft the proposed monitoring plan, dated July 16, 2009.

The TP CCM Plan was finalized by FPL and the agencies on October 14, 2009. The objective of FPL's TP CCM Plan is to implement the Conditions of Certification IX and X, which states that "the Revised Plan shall be designed to be in concurrence with other existing and ongoing monitoring efforts in the area and shall include but not necessarily be limited to surface water, groundwater and water quality monitoring, and ecological monitoring to: delineate the vertical and horizontal extent of the hyper-saline plume that originates from the cooling canal system and to characterize the water quality including salinity and temperature impacts of this plume for the baseline condition; determine the extent and effect of the groundwater plume on surface water quality as a baseline condition; and detect changes in the quantity and quality of surface and groundwater over time due to the cooling canal system associated with the Uprate Project. The Revised Plan includes installation and monitoring of an appropriate network of wells and surface water stations.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
The wells and monitoring equipment were installed in 2010 for the Cooling Canals at Turkey Point plant, which included probes, telemetry, solar panels and associated platforms to support the monitoring equipment.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project depreciation and return were $31,306 or 7.1% lower than previously projected.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
Drilling, construction of wells and equipment installation was completed in 2010.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures (depreciation and return) for January 2012 through December 2012 are expected to be $398,925.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Martin Plant Barley Barber Swamp Iron Mitigation Project – Capital
Project No. 44

Project Description:
Engineer and install a siphon and a new discharge system to turn the existing flow away from the Barley Barber Swamp and back into the Martin Plant Cooling Pond.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
A new siphon and discharge system was engineered and installed. The system has been placed into service.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Project depreciation and return on investment are estimated to be $15,001 or 65.2% lower than previously projected. The variance is primarily due to lower than anticipated vendor bids for engineering work.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
The project installation was engineered and installed. The capital project is in service.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures (depreciation and return) for January 2012 through December 2012 are expected to be $16,960.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: **800MW Unit ESP Project – Capital**
Project No. 45

Project Description:
On March 16, 2011 the Environmental Protection Agency (EPA) issued a proposed rule that would reduce emissions of toxic air pollutants from power plants. Specifically, the proposed toxics rule would reduce emissions of heavy metals, including mercury (Hg), arsenic, chromium, and nickel, and acid gases, including hydrogen chloride (HCl) and hydrogen fluoride (HF), from new and existing coal- and oil-fired electric utility steam generating units (EGUs). Following the publication of the proposed rule, on June 21, 2011 EPA extended the timeline for public input by 30 days on the proposed rule accepting comments on the proposal until August 4, 2011. The EPA is expected to finalize the air toxic rule by November 16, 2011. To comply, FPL will install Electrostatic precipitators on Manatee Units 1 and 2 and Martin Units 1 and 2.

Project Accomplishments:
(January 1, 2011 to December 31, 2011)
Contract was executed in May 2011 for the fabrication and installation of the ESP's.

Project Fiscal Expenditures:
(January 1, 2011 to December 31, 2011)
Costs to date are booked to base capital under PSC-11-0083-FOF-EI and will be transferred to ECRC once the EPA issues the final rule in November 2011.

Project Progress Summary:
(January 1, 2011 to December 31, 2011)
Contract was executed in May 2011 for the fabrication and installation of the ESP's. Work on the first unit, Manatee Unit 2 is scheduled to commence in October 2011.

Project Projections:
(January 1, 2012 to December 31, 2012)
Estimated project fiscal expenditures (depreciation and return) for January 2012 through December 2012 are expected to be $7,072,368.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Energy & Demand Allocation % By Rate Class
January 2012 to December 2012

Rate Class	(1) Avg 12 CP Load Factor at Meter (%)	(2) GCP Load Factor at Meter (%)	(3) Projected Sales at Meter (KWH)	(4) Projected Avg 12 CP at Meter (KW)	(5) Projected GCP at Meter (KW)	(6) Demand Loss Expansion Factor	(7) Energy Loss Expansion Factor	(8) Projected Sales at Generation (KWH)	(9) Projected Avg 12 CP at Generation (kW)	(10) Projected GCP Demand at Generation (kW)	(11) Percentage of KWH Sales at Generation (%)	(12) Percentage of 12 CP Demand at Generation (%)	(13) Percentage of GCP Demand at Generation (%)
RS1/RST1	57.599%	54.652%	55,179,030,324	10,935,983	11,525,701	1.08810438	1.06731780	58,893,561,010	11,899,491	12,541,166	53.93428%	62.42542%	59.12277%
GS1/GST1/WIES1	75.719%	62.619%	5,436,225,128	819,574	991,033	1.08810438	1.06731780	5,802,179,820	891,782	1,078,347	5.31359%	4.67834%	5.08365%
GSD1/GSDT1/HLFT1 (21-499 kW)	78.538%	67.895%	23,806,124,732	3,460,218	4,002,627	1.08796333	1.06721579	25,406,272,158	3,764,590	4,354,711	23.26687%	19.74926%	20.52940%
OS2	157.921%	15.242%	12,458,252	901	9,331	1.03932081	1.03077721	12,841,683	936	9,698	0.01176%	0.00491%	0.04572%
GSLD1/GSLDT1/CS1/CST1/HLFT2 (500-1,999 kW)	77.959%	64.506%	10,401,423,229	1,523,070	1,840,729	1.08626566	1.06601100	11,088,031,586	1,654,459	1,999,521	10.15434%	8.67939%	9.42633%
GSLD2/GSLDT2/CS2/CST2/HLFT3 (2,000+ kW)	93.936%	77.294%	2,211,649,384	268,768	326,636	1.07231098	1.05537171	2,334,112,199	288,203	350,255	2.13756%	1.51193%	1.65121%
GSLD3/GSLDT3/CS3/CST3	92.800%	69.819%	218,123,888	26,832	35,664	1.02560889	1.02041606	222,577,119	27,519	36,577	0.20383%	0.14437%	0.17243%
ISST1D	137.851%	47.288%	0	0	0	1.03932081	1.03077721	0	0	0	0.00000%	0.00000%	0.00000%
ISST1T	62.784%	28.724%	0	0	0	1.02560889	1.02041606	0	0	0	0.00000%	0.00000%	0.00000%
SST1T	62.784%	28.724%	100,498,031	18,273	39,940	1.02560889	1.02041606	102,549,805	18,741	40,963	0.09391%	0.09832%	0.19311%
SST1D1/SST1D2/SST1D3	137.851%	47.288%	7,272,632	602	1,756	1.03932081	1.03077721	7,496,463	626	1,825	0.00687%	0.00328%	0.00860%
CILC D/CILC G	106.252%	83.775%	3,006,093,828	322,970	409,625	1.07110052	1.05486763	3,171,031,077	345,933	438,750	2.90401%	1.81478%	2.06840%
CILC T	107.337%	84.460%	1,332,228,131	141,686	180,062	1.02560889	1.02041606	1,359,426,980	145,314	184,673	1.24495%	0.76233%	0.87060%
MET	72.014%	58.836%	79,693,587	12,633	15,462	1.03932081	1.03077721	82,146,333	13,130	16,070	0.07523%	0.06888%	0.07576%
OL1/SL1/PL1	4996.200%	48.918%	589,146,032	1,346	137,482	1.08810438	1.06731780	628,806,045	1,465	149,595	0.57586%	0.00769%	0.70524%
SL2, GSCU1	100.342%	98.541%	78,713,822	8,955	9,119	1.08810438	1.06731780	84,012,662	9,744	9,922	0.07694%	0.05112%	0.04678%
TOTAL			102,458,681,000	17,541,811	19,525,167			109,195,044,940	19,061,933	21,212,073	100.00%	100.00%	100.00%

Notes:
(1) AVG 12 CP load factor based on 2010 load research data.
(2) GCP load factor based on 2010 load research data.
(3) Projected KWH sales for the period January 2012 through December 2012.
(4) Calculated: (Col 3)/(8,760 * Col 1)
(5) Calculated: (Col 3)/8,760 * Col 2)
(6) Based on 2010 demand losses.
(7) Based on 2010 energy losses.
(8) Col 3 * Col 7
(9) Col 1 * Col 6
(10) Col 2 * Col 6
(11) Col 8 / total for Col 8
(12) Col 9 / total for Col 9
(13) Col 10 / total for Col 10

Totals may not add due to rounding.

Form 42-7P

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of Environmental Cost Recovery Clause Factors
January 2012 to December 2012

Rate Class	(1) Percentage of KWH Sales at Generation (%)	(2) Percentage of 12 CP Demand at Generation (%)	(3) Percentage of GCP Demand at Generation (%)	(4) Energy Related Cost ($)	(5) CP Demand Related Cost ($)	(6) GCP Demand Related Cost ($)	(7) Total Environmental Costs ($)	(8) Projected Sales at Meter (KWH)	(9) Environmental Cost Recovery Factor ($/KWH)
RS1/RST1	53.93428%	62.42542%	59.12277%	$18,924,454	$90,264,681	$1,400,976	$110,590,111	55,179,030,324	0.00200
GS1/GST1	5.31359%	4.67834%	5.08365%	$1,864,433	$6,764,694	$120,462	$8,749,589	5,436,225,128	0.00161
GSD1/GSDT1/HLTF(21-499 kW)	23.26687%	19.74926%	20.52940%	$8,163,878	$28,556,643	$486,466	$37,206,987	23,806,124,732	0.00156
OS2	0.01176%	0.00491%	0.04572%	$4,126	$7,100	$1,083	$12,309	12,458,252	0.00099
GSLD1/GSLDT1/CS1/CST1/HLTF(500-1,999 kW)	10.15434%	8.67939%	9.42633%	$3,562,952	$12,550,051	$223,367	$16,336,370	10,401,423,229	0.00157
GSLD2/GSLDT2/CS2/CST2/HLTF(2,000+ kW)	2.13756%	1.51193%	1.65121%	$750,028	$2,186,190	$39,127	$2,975,345	2,211,649,384	0.00135
GSLD3/GSLDT3/CS3/CST3	0.20383%	0.14437%	0.17243%	$71,521	$208,748	$4,086	$284,355	218,123,888	0.00130
ISST1D	0.00000%	0.00000%	0.00000%	$0	$0	$0	$0	0	0.00101
ISST1T	0.00000%	0.00000%	0.00000%	$0	$0	$0	$0	0	0.00179
SST1T	0.09391%	0.09832%	0.19311%	$32,953	$142,162	$4,576	$179,691	100,498,031	0.00179
SST1D1/SST1D2/SST1D3	0.00687%	0.00328%	0.00860%	$2,409	$4,749	$204	$7,362	7,272,632	0.00101
CILC D/CILC G	2.90401%	1.81478%	2.06840%	$1,018,957	$2,624,107	$49,013	$3,692,077	3,006,093,828	0.00123
CILC T	1.24495%	0.76233%	0.87060%	$436,829	$1,102,293	$20,630	$1,559,752	1,332,228,131	0.00117
MET	0.07523%	0.06888%	0.07576%	$26,396	$99,599	$1,795	$127,790	79,693,587	0.00160
OL1/SL1/PL1	0.57586%	0.00769%	0.70524%	$202,056	$11,113	$16,711	$229,880	589,146,032	0.00039
SL2, GSCU1	0.07694%	0.05112%	0.04678%	$26,996	$73,914	$1,108	$102,018	78,713,822	0.00130
TOTAL				$35,087,989	$144,596,043	$2,369,605	$182,053,636	102,458,681,000	0.00178

Note: There are currently no customers taking service on Schedules ISST1(D) or ISST1(T). Should any customer begin taking service on these schedules during the period, they will be billed using the applicable SST1 Factor.

(1) From Form 42-6P, Col 11

(2) From Form 42-6P, Col 12

(3) From Form 42-6P, Col 13
(4) Total Energy $ from Form 42-1P, Line 5b x Col 1
(5) Total CP Demand $ from Form 42-1P, Line 5b x Col
(6) Total GCP Demand $ from Form 42-1P, Line 5b x
(7) Col 4 + Col 5 + Col 6
(8) Projected KWH sales for the period January 2012 through December 2012.
(9) Col 7 / Col 8 x 100

Totals may not add due to rounding.

FLORIDA POWER LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE

Equity @ 10.00%

CAPITAL STRUCTURE AND COST RATES PER 2009 RATE CASE (a)
Docket No 080677-EI Order No PSC-10-0153-FOF-EI

	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG TERM DEBT	5,298,960,654	31.565%	5.49%	1.73%	1.73%
SHORT TERM DEBT	156,113,805	0.930%	2.11%	0.02%	0.02%
PREFERRED STOCK	0	0.000%	0.00%	0.00%	0.00%
CUSTOMER DEPOSITS	544,711,775	3.245%	5.98%	0.19%	0.19%
COMMON EQUITY	7,889,967,199	46.999%	10.00%	4.70%	7.65%
DEFERRED INCOME TAX	2,892,247,084	17.229%	0.00%	0.00%	0.00%
INVESTMENT TAX CREDITS					
ZERO COST	0	0.000%	0.00%	0.00%	0.00%
WEIGHTED COST	5,429,401	0.032%	8.19%	0.00%	
			0		
TOTAL	$16,787,429,918	100.00%		6.65%	9.60%

CALCULATION OF THE WEIGHTED COST FOR CONVERTIBLE INVESTMENT TAX CREDITS (C-ITC) (b)

	ADJUSTED RETAIL	RATIO	COST RATE	WEIGHTED COST	PRE TAX COST
LONG TERM DEBT	$5,298,960,654	40.18%	5.49%	2.21%	2.21%
PREFERRED STOCK	0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	7,889,967,199	59.82%	10.00%	5.98%	9.74%
TOTAL	$13,188,927,853	100.00%		8.19%	11.94%
RATIO					

DEBT COMPONENTS:	
LONG TERM DEBT	1.7329%
SHORT TERM DEBT	0.0196%
CUSTOMER DEPOSITS	0.1940%
TAX CREDITS -WEIGHTED	0.0007%
TOTAL DEBT	**1.9473%**
EQUITY COMPONENTS:	
PREFERRED STOCK	0.0000%
COMMON EQUITY	4.6999%
TAX CREDITS -WEIGHTED	0.0019%
TOTAL EQUITY	**4.7019%**
TOTAL	6.6492%
PRE-TAX EQUITY	7.6546%
PRE-TAX TOTAL	9.6019%

Note:
(a) Reflects approved capital structure and ROE reflected in Docket 080677-EI which ended in Order No. PSC-10-0153-FOF-EI. The above capital structure started effective March 2010.
(b) This capital structure applies only to Convertible Investment Tax Credit (C-ITC).

APPENDIX I

ENVIRONMENTAL COST RECOVERY
COMMISSION FORMS 42-1E THROUGH 42-9E

JANUARY 2011 - DECEMBER 2011
ACTUAL/ESTIMATED TRUE-UP

8-26-11
Revised TJK-2
DOCKET NO. 110007-EI
EXHIBIT________
PAGES 1-72

Form 42-1E

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Actual/Estimated True-up
for the period January 2011 through December 2011

Line No.			
1	Over/(Under) Recovery for the Current Period (Form 42-2E Page 2 of 2, Line 5)	$	8,647,642
2	Interest Provision (Form 42-2E Page 2 of 2, Line 6)	$	61,040
3	Sum of Current Period Adjustments (Form 42-2E, Page 2 of 2, Line 10)	$	-
4	Actual/Estimated True-up to be refunded/(recovered) in January 2011 through December 2011	$	8,708,682

( ) Reflects Underrecovery

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Actual/Estimated True-up Amount for the Period
January 2011 through December 2011

Line No.		ACTUAL January	ACTUAL February	ACTUAL March	ACTUAL April	ACTUAL May	ACTUAL June
1	ECRC Revenues (net of Revenue Taxes)	$13,775,033	$11,515,412	$9,034,033	$10,645,090	$11,348,251	$12,797,516
2	True-up Provision (Order No. PSC-11-0083-FOF-EI)	3,351,777	3,351,777	3,351,777	3,351,777	3,351,777	3,351,777
3	ECRC Revenues Applicable to Period (Lines 1 + 2)	17,126,810	14,867,189	12,385,810	13,996,867	14,700,028	16,149,293
4	Jurisdictional ECRC Costs						
	a - O&M Activities (Form 42-5E, Line 9)	1,587,230	1,236,474	1,914,752	2,054,131	1,665,532	5,283,876
	b - Capital Investment Projects (Form 42-7E, Line 9)	12,091,789	12,123,966	11,906,332	11,949,386	12,203,665	12,375,493
	c - Total Jurisdictional ECRC Costs	13,679,019	13,360,440	13,821,084	14,003,517	13,869,197	17,659,369
5	*Over/(Under) Recovery (Line 3 - Line 4c)*	3,447,791	1,506,749	(1,435,274)	(6,650)	830,831	(1,510,076)
6	Interest Provision (Form 42-3E, Line 10)	9,437	9,257	7,713	6,024	4,978	4,060
7	Prior Periods True-Up to be (Collected)/Refunded in 2011	40,221,324	40,326,775	38,491,004	33,711,666	30,359,263	27,843,296
	a - Deferred True-Up from 2010 (Form 42-1A, Line 7) *Final True-up filed April 1, 2011*	5,036,425	5,036,425	5,036,425	5,036,425	5,036,425	5,036,425
8	True-Up Collected /(Refunded) (See Line 2)	(3,351,777)	(3,351,777)	(3,351,777)	(3,351,777)	(3,351,777)	(3,351,777)
9	End of Period True-Up (Lines 5+6+7+7a+8)	45,363,200	43,527,429	38,748,092	35,395,689	32,879,721	28,021,928
10	Adjustments to Period Total True-Up Including Interest						
11	End of Period Total Net True-Up (Lines 9+10)	$45,363,200	$43,527,429	$38,748,092	$35,395,689	$32,879,721	$28,021,928

REVISED 8-26-11

Form 42-2E
Page 2 of 2

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Actual/Estimated True-up Amount for the Period
January 2011 through December 2011

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)	$12,155,235	$13,480,170	$13,560,678	$11,595,680	$10,106,870	$9,890,202	$139,904,171
2	True-up Provision (Order No. PSC-11-0083-FOF-EI)	3,351,777	3,351,777	3,351,777	3,351,777	3,351,777	3,351,777	40,221,324
3	ECRC Revenues Applicable to Period (Lines 1 + 2)	15,507,012	16,831,947	16,912,455	14,947,457	13,458,647	13,241,979	180,125,495
4	Jurisdictional ECRC Costs							
	a - O&M Activities (Form 42-5E, Line 9)	(860,591)	2,026,216	1,900,934	2,212,026	2,224,232	2,419,718	23,664,530
	b - Capital Investment Projects (Form 42-7E, Line 9)	12,371,443	12,429,680	12,493,961	12,552,767	12,608,754	12,706,087	147,813,323
	c - Total Jurisdictional ECRC Costs	11,510,852	14,455,896	14,394,895	14,764,793	14,832,986	15,125,805	171,477,853
5	Over/(Under) Recovery (Line 3 - Line 4c)	3,996,160	2,376,051	2,517,560	182,664	(1,374,339)	(1,883,826)	8,647,642
6	Interest Provision (Form 42-3E, Line 10)	3,779	3,758	3,637	3,371	2,845	2,181	61,040
7	Prior Periods True-Up to be (Collected)/Refunded in 2011	22,985,502	23,633,665	22,661,697	21,831,117	18,665,376	13,942,104	40,221,324
	a - Deferred True-Up from 2010 (Form 42-1A, Line 7) Final True-up filed April 1, 2011	5,036,425	5,036,425	5,036,425	5,036,425	5,036,425	5,036,425	
8	True-Up Collected /(Refunded) (See Line 2)	(3,351,777)	(3,351,777)	(3,351,777)	(3,351,777)	(3,351,777)	(3,351,777)	(40,221,324)
9	End of Period True-Up (Lines 5+6+7+7a+8)	28,670,090	27,698,122	26,867,543	23,701,801	18,978,530	13,745,108	8,708,682
10	Adjustments to Period Total True-Up Including Interest							
11	End of Period Total Net True-Up (Lines 9+10)	$28,670,090	$27,698,122	$26,867,543	$23,701,801	$18,978,530	$13,745,108	$8,708,682

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Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Actual/Estimated True-up Amount for the Period
January 2011 through December 2011

Interest Provision (in Dollars)

Line No.		January	February	March	April	May	June
1	Beginning True-Up Amount (Form 42-2E, Lines 7 + 7a + 10)	$45,257,749	$45,363,200	$43,527,429	$38,748,092	$35,395,689	$32,879,721
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2E, Lines 5 + 8)	45,353,763	43,518,172	38,740,379	35,389,665	32,874,743	28,017,868
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	$90,611,513	$88,881,373	$82,267,808	$74,137,757	$68,270,432	$60,897,589
4	Average True-Up Amount (Line 3 x 1/2)	$45,305,756	$44,440,686	$41,133,904	$37,068,878	$34,135,216	$30,448,794
5	Interest Rate (First Day of Reporting Month)	0.25000%	0.25000%	0.25000%	0.20000%	0.19000%	0.16000%
6	Interest Rate (First Day of Subsequent Month)	0.25000%	0.25000%	0.20000%	0.19000%	0.16000%	0.16000%
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	0.50000%	0.50000%	0.45000%	0.39000%	0.35000%	0.32000%
8	Average Interest Rate (Line 7 x 1/2)	0.25000%	0.25000%	0.22500%	0.19500%	0.17500%	0.16000%
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.02083%	0.02083%	0.01875%	0.01625%	0.01458%	0.01333%
10	Interest Provision for the Month (Line 4 x Line 9)	$9,437	$9,257	$7,713	$6,024	$4,978	$4,060

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Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Actual/Estimated True-up Amount for the Period
January 2011 through December 2011

Interest Provision (In Dollars)

Line No.		July	August	September	October	November	December	End of Period Amount
1	Beginning True-Up Amount (Form 42-2E, Lines 7 + 7a + 10)	$28,021,928	$28,670,090	$27,698,122	$26,867,543	$23,701,801	$18,978,530	N/A
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2E, Lines 5 + 8)	28,666,311	27,694,364	26,863,906	23,698,430	18,975,685	13,742,927	N/A
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	$56,688,239	$56,364,454	$54,562,028	$50,565,973	$42,677,486	$32,721,457	N/A
4	Average True-Up Amount (Line 3 x 1/2)	$28,344,119	$28,182,227	$27,281,014	$25,282,986	$21,338,743	$16,360,728	N/A
5	Interest Rate (First Day of Reporting Month)	0.16000%	0.16000%	0.16000%	0.16000%	0.16000%	0.16000%	N/A
6	Interest Rate (First Day of Subsequent Month)	0.16000%	0.16000%	0.16000%	0.16000%	0.16000%	0.16000%	N/A
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	0.32000%	0.32000%	0.32000%	0.32000%	0.32000%	0.32000%	N/A
8	Average Interest Rate (Line 7 x 1/2)	0.16000%	0.16000%	0.16000%	0.16000%	0.16000%	0.16000%	N/A
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.01333%	0.01333%	0.01333%	0.01333%	0.01333%	0.01333%	N/A
10	Interest Provision for the Month (Line 4 x Line 9)	$3,779	$3,758	$3,637	$3,371	$2,845	$2,181	$61,040

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Actual/Estimated True-Up Amount for the Period
January 2011 - December 2011

Variance Report of O&M Activities
(in Dollars)

Line		(1) Actual Estimated	(2) Original Projection	(3) Variance Amount	(4) Variance Percent
1	Description of O&M Activities				
1	Air Operating Permit Fees-O&M	$1,183,121	$1,281,586	($98,465)	-7.7%
3a	Continuous Emission Monitoring Systems-O&M	$866,057	$722,698	$143,359	19.8%
5a	Maintenance of Stationary Above Ground Fue Storage Tanks-O&M	$1,666,131	$1,706,149	($40,018)	-2.3%
8a	Oil Spill Cleanup/Response Equipment-O&M	$218,477	$197,600	$20,877	10.6%
13	RCRA Corrective Action-O&M	$92,127	$0	$92,127	NA
14	NPDES Permit Fees-O&M	$124,400	$124,400	$0	0.0%
17a	Disposal of Noncontainerized Liquid Waste-O&M	$65,000	$226,000	($161,000)	-71.2%
19a	Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	$2,823,488	$3,259,000	($435,512)	-13.4%
19b	Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	$1,513,458	$823,000	$690,458	83.9%
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	NA
NA	Amortization of Gains on Sales of Emissions Allowances	($279,501)	($319,373)	$39,872	-12.5%
21	St. Lucie Turtle Net	$0	$0	$0	NA
22	Pipeline Integrity Management	$235,392	$225,000	$10,392	4.6%
23	SPCC-Spill Prevention, Control & Countermeasures	$1,069,671	$896,500	$173,171	19.3%
24	Manatee Reburn	$602,856	$500,000	$102,856	20.6%
25	Port Everglades ESP	$649,118	$200,000	$449,118	224.6%
26	UST Replacement/Removal	$0	$0	$0	NA
27	Lowest Quality Water Source	$315,621	$321,482	($5,861)	-1.8%
28	CWA 316(b) Phase II Rule	$122,329	$130,000	($7,671)	-5.9%
29	SCR Consumables	$383,263	$400,000	($16,737)	-4.2%
30	HBMP	$30,541	$33,000	($2,459)	-7.5%
31	CAIR Compliance	$1,617,761	$1,910,000	($292,239)	-15.3%
32	BART Compliance	$0	$0	$0	NA
33	CAMR Compliance	$2,335,558	$3,903,000	($1,567,442)	-40.2%
34	St. Lucie Cooling Water System Inspection & Maintenance	$671,676	$165,000	$506,676	307.1%
35	Martin Plant Drinking Water System Compliance	$22,174	$17,000	$5,174	30.4%
36	Low-Level Radioactive Waste Storage	$0	$0	$0	NA
37	DeSoto Next Generation Solar Energy Center	$970,099	$1,038,879	($68,780)	-6.6%
38	Space Coast Next Generatino Solar Energy Center	$530,047	$626,422	($96,375)	-15.4%
39	Martin Next Generation Solar Energy Center	$2,422,554	$2,445,024	($22,470)	-0.9%
40	Greenhouse Gas Reduction Program	$55,000	$55,000	$0	0.0%
41	Manatee Temporary Heating System Project	$1,339,480	$474,449	$865,031	182.3%
42	Turkey Point Cooling Canal Monitoring Plan	$2,721,497	$2,070,000	$651,497	31.5%
43	NESHAP Information Collection Request Project	$8,385	$0	$8,385	NA
44	Martin Plant Barley Barber Swamp Iron Mitigation Project	$0	$5,000	($5,000)	-100.0%
46	St. Lucie Cooling Water Discharge Monitoring Project	$240,677	$0	$240,677	NA
47	NPDES Permit Renewal Requirements	$33,000	$0	$33,000	NA
2	Total O&M Activities	$24,089,224	$22,876,584	$1,212,640	5.3%
3	Recoverable Costs Allocated to Energy	$11,860,944	$11,662,721	$198,223	1.7%
4a	Recoverable Costs Allocated to CP Demand	$9,684,908	$8,234,979	$1,449,930	17.6%
4b	Recoverable Costs Allocated to GCP Demand	$2,543,372	$2,978,884	($435,512)	-14.6%

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-11-0083-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 Actual / Estimated Amount for the Period
January 2011 - December 2011

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	$ 106,665	$ 116,416	$ 106,415	$ 106,415	$ 106,415	$ 91,539	$ 633,865
	3a Continuous Emission Monitoring Systems-O&M	183,180	17,050	14,048	92,001	22,205	30,754	359,238
	5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	2,214	402	0	17,459	240,021	364,421	624,516
	8a Oil Spill Cleanup/Response Equipment-O&M	2,690	16,917	14,876	12,350	11,448	18,790	77,071
	13 RCRA Corrective Action-O&M	0	4,048	0	0	0	6,479	10,527
	14 NPDES Permit Fees-O&M	124,400	0	0	0	0	0	124,400
	17a Disposal of Noncontainerized Liquid Waste-O&M	0	0	0	0	0	0	0
	19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	36,700	162,058	132,624	87,810	84,628	184,668	688,488
	19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	(77,980)	229,128	232,364	106,537	219,803	43,105	752,958
	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	(21,426)	(21,426)	(21,426)	(21,426)	(23,500)	(38,921)	(148,125)
	21 St. Lucie Turtle Net	0	0	0	0	0	0	0
	22 Pipeline Integrity Management	15,417	(32,511)	(4,859)	794	144	13,193	(7,823)
	23 SPCC - Spill Prevention, Control & Countermeasures	67,139	53,624	105,614	69,482	94,930	116,608	507,397
	24 Manatee Reburn	31,753	78,062	130,909	34,388	2,916	12,813	290,841
	25 Pt. Everglades ESP Technology	28,009	20,131	26,957	26,729	10,166	20,542	132,535
	26 UST Replacement/Removal	0	0	0	0	0	0	0
	27 Lowest Quality Water Source	28,276	24,130	25,777	26,483	25,128	26,072	153,866
	28 CWA 316(b) Phase II Rule	3,514	5,284	10,745	6,476	8,108	4,201	38,328
	29 SCR Consumables	25,384	29,452	63,490	26,668	30,127	22,826	197,947
	30 HBMP	1,712	1,720	5,088	5,088	1,712	1,720	17,041
	31 CAIR Compliance	119,009	116,133	151,065	131,710	162,859	118,730	799,505
	32 BART Compliance	0	0	0	0	0	0	0
	33 CAMR Compliance	197,212	42,966	197,100	121,199	126,638	180,037	865,151
	34 St. Lucie Cooling Water System Inspection & Maintenance	164,795	14,350	148,697	225,430	94,139	12,265	659,676
	35 Martin Plant Drinking Water System Compliance	0	0	3,696	1,848	1,848	3,695	11,086
	36 Low-Level Radioactive Waste Storage	0	0	0	0	0	0	0
	37 DeSoto Next Generation Solar Energy Center	90,487	66,075	70,956	80,084	81,984	107,630	497,215
	38 Space Coast Next Generation Solar Energy Center	43,491	33,597	30,610	41,941	32,054	38,264	219,957
	39 Martin Next Generation Solar Energy Center	84,777	117,122	90,212	478,202	77,766	3,460,674	4,308,754
	40 Greenhouse Gas Reduction Program	0	2,500	1,056	0	0	0	3,556
	41 Manatee Temporary Heating System Project	281,268	118,324	131,693	124,395	76,149	147,890	879,718
	42 Turkey Point Cooling Canal Monitoring Plan	128,886	89,681	327,657	328,495	253,580	433,198	1,561,497
	43 NESHAP Information Collection Request Project	0	0	2,385	0	0	0	2,385
	44 Martin Plant Barley Barber Swamp Iron Mitigation Project	0	0	0	0	0	0	0
	46 St. Lucie Cooling Water Discharge Monitoring Project	0	0	0	10,263	5,203	12,297	27,763
	47 NPDES Permit Renewal Requirements	0	0	0	0	0	0	0
2	Total of O&M Activities	$ 1,618,885	$ 1,258,548	$ 1,951,062	$ 2,094,133	$ 1,697,785	$ 5,386,803	$ 14,007,216
3	Recoverable Costs Allocated to Energy	$ 1,074,636	$ 642,036	$ 1,162,303	$ 989,323	$ 794,114	$ 1,039,719	$ 5,702,330
4a	Recoverable Costs Allocated to CP Demand	$ 530,692	$ 477,798	$ 679,478	$ 1,040,343	$ 842,386	$ 4,185,761	$ 7,756,459
4b	Recoverable Costs Allocated to GCP Demand	$ 13,357	$ 138,715	$ 109,281	$ 64,467	$ 61,285	$ 161,325	$ 548,430
5	Retail Energy Jurisdictional Factor	98.02710%	98.02710%	98.02710%	98.02710%	98.02710%	98.02710%	
6a	Retail CP Demand Jurisdictional Factor	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%	
6b	Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	
7	Jurisdictional Energy Recoverable Costs (A)	$ 1,053,630	$ 629,369	$ 1,139,372	$ 969,804	$ 778,447	$ 1,019,206	$ 5,589,828
8a	Jurisdictional CP Demand Recoverable Costs (B)	$ 520,243	$ 468,390	$ 666,099	$ 1,019,860	$ 825,800	$ 4,103,345	$ 7,603,737
8b	Jurisdictional GCP Demand Recoverable Costs (C)	$ 13,357	$ 138,715	$ 109,281	$ 64,467	$ 61,285	$ 161,325	$ 548,430
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 1,587,230	$ 1,236,474	$ 1,914,752	$ 2,054,131	$ 1,665,532	$ 5,283,876	$ 13,741,995

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

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Actual / Estimated Amount for the Period
January 2011 - December 2011

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	$ 91,539	$ 91,539	$ 91,539	$ 91,539	$ 91,539	$ 91,581	$ 549,256	$ 1,183,121			$ 1,183,121
	3a Continuous Emission Monitoring Systems-O&M	176,763	139,933	34,536	36,983	40,296	78,308	506,819	886,057			886,057
	5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	346,989	6,650	0	181,500	185,500	320,976	1,041,615	1,666,131	1,666,131		
	8a Oil Spill Cleanup/Response Equipment-O&M	35,892	20,903	20,903	20,903	20,903	21,902	141,406	218,477			218,477
	13 RCRA Corrective Action-O&M	13,600	13,600	13,600	13,600	13,600	13,600	81,600	92,127	92,127		
	14 NPDES Permit Fees-O&M	0	0	0	0	0	0	0	124,400	124,400		
	17a Disposal of Noncontainerized Liquid Waste-O&M	30,000	32,500	0	2,500	0	0	65,000	65,000			65,000
	19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	294,000	340,000	434,000	425,000	436,000	206,000	2,135,000	2,823,488		2,823,488	
	19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	123,000	135,000	123,000	127,000	148,500	104,000	760,500	1,513,458	1,397,038		116,420
	19c Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(280,116)	(560,232)	(258,569)	(280,116)	(21,547)
	20 Wastewater Discharge Elimination & Reuse	0	0	0	0	0	0	0	0	0		
	NA Amortization of Gains on Sales of Emissions Allowances	(21,896)	(21,896)	(21,896)	(21,896)	(21,896)	(21,896)	(131,375)	(279,501)			(279,501)
	21 St. Lucie Turtle Net	0	0	0	0	0	0	0	0	0		
	22 Pipeline Integrity Management	81,500	5,000	5,000	0	89,215	62,500	243,215	235,392	235,392		
	23 SPCC - Spill Prevention, Control & Countermeasures	136,253	66,500	66,800	68,879	71,000	152,842	562,274	1,069,671	1,069,671		
	24 Manatee Reburn	52,000	15,000	10,608	151,077	41,667	41,663	312,015	602,856			602,856
	25 Pt. Everglades ESP Technology	67,757	121,150	121,150	67,757	72,757	66,012	516,583	649,118			649,118
	26 UST Replacement/Removal	0	0	0	0	0	0	0	0	0		
	27 Lowest Quality Water Source	26,957	26,957	26,957	26,957	26,957	26,970	161,755	315,621	315,621		
	28 CWA 316(b) Phase II Rule	32,154	10,231	7,154	22,154	7,154	7,154	86,001	122,329	122,329		
	29 SCR Consumables	39,000	46,316	24,000	26,000	24,000	26,000	185,316	383,263			383,263
	30 HBMP	2,750	1,750	1,750	1,750	1,750	3,750	13,500	30,541	30,541		
	31 CAIR Compliance	95,427	135,216	129,269	178,266	127,323	152,755	818,256	1,617,761			1,617,761
	32 BART Compliance	0	0	0	0	0	0	0	0			0
	33 CAMR Compliance	390,535	196,672	176,200	180,000	175,000	350,000	1,470,407	2,335,558			2,335,558
	34 St. Lucie Cooling Water System Inspection & Maintenance	2,000	2,000	2,000	2,000	2,000	2,000	12,000	671,676	671,676		
	35 Martin Plant Drinking Water System Compliance	1,848	1,848	1,848	1,848	1,848	1,848	11,088	22,174	22,174		
	36 Low-Level Radioactive Waste Storage	0	0	0	0	0	0	0	0	0		0
	37 DeSoto Next Generation Solar Energy Center	74,274	76,205	69,674	94,174	69,274	89,283	472,884	970,099	970,099		
	38 Space Coast Next Generation Solar Energy Center	41,551	55,077	63,801	45,301	61,551	42,809	310,090	530,047	530,047		
	39 Martin Next Generation Solar Energy Center	(3,200,200)	282,000	282,000	250,000	250,000	250,000	(1,886,200)	2,422,554	2,422,554		
	40 Greenhouse Gas Reduction Program	13,750	0	13,750	0	13,750	10,194	51,444	55,000			55,000
	41 Manatee Temporary Heating System Project	0	24,201	64,967	64,967	142,519	163,108	459,762	1,339,480			1,339,480
	42 Turkey Point Cooling Canal Monitoring Plan	193,000	193,000	193,000	193,000	193,000	195,000	1,160,000	2,721,497			2,721,497
	43 NESHAP Information Collection Request Project	3,000	3,000	0	0	0	0	6,000	8,385			8,385
	44 Martin Plant Barley Barber Swamp Iron Mitigation Project	0	0	0	0	0	0	0	0	0		
	46 St. Lucie Cooling Water Discharge Monitoring Project	19,978	74,727	19,977	43,854	11,334	43,044	212,914	240,677	240,677		
	47 NPDES Permit Renewal Requirements	0	12,200	0	0	10,800	10,000	33,000	33,000	33,000		
2	Total of O&M Activities	$ (883,265)	$ 2,060,593	$ 1,930,901	$ 2,248,427	$ 2,260,655	$ 2,464,697	$ 10,082,009	$ 24,089,224	$ 9,684,908	$ 2,543,372	$ 11,860,944
3	Recoverable Costs Allocated to Energy	$ 1,174,433	$ 1,006,123	$ 867,692	$ 999,070	$ 930,486	$ 1,180,811	$ 6,158,615	$ 11,860,944			
4a	Recoverable Costs Allocated to CP Demand	$ (2,328,355)	$ 737,813	$ 652,552	$ 847,700	$ 917,513	$ 1,101,229	$ 1,928,452	$ 9,684,908			
4b	Recoverable Costs Allocated to GCP Demand	$ 270,657	$ 316,657	$ 410,657	$ 401,657	$ 412,657	$ 182,657	$ 1,994,942	$ 2,543,372			
5	Retail Energy Jurisdictional Factor	98.02710%	98.02710%	98.02710%	98.02710%	98.02710%	98.02710%					
6a	Retail CP Demand Jurisdictional Factor	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%					
6b	Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%					
7	Jurisdictional Energy Recoverable Costs (A)	$ 1,151,263	$ 986,273	$ 850,573	$ 979,359	$ 912,128	$ 1,157,515	$ 6,037,111	$ 11,626,939			
8a	Jurisdictional CP Demand Recoverable Costs (B)	$ (2,282,511)	$ 723,286	$ 639,704	$ 831,010	$ 899,447	$ 1,079,546	$ 1,890,482	$ 9,494,219			
8b	Jurisdictional GCP Demand Recoverable Costs (C)	$ 270,657	$ 316,657	$ 410,657	$ 401,657	$ 412,657	$ 182,657	$ 1,994,942	$ 2,543,372			
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ (860,591)	$ 2,026,216	$ 1,900,934	$ 2,212,026	$ 2,224,232	$ 2,419,718	$ 9,922,535	$ 23,664,530			

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

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Actual/Estimated True-Up Amount for the Period
January 2011 - December 2011

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

Line		(1) Actual Estimated	(2) Original Projections	(3) Variance Amount	(4) Variance Percent
1	Description of Investment Projects				
2	Low NOx Burner Technology-Capital	$ 329,955	$ 329,955	$ (0)	0.0%
3b	Continuous Emission Monitoring Systems-Capital	676,243	676,609	(367)	-0.1%
4b	Clean Closure Equivalency-Capital	2,092	2,092	(0)	0.0%
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	1,037,943	1,059,760	(21,817)	-2.1%
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	1,610	1,610	0	0.0%
8b	Oil Spill Cleanup/Response Equipment-Capital	125,621	136,905	(11,284)	-8.2%
10	Relocate Storm Water Runoff-Capital	8,422	8,422	(0)	0.0%
NA	SO2 Allowances-Negative Return on Investment	(185,051)	(182,674)	(2,377)	1.3%
12	Scherer Discharge Pipeline-Capital	57,309	57,309	(0)	0.0%
17b	Disposal of Noncontainerized Liquid Wate-Capital	0	0	0	0.0%
20	Wastewater Discharge Elimination & Reuse	134,676	162,604	(27,928)	-17.2%
21	St. Lucie Turtle Net	106,246	112,798	(6,552)	-5.8%
22	Pipeline Integrity Management	5,991	6,081	(90)	-1.5%
23	SPCC-Spill Prevention, Control & Countermeasures	2,052,033	2,008,689	43,344	2.2%
24	Manatee Reburn	3,371,252	3,385,522	(14,270)	-0.4%
25	Pt. Everglades ESP Technology	8,230,136	8,230,136	0	0.0%
26	UST Replacement/Removal	32,723	53,369	(20,646)	-38.7%
31	CAIR Compliance	45,557,242	47,030,472	(1,473,230)	-3.1%
33	CAMR Compliance	12,693,336	12,845,546	(152,209)	-1.2%
34	St. Lucie Cooling Water System Inspection & Maintenance	0	139,324	(139,324)	-100.0%
35	Martin Plant Drinking Water System Compliance	27,781	26,472	1,309	4.9%
36	Low-Level Radioactive Waste Storage	465,504	597,580	(132,076)	-22.1%
37	DeSoto Next Generation Solar Energy Center	17,909,434	17,961,840	(52,406)	-0.3%
38	Space Coast Next Generation Solar Energy Center	8,484,479	8,518,231	(33,752)	-0.4%
39	Martin Next Generation Solar Energy Center	48,388,726	48,586,067	(197,340)	-0.4%
40	Greenhouse Gas Reduction Program	0	0	0	0.0%
41	Manatee Temporary Heating System Project	853,668	684,987	168,681	24.6%
42	Turkey Point Cooling Canal Monitoring Plan	407,704	439,010	(31,306)	-7.1%
44	Martin Plant Barley Barber Swamp Iron Mitigation Project	8,002	23,002	(15,001)	-65.2%
2	Total Investment Projects-Recoverable Costs	$ 150,783,076	$ 152,901,720	$ (2,118,644)	-1.4%
3	Recoverable Costs Allocated to Energy	$ 23,065,039	$ 23,242,562	$ (177,524)	-0.8%
4	Recoverable Costs Allocated to Demand	$ 127,718,037	$ 129,659,158	$ (1,941,121)	-1.5%

Notes:
Column(1) is the 12-Month Totals on Form 42-7E
Column(2) is the approved projected amount in accordance with
FPSC Order No. PSC-11-0083-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 Actual / Estimated Amount for the Period
January 2011 - December 2011

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	$ 28,367	$ 28,208	$ 28,050	$ 27,892	$ 27,734	$ 27,575	$ 167,826
3b Continuous Emission Monitoring Systems-Capital	57,428	57,232	57,037	56,842	56,646	56,451	341,636
4b Clean Closure Equivalency-Capital	177	177	176	176	175	175	1,056
5b Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	87,520	87,332	87,144	86,956	86,768	86,543	522,262
7 Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	137	136	136	135	135	134	814
8b Oil Spill Cleanup/Response Equipment-Capital	8,839	8,809	8,773	8,740	8,666	8,612	52,439
10 Relocate Storm Water Runoff-Capital	710	708	707	705	704	703	4,236
NA SO2 Allowances-Negative Return on Investment	(16,354)	(16,182)	(16,011)	(15,839)	(15,681)	(15,522)	(95,589)
12 Scherer Discharge Pipeline-Capital	4,848	4,835	4,821	4,808	4,795	4,782	28,890
17b Disposal of Noncontainerized Liquid Waste-Capital	0	0	0	0	0	0	0
20 Wastewater Discharge Elimination & Reuse	12,778	12,774	12,761	11,626	10,485	10,464	70,887
21 St. Lucie Turtle Net	8,877	8,873	8,869	8,864	8,860	8,856	53,199
22 Pipeline Integrity Management	0	0	0	0	0	0	0
23 SPCC - Spill Prevention, Control & Countermeasures	170,158	170,803	171,329	171,247	171,233	172,976	1,027,746
24 Manatee Reburn	283,965	283,415	282,864	282,314	281,763	281,213	1,695,534
25 Pt. Everglades ESP Technology	692,526	691,311	690,097	688,882	687,667	686,452	4,136,935
26 UST Removal / Replacement	4,485	4,478	4,472	4,136	3,802	3,801	25,174
31 CAIR Compliance	3,568,582	3,599,441	3,381,151	3,433,307	3,674,055	3,828,900	21,485,437
33 CAMR Compliance	1,060,802	1,059,868	1,060,084	1,060,457	1,061,018	1,058,774	6,361,002
35 Martin Plant Drinking Water System Compliance	2,224	2,221	2,218	2,214	2,211	2,927	14,015
36 Low-Level Radioactive Waste Storage	0	0	0	0	25,951	53,508	79,459
37 DeSoto Next Generation Solar Energy Center	1,503,927	1,502,255	1,500,406	1,498,717	1,497,263	1,495,084	8,997,653
38 Space Coast Next Generation Solar Energy Center	715,904	714,232	712,740	711,299	709,628	707,933	4,271,737
39 Martin Next Generation Solar Energy Center	4,037,210	4,042,747	4,043,397	4,042,278	4,041,408	4,040,339	24,247,380
41 Manatee Temporary Heating System Project	66,968	68,714	69,749	69,787	69,741	69,670	414,630
42 Turkey Point Cooling Canal Monitoring Plan	34,650	35,166	34,577	33,921	33,824	33,781	205,920
44 Martin Plant Barley Barber Swamp Iron Mitigation Project	0	0	0	0	0	0	0
2 Total Investment Projects - Recoverable Costs	$ 12,334,730	$ 12,367,553	$ 12,145,545	$ 12,189,466	$ 12,448,852	$ 12,624,132	$ 74,110,278
3 Recoverable Costs Allocated to Energy	$ 1,914,301	$ 1,915,028	$ 1,896,153	$ 1,897,735	$ 1,915,877	$ 1,927,551	$ 11,466,644
4 Recoverable Costs Allocated to Demand	$ 10,420,429	$ 10,452,525	$ 10,249,393	$ 10,291,731	$ 10,532,975	$ 10,696,581	$ 62,643,634
5 Retail Energy Jurisdictional Factor	98.02710%	98.02710%	98.02710%	98.02710%	98.02710%	98.02710%	
6 Retail Demand Jurisdictional Factor	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%	
7 Jurisdictional Energy Recoverable Costs (B)	$ 1,876,533	$ 1,877,246	$ 1,858,744	$ 1,860,294	$ 1,878,079	$ 1,889,522	$ 11,240,418
8 Jurisdictional Demand Recoverable Costs (C)	$ 10,215,256	$ 10,246,720	$ 10,047,587	$ 10,089,092	$ 10,325,586	$ 10,485,971	$ 61,410,212
9 Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 12,091,789	$ 12,123,966	$ 11,906,331	$ 11,949,386	$ 12,203,665	$ 12,375,493	$ 72,650,630

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

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Actual / Estimated Amount for the Period
January 2011 - December 2011

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	$ 27,417	$ 27,259	$ 27,101	$ 26,942	$ 26,784	$ 26,626	$ 162,129	$ 329,955		$ 329,955
3b Continuous Emission Monitoring Systems-Capital	56,256	56,061	55,865	55,670	55,475	55,280	334,607	676,243		676,243
4b Clean Closure Equivalency-Capital	174	174	173	172	172	171	1,036	2,092	1,931	161
5b Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	86,372	86,238	86,050	85,862	85,674	85,486	515,681	1,037,943	958,101	79,842
7 Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	134	133	133	132	132	131	796	1,610	1,487	123
8b Oil Spill Cleanup/Response Equipment-Capital	10,541	12,188	12,636	12,784	12,722	12,311	73,181	125,621	115,957	9,664
10 Relocate Storm Water Runoff-Capital	701	700	698	697	695	694	4,186	8,422	7,774	648
NA SO2 Allowances-Negative Return on Investment	(15,348)	(15,173)	(14,998)	(14,823)	(14,648)	(14,472)	(89,462)	(185,051)		(185,051)
12 Scherer Discharge Pipeline-Capital	4,769	4,756	4,743	4,730	4,717	4,704	28,419	57,309	52,901	4,408
17b Disposal of Noncontainerized Liquid Waste-Capital	0	0	0	0	0	0	0	0	0	0
20 Wastewater Discharge Elimination &Reuse	11,919	10,413	10,393	10,374	10,355	10,335	63,789	134,676	124,316	10,360
21 St. Lucie Turtle Net	8,852	8,847	8,843	8,839	8,835	8,831	53,047	106,246	98,073	8,173
22 Pipeline Integrity Management	0	0	0	0	0	5,991	5,991	5,991	5,530	461
23 SPCC - Spill Prevention, Control & Countermeasures	172,380	170,750	170,615	170,430	170,212	169,900	1,024,287	2,052,033	1,894,184	157,849
24 Manatee Reburn	280,662	280,112	279,562	279,011	278,461	277,910	1,675,718	3,371,252		3,371,252
25 Pt. Everglades ESP Technology	685,237	684,022	682,808	681,593	680,378	679,163	4,093,202	8,230,136		8,230,136
26 UST Removal / Replacement	2,415	1,030	1,028	1,027	1,025	1,023	7,548	32,723	30,205	2,518
31 CAIR Compliance	3,830,314	3,898,313	3,975,777	4,042,645	4,108,557	4,216,199	24,071,805	45,557,242	42,052,839	3,504,403
33 CAMR Compliance	1,056,040	1,055,715	1,055,582	1,055,660	1,055,229	1,054,108	6,332,334	12,693,336	11,716,926	976,410
35 Martin Plant Drinking Water System Compliance	2,794	2,201	2,198	2,194	2,191	2,188	13,767	27,781	25,644	2,137
36 Low-Level Radioactive Waste Storage	59,896	65,000	65,318	65,306	65,280	65,245	386,045	465,504	429,696	35,808
37 DeSoto Next Generation Solar Energy Center	1,491,494	1,488,276	1,485,757	1,483,839	1,481,821	1,480,594	8,911,781	17,909,434	16,531,785	1,377,649
38 Space Coast Next Generation Solar Energy Center	706,295	704,652	702,971	701,289	699,608	697,926	4,212,742	8,484,479	7,831,827	652,652
39 Martin Next Generation Solar Energy Center	4,036,514	4,033,088	4,027,180	4,021,957	4,015,253	4,007,354	24,141,346	48,388,726	44,666,516	3,722,209
41 Manatee Temporary Heating System Project	69,585	69,523	69,461	73,595	78,155	78,719	439,038	853,668	788,001	65,667
42 Turkey Point Cooling Canal Monitoring Plan	33,738	33,695	33,652	33,609	33,566	33,523	201,784	407,704	376,342	31,362
44 Martin Plant Barley Barber Swamp Iron Mitigation Project	847	1,435	1,433	1,431	1,429	1,427	8,002	8,002	8,002	
2 Total Investment Projects - Recoverable Costs	$ 12,620,000	$ 12,679,408	$ 12,744,980	$ 12,804,966	$ 12,862,078	$ 12,961,367	$ 76,672,798	$ 150,783,076	$ 127,718,037	$23,065,039
3 Recoverable Costs Allocated to Energy	$ 1,925,373	$ 1,928,103	$ 1,931,353	$ 1,934,174	$ 1,936,773	$ 1,942,617	$ 11,598,394	$ 23,065,039		
4 Recoverable Costs Allocated to Demand	$ 10,694,627	$ 10,751,304	$ 10,813,626	$ 10,870,792	$ 10,925,305	$ 11,018,750	$ 65,074,404	$ 127,718,037		
5 Retail Energy Jurisdictional Factor	98.02710%	98.02710%	98.02710%	98.02710%	98.02710%	98.02710%				
6 Retail Demand Jurisdictional Factor	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%				
7 Jurisdictional Energy Recoverable Costs (B)	$ 1,887,387	$ 1,890,064	$ 1,893,250	$ 1,896,015	$ 1,898,563	$ 1,904,291	$ 11,369,570	$ 22,609,988		
8 Jurisdictional Demand Recoverable Costs (C)	$ 10,484,055	$ 10,539,616	$ 10,600,711	$ 10,656,752	$ 10,710,191	$ 10,801,796	$ 63,793,121	$ 125,203,333		
9 Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 12,371,442	$ 12,429,680	$ 12,493,961	$ 12,552,767	$ 12,608,754	$ 12,706,087	$ 75,162,691	$ 147,813,321		

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

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$9,896,803	9,896,803	9,896,803	9,896,803	9,896,803	9,896,803	9,896,803	n/a
3.	Less: Accumulated Depreciation	$8,813,243	8,833,019	8,852,794	8,872,569	8,892,345	8,912,120	8,931,895	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,083,559	$1,063,784	$1,044,009	$1,024,234	$1,004,458	$984,683	$964,908	n/a
6.	Average Net Investment		1,073,672	1,053,897	1,034,121	1,014,346	994,571	974,795	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		6,849	6,723	6,597	6,471	6,344	6,218	$39,202
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		1,742	1,710	1,678	1,646	1,614	1,582	$9,973
8.	Investment Expenses								
	a. Depreciation (E)		19,775	19,775	19,775	19,775	19,775	19,775	$118,652
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$28,367	$28,208	$28,050	$27,892	$27,734	$27,575	$167,826

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$9,896,803	9,896,803	9,896,803	9,896,803	9,896,803	9,896,803	9,896,803	n/a
3.	Less: Accumulated Depreciation	$8,931,895	8,951,670	8,971,446	8,991,221	9,010,996	9,030,772	9,050,547	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$964,908	$945,132	$925,357	$905,582	$885,807	$866,031	$846,256	n/a
6.	Average Net Investment		955,020	935,245	915,469	895,694	875,919	856,144	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		6,092	5,966	5,840	5,714	5,587	5,461	73,862
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		1,550	1,518	1,486	1,454	1,421	1,389	18,790
8.	Investment Expenses								
	a. Depreciation (E)		19,775	19,775	19,775	19,775	19,775	19,775	237,303
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$27,417	$27,259	$27,101	$26,942	$26,784	$26,626	$329,955

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$10,232,475	10,232,475	10,232,475	10,232,475	10,232,475	10,232,475	10,232,475	n/a
3.	Less: Accumulated Depreciation	$6,092,959	6,117,360	6,141,762	6,166,163	6,190,565	6,214,966	6,239,368	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$4,139,517	$4,115,115	$4,090,713	$4,066,312	$4,041,910	$4,017,509	$3,993,107	n/a
6.	Average Net Investment		4,127,316	4,102,914	4,078,513	4,054,111	4,029,710	4,005,308	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		26,328	26,172	26,017	25,861	25,706	25,550	$155,634
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		6,698	6,658	6,619	6,579	6,539	6,500	$39,593
8.	Investment Expenses								
	a. Depreciation (E)		24,402	24,402	24,402	24,402	24,402	24,402	$146,409
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$57,428	$57,232	$57,037	$56,842	$56,646	$56,451	$341,636

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other		$0	$0	$0	$0	$0	$0	
2.	Plant-In-Service/Depreciation Base (A)	$10,232,475	10,232,475	10,232,475	10,232,475	10,232,475	10,232,475	10,232,475	n/a
3.	Less: Accumulated Depreciation	$6,239,368	6,263,770	6,288,171	6,312,573	6,336,974	6,361,376	6,385,777	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$3,993,107	$3,968,706	$3,944,304	$3,919,902	$3,895,501	$3,871,099	$3,846,698	n/a
6.	Average Net Investment		3,980,906	3,956,505	3,932,103	3,907,702	3,883,300	3,858,899	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		25,394	25,239	25,083	24,927	24,772	24,616	305,664
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		6,460	6,421	6,381	6,341	6,302	6,262	77,760
8.	Investment Expenses								
	a. Depreciation (E)		24,402	24,402	24,402	24,402	24,402	24,402	292,819
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$56,256	$56,061	$55,865	$55,670	$55,475	$55,280	$676,243

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$41,612	41,612	41,612	41,612	41,612	41,612	41,612	n/a
3.	Less: Accumulated Depreciation	$28,091	28,161	28,230	28,300	28,369	28,439	28,508	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$13,520	$13,451	$13,381	$13,312	$13,242	$13,173	$13,103	n/a
6.	Average Net Investment		13,486	13,416	13,347	13,277	13,208	13,138	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		86	86	85	85	84	84	$510
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		22	22	22	22	21	21	$130
8.	Investment Expenses								
	a. Depreciation (E)		70	70	70	70	70	70	$417
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$177	$177	$176	$176	$175	$175	$1,056

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$41,612	41,612	41,612	41,612	41,612	41,612	41,612	n/a
3.	Less: Accumulated Depreciation	$28,508	28,578	28,647	28,717	28,786	28,856	28,925	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$13,103	$13,034	$12,964	$12,895	$12,825	$12,756	$12,686	n/a
6.	Average Net Investment		13,069	12,999	12,930	12,860	12,791	12,721	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		83	83	82	82	82	81	1,003
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		21	21	21	21	21	21	255
8.	Investment Expenses								
	a. Depreciation (E)		70	70	70	70	70	70	834
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$174	$174	$173	$172	$172	$171	$2,092

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	($7,176)	($7,176)
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$11,733,316	11,733,316	11,733,316	11,733,316	11,733,316	11,733,316	11,726,140	n/a
3.	Less: Accumulated Depreciation	$3,719,660	3,743,150	3,766,640	3,790,130	3,813,620	3,837,110	3,860,592	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$8,013,656	$7,990,166	$7,966,676	$7,943,186	$7,919,696	$7,896,206	$7,865,548	n/a
6.	Average Net Investment		8,001,911	7,978,421	7,954,931	7,931,441	7,907,951	7,880,877	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		51,044	50,894	50,744	50,595	50,445	50,272	$303,995
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		12,986	12,947	12,909	12,871	12,833	12,789	$77,335
8.	Investment Expenses								
	a. Depreciation (E)		23,490	23,490	23,490	23,490	23,490	23,482	$140,932
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$87,520	$87,332	$87,144	$86,956	$86,768	$86,543	$522,262

Notes:

(A) 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 55-59.

(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$11,000	$0	$0	$0	$0	$0	$3,824
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$11,726,140	11,737,140	11,737,140	11,737,140	11,737,140	11,737,140	11,737,140	n/a
3.	Less: Accumulated Depreciation	$3,860,592	3,884,076	3,907,569	3,931,062	3,954,555	3,978,049	4,001,542	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$7,865,548	$7,853,064	$7,829,571	$7,806,078	$7,782,585	$7,759,092	$7,735,599	n/a
6.	Average Net Investment		7,859,306	7,841,318	7,817,825	7,794,331	7,770,838	7,747,345	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		50,135	50,020	49,870	49,720	49,570	49,420	602,729
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		12,754	12,725	12,687	12,649	12,611	12,572	153,333
8.	Investment Expenses								
	a. Depreciation (E)		23,484	23,493	23,493	23,493	23,493	23,493	281,881
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$86,372	$86,238	$86,050	$85,862	$85,674	$85,486	$1,037,943

Notes:

(A) 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 55-59.

(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$31,030	31,030	31,030	31,030	31,030	31,030	31,030	n/a
3.	Less: Accumulated Depreciation	$21,643	21,705	21,768	21,830	21,892	21,954	22,016	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$9,387	$9,325	$9,262	$9,200	$9,138	$9,076	$9,014	n/a
6.	Average Net Investment		9,356	9,293	9,231	9,169	9,107	9,045	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		60	59	59	58	58	58	$352
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		15	15	15	15	15	15	$90
8.	Investment Expenses								
	a. Depreciation (E)		62	62	62	62	62	62	$372
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$137	$136	$136	$135	$135	$134	$814

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

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

Line	Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1. Investments								
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0
d. Other								
2. Plant-In-Service/Depreciation Base (A)	$31,030	31,030	31,030	31,030	31,030	31,030	31,030	n/a
3. Less: Accumulated Depreciation	$22,016	22,078	22,140	22,202	22,264	22,326	22,388	n/a
4. CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5. Net Investment (Lines 2 - 3 + 4)	$9,014	$8,952	$8,890	$8,828	$8,766	$8,704	$8,642	n/a
6. Average Net Investment		8,983	8,921	8,859	8,797	8,735	8,673	n/a
7. Return on Average Net Investment								
a. Equity Component grossed up for taxes (B)		57	57	57	56	56	55	690
b. Debt Component (Line 6 x debt rate x 1/12) (C)		15	14	14	14	14	14	176
8. Investment Expenses								
a. Depreciation (E)		62	62	62	62	62	62	745
b. Amortization (F)								
c. Dismantlement (G)								
d. Property Expenses								
e. Other								
9. Total System Recoverable Expenses (Lines 7 & 8)		$134	$133	$133	$132	$132	$131	$1,610

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

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

Line	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1. Investments								
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		($1,682)	$4,413	$0	$0	$0	$0	$2,731
c. Retirements		($1,682)	$41	$0	$0	$0	$0	($1,641)
d. Other								
2. Plant-In-Service/Depreciation Base (A)	$540,143	538,461	542,874	542,874	542,874	542,874	542,874	n/a
3. Less: Accumulated Depreciation	$269,677	274,697	281,446	288,154	294,883	301,591	308,299	n/a
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	n/a
5. Net Investment (Lines 2 - 3 + 4)	$270,466	$263,764	$261,428	$254,720	$247,991	$241,283	$234,575	n/a
6. Average Net Investment		267,115	262,596	258,074	251,355	244,637	237,929	n/a
7. Return on Average Net Investment								
a. Equity Component grossed up for taxes (B)		1,704	1,675	1,646	1,603	1,561	1,518	$9,707
b. Debt Component (Line 6 x debt rate x 1/12) (C)		433	426	419	408	397	386	$2,469
8. Investment Expenses								
a. Depreciation (E)		6,702	6,708	6,708	6,729	6,708	6,708	$40,263
b. Amortization (F)								
c. Dismantlement (G)								
d. Property Expenses								
e. Other								
9. Total System Recoverable Expenses (Lines 7 & 8)		$8,839	$8,809	$8,773	$8,740	$8,666	$8,612	$52,439

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$368,963	$17,948	$17,000	$0	$0	$0	$406,642
	c. Retirements		$306	($12,052)	$0	$0	$0	$0	($13,387)
	d. Other								0
2.	Plant-In-Service/Depreciation Base (A)	$542,874	911,837	929,785	946,785	946,785	946,785	946,785	n/a
3.	Less: Accumulated Depreciation	$308,299	315,823	311,099	318,747	326,536	334,326	341,766	n/a
4.	CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$234,575	$596,014	$618,686	$628,038	$620,248	$612,459	$605,019	n/a
6.	Average Net Investment		415,294	607,350	623,362	624,143	616,354	608,739	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		2,649	3,874	3,976	3,981	3,932	3,883	32,003
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		674	986	1,012	1,013	1,000	988	8,142
8.	Investment Expenses								
	a. Depreciation (E)		7,218	7,328	7,648	7,790	7,790	7,440	85,476
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$10,541	$12,188	$12,636	$12,784	$12,722	$12,311	$125,621

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$117,794	117,794	117,794	117,794	117,794	117,794	117,794	n/a
3.	Less: Accumulated Depreciation	$51,106	51,282	51,459	51,636	51,812	51,989	52,166	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$66,688	$66,512	$66,335	$66,158	$65,981	$65,805	$65,628	n/a
6.	Average Net Investment		66,600	66,423	66,246	66,070	65,893	65,716	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		425	424	423	421	420	419	$2,532
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		108	108	108	107	107	107	$644
8.	Investment Expenses								
	a. Depreciation (E)		177	177	177	177	177	177	$1,060
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$710	$708	$707	$705	$704	$703	$4,236

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$117,794	117,794	117,794	117,794	117,794	117,794	117,794	n/a
3.	Less: Accumulated Depreciation	$52,166	52,342	52,519	52,696	52,873	53,049	53,226	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$65,628	$65,451	$65,275	$65,098	$64,921	$64,745	$64,568	n/a
6.	Average Net Investment		65,540	65,363	65,186	65,010	64,833	64,656	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		418	417	416	415	414	412	5,024
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		106	106	106	105	105	105	1,278
8.	Investment Expenses								
	a. Depreciation (E)		177	177	177	177	177	177	2,120
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$701	$700	$698	$697	$695	$694	$8,422

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$864,260	864,260	864,260	864,260	864,260	864,260	864,260	n/a
3.	Less: Accumulated Depreciation	$461,625	463,257	464,889	466,522	468,154	469,786	471,419	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$402,636	$401,003	$399,371	$397,739	$396,107	$394,474	$392,842	n/a
6.	Average Net Investment		401,820	400,187	398,555	396,923	395,290	393,658	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		2,563	2,553	2,542	2,532	2,522	2,511	$15,223
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		652	649	647	644	641	639	$3,873
8.	Investment Expenses								
	a. Depreciation (E)		1,632	1,632	1,632	1,632	1,632	1,632	$9,794
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$4,848	$4,835	$4,821	$4,808	$4,795	$4,782	$28,890

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$864,260	864,260	864,260	864,260	864,260	864,260	864,260	n/a
3.	Less: Accumulated Depreciation	$471,419	473,051	474,683	476,316	477,948	479,580	481,213	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$392,842	$391,210	$389,577	$387,945	$386,313	$384,680	$383,048	n/a
6.	Average Net Investment		392,026	390,393	388,761	387,129	385,496	383,864	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		2,501	2,490	2,480	2,469	2,459	2,449	30,071
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		636	634	631	628	626	623	7,650
8.	Investment Expenses								
	a. Depreciation (E)		1,632	1,632	1,632	1,632	1,632	1,632	19,588
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$4,769	$4,756	$4,743	$4,730	$4,717	$4,704	$57,309

Notes:

(A) 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 55-59.

(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation	$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 (B)		0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		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 (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

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

Line	Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1. Investments								
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0
d. Other								
2. Plant-In-Service/Depreciation Base (A)	$0	0	0	0	0	0	0	n/a
3. Less: Accumulated Depreciation	$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 (B)		0	0	0	0	0	0	0
b. Debt Component (Line 6 x debt rate x 1/12) (C)		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 (G)								
d. Property Expenses								
e. Other								
9. Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$3,364	$484	$1,498	($233,856)	$0	($245)	($228,754)
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$1,462,862	1,466,226	1,466,710	1,468,208	1,234,352	1,234,352	1,234,108	n/a
3.	Less: Accumulated Depreciation	$214,251	217,036	219,823	222,612	225,216	227,636	230,056	n/a
4.	CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,248,611	$1,249,191	$1,246,887	$1,245,596	$1,009,136	$1,006,716	$1,004,052	n/a
6.	Average Net Investment		1,248,901	1,248,039	1,246,242	1,127,366	1,007,926	1,005,384	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		7,967	7,961	7,950	7,191	6,430	6,413	$43,912
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		2,027	2,025	2,022	1,829	1,636	1,632	$11,171
8.	Investment Expenses								
	a. Depreciation (E)		2,784	2,787	2,789	2,605	2,420	2,420	$15,804
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$12,778	$12,774	$12,761	$11,626	$10,485	$10,464	$70,887

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

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		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	($228,754)
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$1,234,108	1,234,108	1,234,108	1,234,108	1,234,108	1,234,108	1,234,108	n/a
3.	Less: Accumulated Depreciation	$230,056	233,956	236,375	238,795	241,214	243,633	246,053	n/a
4.	CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,004,052	$1,000,152	$997,732	$995,313	$992,894	$990,474	$988,055	n/a
6.	Average Net Investment		1,002,102	998,942	996,523	994,103	991,684	989,265	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		6,392	6,372	6,357	6,341	6,326	6,311	82,011
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		1,626	1,621	1,617	1,613	1,609	1,605	20,863
8.	Investment Expenses								
	a. Depreciation (E)		3,900	2,419	2,419	2,419	2,419	2,419	31,801
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$11,919	$10,413	$10,393	$10,374	$10,355	$10,335	$134,676

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$352,942	352,942	352,942	352,942	352,942	352,942	352,942	n/a
3.	Less: Accumulated Depreciation	($690,552)	(690,023)	(689,494)	(688,964)	(688,435)	(687,905)	(687,376)	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,043,495	$1,042,965	$1,042,436	$1,041,907	$1,041,377	$1,040,848	$1,040,318	n/a
6.	Average Net Investment		1,043,230	1,042,701	1,042,171	1,041,642	1,041,112	1,040,583	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		6,655	6,651	6,648	6,645	6,641	6,638	$39,878
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		1,693	1,692	1,691	1,690	1,690	1,689	$10,145
8.	Investment Expenses								
	a. Depreciation (E)		529	529	529	529	529	529	$3,176
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$8,877	$8,873	$8,869	$8,864	$8,860	$8,856	$53,199

Notes:

(A) 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 55-59.

(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$352,942	352,942	352,942	352,942	352,942	352,942	352,942	n/a
3.	Less: Accumulated Depreciation	($687,376)	(686,847)	(686,317)	(685,788)	(685,258)	(684,729)	(684,200)	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,040,318	$1,039,789	$1,039,260	$1,038,730	$1,038,201	$1,037,671	$1,037,142	n/a
6.	Average Net Investment		1,040,054	1,039,524	1,038,995	1,038,465	1,037,936	1,037,407	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		6,635	6,631	6,628	6,624	6,621	6,618	79,634
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		1,688	1,687	1,686	1,685	1,684	1,684	20,259
8.	Investment Expenses								
	a. Depreciation (E)		529	529	529	529	529	529	6,353
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$8,852	$8,847	$8,843	$8,839	$8,835	$8,831	$106,246

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation	$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 (B)		0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		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 (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

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

Line	Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1. Investments								
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$1,229,528	$1,229,528
c. Retirements		$0	$0	$0	$0	$0	$0	$0
d. Other								
2. Plant-In-Service/Depreciation Base (A)	$0	0	0	0	0	0	1,229,528	n/a
3. Less: Accumulated Depreciation	$0	0	0	0	0	0	1,076	n/a
4. CWIP - Non Interest Bearing	$0	$0	$0	$0	$0	$0	$0	n/a
5. Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$1,228,452	n/a
6. Average Net Investment		0	0	0	0	0	614,226	n/a
7. Return on Average Net Investment								
a. Equity Component grossed up for taxes (B)		0	0	0	0	0	3,918	3,918
b. Debt Component (Line 6 x debt rate x 1/12) (C)		0	0	0	0	0	997	997
8. Investment Expenses								
a. Depreciation (E)		0	0	0	0	0	1,076	1,076
b. Amortization (F)								
c. Dismantlement (G)								
d. Property Expenses								
e. Other								
9. Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$5,991	$5,991

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$30,436	$150,212	$17,647	$14	$60,365	$367,059	$625,732
	c. Retirements		$0	$4,216	($34,021)	$0	$0	$0	($29,805)
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$19,346,601	19,377,037	19,527,249	19,544,896	19,544,909	19,605,274	19,972,333	n/a
3.	Less: Accumulated Depreciation	$2,881,354	2,919,793	2,962,694	2,967,405	3,006,157	3,044,964	3,084,115	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$16,465,247	$16,457,244	$16,564,555	$16,577,491	$16,538,752	$16,560,310	$16,888,217	n/a
6.	Average Net Investment		16,461,246	16,510,899	16,571,023	16,558,122	16,549,531	16,724,264	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		105,006	105,323	105,707	105,624	105,569	106,684	$633,914
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		26,713	26,794	26,891	26,871	26,857	27,140	$161,266
8.	Investment Expenses								
	a. Depreciation (E)		38,439	38,686	38,731	38,753	38,807	39,151	$232,567
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$170,158	$170,803	$171,329	$171,247	$171,233	$172,976	$1,027,746

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		($365,963)	$30,000	$6,773	$19,515	$0	$0	$316,057
	c. Retirements		($306)	$0	$0	$0	$0	$0	($30,111)
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$19,972,333	19,606,370	19,636,370	19,643,143	19,662,658	19,662,658	19,662,658	n/a
3.	Less: Accumulated Depreciation	$3,084,115	3,122,672	3,161,558	3,200,474	3,239,410	3,278,363	3,317,315	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$16,888,217	$16,483,698	$16,474,812	$16,442,669	$16,423,248	$16,384,295	$16,345,343	n/a
6.	Average Net Investment		16,685,958	16,479,255	16,458,740	16,432,958	16,403,772	16,364,819	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		106,440	105,121	104,990	104,826	104,640	104,391	1,264,321
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		27,078	26,743	26,709	26,667	26,620	26,557	321,640
8.	Investment Expenses								
	a. Depreciation (E)		38,863	38,886	38,915	38,937	38,952	38,952	466,072
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$172,380	$170,750	$170,615	$170,430	$170,212	$169,900	$2,052,033

Notes:

(A) 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 55-59.

(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$31,749,547	31,749,547	31,749,547	31,749,547	31,749,547	31,749,547	31,749,547	n/a
3.	Less: Accumulated Depreciation	$4,824,395	4,893,186	4,961,977	5,030,767	5,099,558	5,168,349	5,237,140	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$26,925,151	$26,856,361	$26,787,570	$26,718,779	$26,649,989	$26,581,198	$26,512,407	n/a
6.	Average Net Investment		26,890,756	26,821,965	26,753,175	26,684,384	26,615,593	26,546,802	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		171,536	171,097	170,658	170,220	169,781	169,342	$1,022,634
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		43,638	43,527	43,415	43,303	43,192	43,080	$260,155
8.	Investment Expenses								
	a. Depreciation (E)		68,791	68,791	68,791	68,791	68,791	68,791	$412,744
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$283,965	$283,415	$282,864	$282,314	$281,763	$281,213	$1,695,534

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$31,749,547	31,749,547	31,749,547	31,749,547	31,749,547	31,749,547	31,749,547	n/a
3.	Less: Accumulated Depreciation	$5,237,140	5,305,930	5,374,721	5,443,512	5,512,302	5,581,093	5,649,884	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$26,512,407	$26,443,616	$26,374,826	$26,306,035	$26,237,244	$26,168,454	$26,099,663	n/a
6.	Average Net Investment		26,478,012	26,409,221	26,340,430	26,271,640	26,202,849	26,134,058	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		168,903	168,464	168,026	167,587	167,148	166,709	2,029,471
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		42,969	42,857	42,745	42,634	42,522	42,410	516,292
8.	Investment Expenses								
	a. Depreciation (E)		68,791	68,791	68,791	68,791	68,791	68,791	825,488
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$280,662	$280,112	$279,562	$279,011	$278,461	$277,910	$3,371,252

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$81,901,169	81,901,169	81,901,169	81,901,169	81,901,169	81,901,169	81,901,169	n/a
3.	Less: Accumulated Depreciation	$14,251,762	14,403,579	14,555,396	14,707,212	14,859,029	15,010,845	15,162,662	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$67,649,407	$67,497,590	$67,345,774	$67,193,957	$67,042,141	$66,890,324	$66,738,507	n/a
6.	Average Net Investment		67,573,498.73	67,421,682	67,269,866	67,118,049	66,966,232	66,814,416	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		431,051.27	430,083	429,114	428,146	427,178	426,209	$2,571,781
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		109,658	109,412	109,166	108,919	108,673	108,426	$654,254
8.	Investment Expenses								
	a. Depreciation (E)		151,817	151,817	151,817	151,817	151,817	151,817	$910,900
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$692,526	$691,311	$690,097	$688,882	$687,667	$686,452	$4,136,935

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

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 2011

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$81,901,169	81,901,169	81,901,169	81,901,169	81,901,169	81,901,169	81,901,169	n/a
3.	Less: Accumulated Depreciation	$15,162,662	15,314,479	15,466,295	15,618,112	15,769,928	15,921,745	16,073,562	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$66,738,507	$66,586,691	$66,434,874	$66,283,058	$66,131,241	$65,979,424	$65,827,608	n/a
6.	Average Net Investment		66,662,599	66,510,783	66,358,966	66,207,149	66,055,333	65,903,516	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		425,241	424,272	423,304	422,335	421,367	420,398	5,108,698
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		108,180	107,934	107,687	107,441	107,195	106,948	1,299,639
8.	Investment Expenses								
	a. Depreciation (E)		151,817	151,817	151,817	151,817	151,817	151,817	1,821,799
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$685,237	$684,022	$682,808	$681,593	$680,378	$679,163	$8,230,136

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

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	($377,470)	$0	$0	($377,470)
	c. Retirements		$0	$0	$0	($377,470)	$0	$0	($377,470)
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$492,916	492,916	492,916	492,916	115,447	115,447	115,447	n/a
3.	Less: Accumulated Depreciation	$39,741	40,604	41,467	42,329	(334,608)	(334,406)	(334,204)	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$453,175	$452,312	$451,450	$450,587	$450,055	$449,853	$449,651	n/a
6.	Average Net Investment		452,744	451,881	451,018	450,321	449,954	449,752	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		2,888	2,883	2,877	2,873	2,870	2,869	$17,259
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		735	733	732	731	730	730	$4,391
8.	Investment Expenses								
	a. Depreciation (E)		863	863	863	532	202	202	$3,524
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$4,485	$4,478	$4,472	$4,136	$3,802	$3,801	$25,174

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

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	($377,470)
	c. Retirements		$345,901	$0	$0	$0	$0	$0	($31,569)
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$115,447	115,447	115,447	115,447	115,447	115,447	115,447	n/a
3.	Less: Accumulated Depreciation	($334,204)	11,899	12,101	12,303	12,505	12,707	12,909	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$449,651	$103,548	$103,346	$103,144	$102,942	$102,740	$102,538	n/a
6.	Average Net Investment		276,599	103,447	103,245	103,043	102,841	102,639	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		1,764	660	659	657	656	655	22,310
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		449	168	168	167	167	167	5,676
8.	Investment Expenses								
	a. Depreciation (E)		202	202	202	202	202	202	4,736
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$2,415	$1,030	$1,028	$1,027	$1,025	$1,023	$32,723

Notes:

(A) 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 55-59.

(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$430,045	$5,719,099	$6,805,898	$4,893,543	$4,511,190	$6,001,791	$28,361,566
	b. Clearings to Plant		$4,817,580	$419,697	($52,658,030)	$38,063,064	$15,395,820	$4,034,816	$10,072,947
	c. Retirements		$0	$6,970	$4,413	$0	$0	$0	$11,384
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$154,714,081	159,531,661	159,951,358	107,293,328	145,356,392	160,752,212	164,787,028	n/a
3.	Less: Accumulated Depreciation	$4,936,729	5,278,356	5,633,487	5,929,265	6,286,984	6,636,771	7,040,735	n/a
4.	CWIP - Non Interest Bearing	$253,353,253	249,173,523	254,892,622	261,698,521	266,592,063	271,103,253	273,076,754	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$403,130,605	$403,426,828	$409,210,493	$363,062,584	$405,661,471	$425,218,694	$430,823,047	n/a
6.	Average Net Investment		403,278,717	406,318,661	386,136,538	384,362,027	415,440,083	428,020,871	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		2,572,514	2,591,906	2,463,165	2,451,845	2,650,092	2,730,345	$15,459,866
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		654,441	659,374	626,622	623,743	674,176	694,592	$3,932,948
8.	Investment Expenses								
	a. Depreciation (E)		341,627	348,161	291,364	357,720	349,787	403,963	$2,092,623
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$3,568,582	$3,599,441	$3,381,151	$3,433,307	$3,674,055	$3,828,900	$21,485,437

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

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		$6,442,076	$11,249,603	$8,829,094	$8,601,055	$8,450,617	$18,006,551	$89,940,562
	b. Clearings to Plant		$0	$0	$0	$0	$518,275	$3,803,093	$14,394,315
	c. Retirements		$0	$0	$0	$0	$0	$0	$11,384
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$164,787,028	164,787,028	164,787,028	164,787,028	164,787,028	165,305,303	169,108,395	n/a
3.	Less: Accumulated Depreciation	$7,040,735	7,399,264	7,757,794	8,116,323	8,474,852	8,833,943	9,197,716	n/a
4.	CWIP - Non Interest Bearing	$273,076,754	279,540,224	290,789,827	299,618,921	308,219,976	316,152,318	330,355,777	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$430,823,047	$436,927,988	$447,819,062	$456,289,626	$464,532,152	$472,623,678	$490,266,457	n/a
6.	Average Net Investment		433,875,518	442,373,525	452,054,344	460,410,889	468,577,915	481,445,067	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		2,767,691	2,821,900	2,883,654	2,936,960	2,989,058	3,071,137	32,930,268
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		704,093	717,884	733,594	747,155	760,408	781,289	8,377,371
8.	Investment Expenses								
	a. Depreciation (E)		358,529	358,529	358,529	358,529	359,091	363,772	4,249,603
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$3,830,314	$3,898,313	$3,975,777	$4,042,645	$4,108,557	$4,216,199	$45,557,242

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		($21,691)	$199,294	$204,880	$231,090	$242,381	($320,135)	$535,818
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$105,905,052	105,883,361	106,082,655	106,287,535	106,518,624	106,761,006	106,440,871	n/a
3.	Less: Accumulated Depreciation	$1,882,324	2,111,762	2,341,392	2,571,459	2,801,999	3,033,052	3,264,021	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$104,022,728	$103,771,600	$103,741,263	$103,716,075	$103,716,625	$103,727,954	$103,176,850	n/a
6.	Average Net Investment		103,897,164	103,756,432	103,728,669	103,716,350	103,722,289	103,452,402	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		662,760	661,862	661,685	661,606	661,644	659,923	$3,969,481
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		168,604	168,376	168,331	168,311	168,321	167,883	$1,009,825
8.	Investment Expenses								
	a. Depreciation (E)		229,437	229,630	230,068	230,540	231,053	230,969	$1,381,697
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,060,802	$1,059,868	$1,060,084	$1,060,457	$1,061,018	$1,058,774	$6,361,002

Notes:

(A) 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 55-59.

(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$145,730	$153,882	$183,966	$195,929	$84,515	$60,511	$1,360,351
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$106,440,871	106,586,601	106,740,483	106,924,449	107,120,378	107,204,893	107,265,404	n/a
3.	Less: Accumulated Depreciation	$3,264,021	3,494,801	3,725,905	3,957,375	4,189,257	4,421,443	4,653,786	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$103,176,850	$103,091,800	$103,014,578	$102,967,074	$102,931,121	$102,783,450	$102,611,618	n/a
6.	Average Net Investment		103,134,325	103,053,189	102,990,826	102,949,097	102,857,285	102,697,534	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		657,894	657,376	656,978	656,712	656,126	655,107	7,909,675
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		167,366	167,235	167,134	167,066	166,917	166,658	2,012,200
8.	Investment Expenses								
	a. Depreciation (E)		230,780	231,104	231,470	231,882	232,186	232,343	2,771,462
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,056,040	$1,055,715	$1,055,582	$1,055,660	$1,055,229	$1,054,108	$12,693,336

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

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

Line	Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1. Investments								
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$147,578	$147,578
c. Retirements		$0	$0	$0	$0	$0	$0	$0
d. Other								
2. Plant-In-Service/Depreciation Base (A)	$235,391	235,391	235,391	235,391	235,391	235,391	382,969	n/a
3. Less: Accumulated Depreciation	$8,710	9,122	9,534	9,946	10,358	10,770	11,311	n/a
4. CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5. Net Investment (Lines 2 - 3 + 4)	$226,681	$226,269	$225,857	$225,445	$225,033	$224,621	$371,658	n/a
6. Average Net Investment		226,475	226,063	225,651	225,239	224,827	298,140	n/a
7. Return on Average Net Investment								
a. Equity Component grossed up for taxes (B)		1,445	1,442	1,439	1,437	1,434	1,902	$9,099
b. Debt Component (Line 6 x debt rate x 1/12) (C)		368	367	366	366	365	484	$2,315
8. Investment Expenses								
a. Depreciation (E)		412	412	412	412	412	541	$2,601
b. Amortization (F)								
c. Dismantlement (G)								
d. Property Expenses								
e. Other								
9. Total System Recoverable Expenses (Lines 7 & 8)		$2,224	$2,221	$2,218	$2,214	$2,211	$2,927	$14,015

Notes:

(A) 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 55-59.

(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

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

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		($147,578)	$0	$0	$0	$0	$0	$0
	c. Retirements		($129)	$0	$0	$0	$0	$0	($129)
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$382,969	235,391	235,391	235,391	235,391	235,391	235,391	n/a
3.	Less: Accumulated Depreciation	$11,311	11,594	12,006	12,418	12,830	13,242	13,654	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$371,658	$223,797	$223,386	$222,974	$222,562	$222,150	$221,738	n/a
6.	Average Net Investment		297,728	223,591	223,180	222,768	222,356	221,944	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		1,899	1,426	1,424	1,421	1,418	1,416	18,103
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		483	363	362	362	361	360	4,605
8.	Investment Expenses								
	a. Depreciation (E)		412	412	412	412	412	412	5,072
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$2,794	$2,201	$2,198	$2,194	$2,191	$2,188	$27,781

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Low Level Rad Waste - LLW (Project No. 36)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$5,465,817	$345,053	$5,810,871
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$0	0	0	0	0	5,465,817	5,810,871	n/a
3.	Less: Accumulated Depreciation	$0	0	0	0	0	4,099	12,557	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	$5,461,718	$5,798,314	n/a
6.	Average Net Investment		0	0	0	0	2,730,859	5,630,016	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		0	0	0	0	17,420	35,914	$53,334
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		0	0	0	0	4,432	9,136	$13,568
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	4,099	8,458	$12,557
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$25,951	$53,508	$79,459

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

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 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Low Level Rad Waste - LLW (Project No. 36)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$1,014,698	$76,273	$8,000	$7,000	$5,000	$5,000	$6,926,842
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$5,810,871	6,825,569	6,901,842	6,909,842	6,916,842	6,921,842	6,926,842	n/a
3.	Less: Accumulated Depreciation	$12,557	22,034	32,330	42,689	53,059	63,438	73,824	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$5,798,314	$6,803,534	$6,869,512	$6,867,153	$6,863,783	$6,858,404	$6,853,017	n/a
6.	Average Net Investment		6,300,924	6,836,523	6,868,332	6,865,468	6,861,093	6,855,711	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		40,194	43,610	43,813	43,795	43,767	43,733	312,245
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		10,225	11,094	11,146	11,141	11,134	11,125	79,434
8.	Investment Expenses								
	a. Depreciation (E)		9,477	10,296	10,359	10,370	10,379	10,387	73,824
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$59,896	$65,000	$65,318	$65,306	$65,280	$65,245	$465,504

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Desoto Next Generation Solar Energy Center (Project No. 37)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
a.	Expenditures/Additions		$164,005	$125,045	$263,198	$211,038	$0	$0	$763,285
b.	Clearings to Plant		$132,320	$10,675	$13,719	$1,549	$827,101	$3,937	$989,301
c.	Retirements		$0	$0	$0	$0	$0	$0	$0
d.	Other								
2.	Plant-In-Service/Depreciation Base (A)	$151,221,418	151,353,738	151,364,413	151,378,132	151,379,681	152,206,782	152,210,719	n/a
3.	Less: Accumulated Depreciation & Dismantlement	$5,939,454	6,359,233	6,779,208	7,199,283	7,619,317	8,040,478	8,462,880	n/a
4.	CWIP - Non Interest Bearing	$20,831	184,836	309,881	573,079	782,567	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$145,302,795	$145,179,342	$144,895,086	$144,751,928	$144,542,932	$144,166,304	$143,747,839	n/a
6.	Average Net Investment		145,241,069	145,037,214	144,823,507	144,647,430	144,354,618	143,957,072	n/a
a.	Average ITC Balance		42,173,913	42,051,847	41,929,781	41,807,715	41,685,649	41,563,583	
7.	Return on Average Net Investment (B & C)								
a.	Equity Component grossed up for taxes (B)		999,615	998,103	996,528	995,193	993,113	990,366	$5,972,917
b.	Debt Component (Line 6 x debt rate x 1/12) (C)		244,929	244,572	244,198	243,886	243,384	242,712	$1,463,680
8.	Investment Expenses								
a.	Depreciation (E)		413,720	413,916	414,016	413,975	415,102	416,343	$2,487,072
b.	Amortization (F)								
c.	Dismantlement (G)		6,059	6,059	6,059	6,059	6,059	6,059	$36,354
d.	Property Expenses								
e.	Amortization ITC Solar		(160,395)	(160,395)	(160,395)	(160,395)	(160,395)	(160,395)	(962,370)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,503,927	$1,502,255	$1,500,406	$1,498,717	$1,497,263	$1,495,084	$8,997,653

Notes:

(A) 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 55-59.

(B) & (C) For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity.

Debt Component: Return of 1.9473% reflects a 10% ROE. Per FPSC Order No PSC-10-0153-FOF-EI.

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.98% reflects a 10% return on equity.

Debt Component: Return of 2.21% based on the 10% ROE. Per FPSC Order PSC 10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

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 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Desoto Next Generation Solar Energy Center (Project No. 37)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
a.	Expenditures/Additions		$0	$100,000	$175,000	$250,000	$150,000	$144,672	$1,582,957
b.	Clearings to Plant		$0	$0	$0	$0	$0	$819,672	$1,808,973
c.	Retirements		$0	$0	$0	$0	$0	$0	$0
d.	Other								
2.	Plant-In-Service/Depreciation Base (A)	$152,210,719	152,210,719	152,210,719	152,210,719	152,210,719	152,210,719	153,030,391	n/a
3.	Less: Accumulated Depreciation & Dismantlement	$8,462,880	8,885,294	9,307,708	9,730,121	10,152,535	10,574,949	10,998,580	n/a
4.	CWIP - Non Interest Bearing	$0	0	100,000	275,000	525,000	675,000	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$143,747,839	$143,325,426	$143,003,012	$142,755,598	$142,583,184	$142,310,770	$142,031,811	n/a
6.	Average Net Investment	143,957,072	143,536,632	143,164,219	142,879,305	142,669,391	142,446,977	142,171,291	n/a
a.	Average ITC Balance	41,563,583	41,441,517	41,319,451	41,197,385	41,075,319	40,953,253	40,831,187	
7.	Return on Average Net Investment								
a.	Equity Component grossed up for taxes (B)		987,472	984,885	982,856	981,305	979,675	977,704	11,866,814
b.	Debt Component (Line 6 x debt rate x 1/12) (C)		242,003	241,372	240,883	240,515	240,128	239,654	2,908,233
8.	Investment Expenses								
a.	Depreciation (E)		416,355	416,355	416,355	416,355	416,355	417,572	4,986,418
b.	Amortization (F)								
c.	Dismantlement (G)		6,059	6,059	6,059	6,059	6,059	6,059	$72,708
d.	Property Expenses								
e.	Amortization ITC Solar		(160,395)	(160,395)	(160,395)	(160,395)	(160,395)	(160,395)	(1,924,740)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,491,494	$1,488,276	$1,485,757	$1,483,839	$1,481,821	$1,480,594	$17,909,434

Notes:

(A) 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 55-59.

(B) & (C) For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity.

Debt Component: Return of 1.9473% reflects a 10% ROE. Per FPSC Order No PSC-10-0153-FOF-EI.

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.98% reflects a 10% return on equity.

Debt Component: Return of 2.21% based on the 10% ROE. Per FPSC Order PSC 10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Space Coast Next Generation Solar Energy Center (Project No. 38)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
a.	Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
b.	Clearings to Plant		$1,929	($283)	$33,216	$3,301	($2)	$903	$39,065
c.	Retirements		$0	$0	$0	$0	$0	$0	$0
d.	Other								
2.	Plant-In-Service/Depreciation Base (A)	$70,583,766	70,585,695	70,585,412	70,618,629	70,621,929	70,621,928	70,622,831	n/a
3.	Less: Accumulated Depreciation & Dismantlement	$1,678,307	1,875,804	2,073,303	2,270,859	2,468,508	2,666,155	2,863,785	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$68,905,459	$68,709,891	$68,512,110	$68,347,770	$68,153,422	$67,955,773	$67,759,047	n/a
6.	Average Net Investment		68,807,675	68,611,000	68,429,940	68,250,596	68,054,597	67,857,410	n/a
a.	Average ITC Balance		17,967,207	17,916,018	17,864,829	17,813,640	17,762,451	17,711,262	
7.	Return on Average Net Investment								
a.	Equity Component grossed up for taxes (B)		470,076	468,733	467,489	466,256	464,917	463,571	$2,801,041
b.	Debt Component (Line 6 x debt rate x 1/12) (C)		115,594	115,264	114,959	114,656	114,327	113,996	$688,796
8.	Investment Expenses								
a.	Depreciation (E)		194,585	194,587	194,644	194,737	194,735	194,718	$1,168,005
b.	Amortization (F)								
c.	Dismantlement (G)		2,912	2,912	2,912	2,912	2,912	2,912	$17,472
d.	Property Expenses								
e.	Amortization ITC Solar		(67,263)	(67,263)	(67,263)	(67,263)	(67,263)	(67,263)	(403,578)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$715,904	$714,232	$712,740	$711,299	$709,628	$707,933	$4,271,737

Notes:

(A) 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 55-59.

(B) & (C) For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity.

Debt Component: Return of 1.9473% reflects a 10% ROE. Per FPSC Order No PSC-10-0153-FOF-EI.

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.98% reflects a 10% return on equity.

Debt Component: Return of 2.21% based on the 10% ROE. Per FPSC Order PSC 10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Space Coast Next Generation Solar Energy Center (Project No. 38)
(in Dollars)

Line			Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments									
	a.	Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b.	Clearings to Plant		$7,210	$0	$0	$0	$0	$0	$46,275
	c.	Retirements		$0	$0	$0	$0	$0	$0	$0
	d.	Other								
2.	Plant-In-Service/Depreciation Base (A)		$70,622,831	70,630,041	70,630,041	70,630,041	70,630,041	70,630,041	70,630,041	n/a
3.	Less: Accumulated Depreciation & Dismantlement		$2,863,785	3,061,425	3,259,076	3,456,726	3,654,377	3,852,027	4,049,678	n/a
4.	CWIP - Non Interest Bearing		$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)		$67,759,047	$67,568,616	$67,370,966	$67,173,315	$66,975,665	$66,778,014	$66,580,364	n/a
6.	Average Net Investment			67,663,831	67,469,791	67,272,140	67,074,490	66,876,839	66,679,189	n/a
	a.	Average ITC Balance	$17,711,262	17,660,073	17,608,884	17,557,695	17,506,506	17,455,317	17,404,128	
7.	Return on Average Net Investment									
	a.	Equity Component grossed up for taxes (B)		462,247	460,920	459,571	458,221	456,872	455,522	5,554,395
	b.	Debt Component (Line 6 x debt rate x 1/12) (C)		113,671	113,345	113,013	112,681	112,349	112,017	1,365,870
8.	Investment Expenses									
	a.	Depreciation (E)		194,729	194,739	194,739	194,739	194,739	194,739	2,336,427
	b.	Amortization (F)								
	c.	Dismantlement (G)		2,912	2,912	2,912	2,912	2,912	2,912	34,944
	d.	Property Expenses								
	e.	Amortization ITC Solar		(67,263)	(67,263)	(67,263)	(67,263)	(67,263)	(67,263)	(807,156)
9.	Total System Recoverable Expenses (Lines 7 & 8)			$706,295	$704,652	$702,971	$701,289	$699,608	$697,926	$8,484,479

Notes:

(A) 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 55-59.

(B) & (C) For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity.

Debt Component: Return of 1.9473% reflects a 10% ROE. Per FPSC Order No PSC-10-0153-FOF-EI.

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.98% reflects a 10% return on equity.

Debt Component: Return of 2.21% based on the 10% ROE. Per FPSC Order PSC 10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Martin Next Generation Solar Energy Center (Project No. 39)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$72,288	$16,250	$33,500	$47,708	$4,656	$7,243	$181,645
	b. Clearings to Plant		$2,059,295	$687,522	$1,310,311	$315,220	$1,307,060	$311,605	$5,991,013
	c. Retirements		$0	$759	$0	$0	$0	$0	$759
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$392,125,689	394,184,983	394,872,505	396,182,816	396,498,036	397,805,096	398,116,702	n/a
3.	Less: Accumulated Depreciation & Dismantlement	$858,379	1,968,380	3,082,905	4,200,130	5,320,430	6,442,994	7,567,817	n/a
4.	CWIP - Non Interest Bearing	$394,809	467,097	483,348	166,902	214,610	171,974	179,217	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$391,662,119	$392,683,701	$392,272,947	$392,149,588	$391,392,216	$391,534,076	$390,728,102	n/a
6.	Average Net Investment		392,172,910	392,478,324	392,211,268	391,770,902	391,463,146	391,131,089	n/a
	a. Average ITC Balance		123,351,385	123,007,587	122,663,789	122,319,991	121,976,193	121,632,395	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		2,715,540	2,716,892	2,714,592	2,711,187	2,708,628	2,705,914	$16,272,753
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		663,420	663,840	663,332	662,542	661,967	661,353	$3,976,453
8.	Investment Expenses								
	a. Depreciation (E)		1,081,154	1,084,919	1,088,377	1,091,454	1,093,717	1,095,976	$6,535,598
	b. Amortization (F)								
	c. Dismantlement (G)		28,847	28,847	28,847	28,847	28,847	28,847	$173,082
	d. Property Expenses								
	e. Amortization ITC Solar		(451,751)	(451,751)	(451,751)	(451,751)	(451,751)	(451,751)	($2,710,506)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$4,037,210	$4,042,747	$4,043,397	$4,042,278	$4,041,408	$4,040,339	$24,247,380

Notes:

(A) 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 55-59.

(B) & (C) For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity.

Debt Component: Return of 1.9473% reflects a 10% ROE. Per FPSC Order No PSC-10-0153-FOF-EI.

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.98% reflects a 10% return on equity.

Debt Component: Return of 2.21% based on the 10% ROE. Per FPSC Order PSC 10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

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 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Martin Next Generation Solar Energy Center (Project No. 39)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$805,000	$425,000	$350,000	$560,000	$50,000	$50,000	$2,421,645
	b. Clearings to Plant		$675,000	$300,000	$200,000	$410,000	$0	$884,217	$8,460,230
	c. Retirements		$0	$0	$0	$0	$0	$0	$759
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$398,116,702	398,791,702	399,091,702	399,291,702	399,701,702	399,701,702	400,585,919	n/a
3.	Less: Accumulated Depreciation & Dismantlement	$7,567,817	8,693,997	9,821,517	10,949,725	12,078,772	13,208,382	14,339,208	n/a
4.	CWIP - Non Interest Bearing	$179,217	309,217	434,217	584,217	734,217	784,217	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$390,728,102	$390,406,922	$389,704,402	$388,926,194	$388,357,147	$387,277,537	$386,246,711	n/a
6.	Average Net Investment	391,131,089	390,567,512	390,055,662	389,315,298	388,641,670	387,817,342	386,762,124	n/a
	a. Average ITC Balance	$121,632,395	121,288,597	120,944,799	120,601,001	120,257,203	119,913,405	119,569,607	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		2,701,722	2,697,861	2,692,542	2,687,649	2,681,795	2,674,467	32,408,791
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		660,363	659,457	658,180	657,012	655,599	653,811	7,920,876
8.	Investment Expenses								
	a. Depreciation (E)		1,097,333	1,098,673	1,099,361	1,100,200	1,100,763	1,101,979	13,133,907
	b. Amortization (F)								
	c. Dismantlement (G)		28,847	28,847	28,847	28,847	28,847	28,847	346,164
	d. Property Expenses								
	e. Amortization ITC Solar		(451,751)	(451,751)	(451,751)	(451,751)	(451,751)	(451,751)	(5,421,012)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$4,036,514	$4,033,088	$4,027,180	$4,021,957	$4,015,253	$4,007,354	$48,388,725

Notes:

(A) 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 55-59.

(B) & (C) For solar projects the return on investment calculation is comprised of two parts:

Average Net Investment

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity.

Debt Component: Return of 1.9473% reflects a 10% ROE. Per FPSC Order No PSC-10-0153-FOF-EI.

Average Unamortized ITC Balance:

Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.98% reflects a 10% return on equity.

Debt Component: Return of 2.21% based on the 10% ROE. Per FPSC Order PSC 10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Temporary Heating System (Project No. 41)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$203,250	$194,579	$35,286	$206	$3,003	($3,025)	$433,299
	c. Retirements		$2,061	$8,490	$10,609	$0	$0	$0	$21,160
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$7,412,851	7,516,101	7,810,680	7,845,966	7,846,172	7,849,175	7,846,151	n/a
3.	Less: Accumulated Depreciation	$44,776	54,071	70,051	88,401	96,144	103,890	111,628	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$7,368,075	$7,562,030	$7,740,629	$7,757,565	$7,750,028	$7,745,285	$7,734,523	n/a
6.	Average Net Investment		7,465,053	7,651,330	7,749,097	7,753,796	7,747,656	7,739,904	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		47,620	48,808	49,431	49,461	49,422	49,373	$294,115
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		12,114	12,417	12,575	12,583	12,573	12,560	$74,822
8.	Investment Expenses								
	a. Depreciation (E)		7,235	7,489	7,742	7,743	7,746	7,737	$45,692
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$66,968	$68,714	$69,749	$69,787	$69,741	$69,670	$414,630

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Manatee Temporary Heating System (Project No. 41)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$977,577	$100,000	$46,994	$1,557,870
	c. Retirements		$0	$0	$0	$0	$0	$0	$21,160
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$7,846,151	7,846,151	7,846,151	7,846,151	8,823,728	8,923,728	8,970,722	n/a
3.	Less: Accumulated Depreciation	$111,628	119,353	127,079	134,805	142,816	151,141	159,509	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$7,734,523	$7,726,797	$7,719,071	$7,711,346	$8,680,912	$8,772,586	$8,811,212	n/a
6.	Average Net Investment		7,730,660	7,722,934	7,715,208	8,196,129	8,726,749	8,791,899	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		49,314	49,265	49,215	52,283	55,668	56,084	605,944
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		12,545	12,533	12,520	13,301	14,162	14,267	154,150
8.	Investment Expenses								
	a. Depreciation (E)		7,726	7,726	7,726	8,011	8,325	8,368	93,574
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$69,585	$69,523	$69,461	$73,595	$78,155	$78,719	$853,668

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: PTN Cooling Canal Monitoring System (Project No. 42)
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		0	0	0	0	0	0	$0
	b. Clearings to Plant		$115,328	$2,766	($117,518)	($11,364)	$0	$0	($10,788)
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$3,593,541	3,708,869	3,711,634	3,594,116	3,582,753	3,582,753	3,582,753	n/a
3.	Less: Accumulated Depreciation	$2,695	8,172	13,737	19,217	24,599	29,973	35,348	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$3,590,846	$3,700,697	$3,697,897	$3,574,900	$3,558,154	$3,552,779	$3,547,405	n/a
6.	Average Net Investment		3,645,771	3,699,297	3,636,398	3,566,527	3,555,467	3,550,092	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		23,256	23,598	23,197	22,751	22,680	22,646	$138,128
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		5,916	6,003	5,901	5,788	5,770	5,761	$35,139
8.	Investment Expenses								
	a. Depreciation (E)		5,477	5,565	5,479	5,383	5,374	5,374	$32,652
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$34,650	$35,166	$34,577	$33,921	$33,824	$33,781	$205,920

Notes:

(A) 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 55-59.

(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.

(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: PTN Cooling Canal Monitoring System (Project No. 42)
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	($10,788)
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$3,582,753	3,582,753	3,582,753	3,582,753	3,582,753	3,582,753	3,582,753	n/a
3.	Less: Accumulated Depreciation	$35,348	40,722	46,096	51,470	56,844	62,218	67,592	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$3,547,405	$3,542,031	$3,536,657	$3,531,283	$3,525,909	$3,520,535	$3,515,161	n/a
6.	Average Net Investment		3,544,718	3,539,344	3,533,970	3,528,596	3,523,222	3,517,848	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		22,612	22,577	22,543	22,509	22,475	22,440	273,284
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		5,752	5,744	5,735	5,726	5,717	5,709	69,523
8.	Investment Expenses								
	a. Depreciation (E)		5,374	5,374	5,374	5,374	5,374	5,374	64,897
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$33,738	$33,695	$33,652	$33,609	$33,566	$33,523	$407,704

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Martin Plant Barley Barber Swamp Iron Mitigation Project (Project No. 44)
(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								
2.	Plant-In-Service/Depreciation Base (A)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation	$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 (B)		0	0	0	0	0	0	$0
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		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 (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Martin Plant Barley Barber Swamp Iron Mitigation Project (Project No. 44)
(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		$147,578	$0	$0	$0	$0	$0	$147,578
	c. Retirements		$129	$0	$0	$0	$0	$0	$129
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$0	147,578	147,578	147,578	147,578	147,578	147,578	n/a
3.	Less: Accumulated Depreciation	$0	387	646	904	1,162	1,420	1,679	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$0	$147,191	$146,933	$146,674	$146,416	$146,158	$145,899	n/a
6.	Average Net Investment		73,595	147,062	146,803	146,545	146,287	146,029	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		469	936	936	935	933	932	5,144
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		119	239	238	238	237	237	1,308
8.	Investment Expenses								
	a. Depreciation (E)		258	258	258	258	258	258	1,550
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$847	$1,435	$1,433	$1,431	$1,429	$1,427	$8,002

Notes:

(A) 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 55-59.
(B) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.
(C) Debt Component: 1.9473% reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8E, pages 55-59.
(F) Applicable amortization period(s). See Form 42-8E, pages 55-59.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39).

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2011

Return on Capital Investments, Depreciation and Taxes
Deferred Gain on Sales of Emission Allowances
(in Dollars)

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1	Working Capital Dr (Cr)								
a	158.100 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0	
b	158.200 Allowances Withheld	0	0	0	0	0	0	0	
c	182.300 Other Regulatory Assets-Losses	0	0	0	0	0	0	0	
d	254.900 Other Regulatory Liabilities-Gains	(2,054,468)	(2,033,042)	(2,011,616)	(1,990,190)	(1,968,764)	(1,950,542)	(1,929,071)	
2	Total Working Capital	($2,054,468)	($2,033,042)	($2,011,616)	($1,990,190)	($1,968,764)	($1,950,542)	($1,929,071)	
3	Average Net Working Capital Balance		(2,043,755)	(2,022,329)	(2,000,903)	(1,979,477)	(1,959,653)	(1,939,807)	
4	Return on Average Net Working Capital Balance								
a	Equity Component grossed up for taxes (A)		(13,037)	(12,900)	(12,764)	(12,627)	(12,501)	(12,374)	
b	Debt Component (Line 6 x 1.9473% x 1/12)		(3,317)	(3,282)	(3,247)	(3,212)	(3,180)	(3,148)	
5	Total Return Component		($16,354)	($16,182)	($16,011)	($15,839)	($15,681)	($15,522)	($95,589) (D)
6	Expense Dr (Cr)								
a	411.800 Gains from Dispositions of Allowances		(21,426)	(21,426)	(21,426)	(21,426)	(23,500)	(38,921)	
b	411.900 Losses from Dispositions of Allowances		0	0	0	0	0	0	
c	509.000 Allowance Expense		0	0	0	0	0	0	
7	Net Expense (Lines 6a+6b+6c)		($21,426)	($21,426)	($21,426)	($21,426)	($23,500)	($38,921)	($148,125) (E)
8	Total System Recoverable Expenses (Lines 5+7)		(37,780)	(37,608)	(37,437)	(37,265)	(39,181)	(54,443)	
a	Recoverable Costs Allocated to Energy		(37,780)	(37,608)	(37,437)	(37,265)	(39,181)	(54,443)	
b	Recoverable Costs Allocated to Demand		0	0	0	0	0	0	
9	Energy Jurisdictional Factor		98.02710%	98.02710%	98.02710%	98.02710%	98.02710%	98.02710%	
10	Demand Jurisdictional Factor		98.03105%	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%	
11	Retail Energy-Related Recoverable Costs (B)		(37,034)	(36,866)	(36,698)	(36,530)	(38,408)	(53,368)	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($37,034)	($36,866)	($36,698)	($36,530)	($38,408)	($53,368)	

Notes:

(A) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule
(E) Line 7 is reported on O&M Schedule

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 2011

Return on Capital Investments, Depreciation and Taxes
Deferred Gain on Sales of Emission Allowances
(in Dollars)

Line		Beginning of Period Amount	July Estimated	August Estimated	September Estimated	October Estimated	November Estimated	December Estimated	Twelve Month Amount
1	Working Capital Dr (Cr)								
a	158.100 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0	
b	158.200 Allowances Withheld	$0	0	0	0	0	0	0	
c	182.300 Other Regulatory Assets-Losses	$0	0	0	0	0	0	0	
d	254.900 Other Regulatory Liabilities-Gains	($1,929,071)	(1,907,174)	(1,885,278)	(1,863,383)	(1,841,487)	(1,819,591)	(1,797,695)	
2	Total Working Capital	($1,929,071)	($1,907,174)	($1,885,278)	($1,863,383)	($1,841,487)	($1,819,591)	($1,797,695)	
3	Average Net Working Capital Balance		(1,918,123)	(1,896,226)	(1,874,330)	(1,852,435)	(1,830,539)	(1,808,643)	
4	Return on Average Net Working Capital Balance								
a	Equity Component grossed up for taxes (A)		(12,236)	(12,096)	(11,956)	(11,817)	(11,677)	(11,537)	
b	Debt Component (Line 6 x 1.9473% x 1/12)		(3,113)	(3,077)	(3,042)	(3,006)	(2,971)	(2,935)	
5	Total Return Component		($15,348)	($15,173)	($14,998)	($14,823)	($14,648)	($14,472)	($185,051) (D)
6	Expense Dr (Cr)								
a	411.800 Gains from Dispositions of Allowances		(21,896)	(21,896)	(21,896)	(21,896)	(21,896)	(21,896)	
b	411.900 Losses from Dispositions of Allowances		0	0	0	0	0	0	
c	509.000 Allowance Expense		0	0	0	0	0	0	
7	Net Expense (Lines 6a+6b+6c)		($21,896)	($21,896)	($21,896)	($21,896)	($21,896)	($21,896)	($279,501) (E)
8	Total System Recoverable Expenses (Lines 5+7)		(37,244)	(37,069)	(36,894)	(36,719)	(36,544)	(36,368)	
a	Recoverable Costs Allocated to Energy		(37,244)	(37,069)	(36,894)	(36,719)	(36,544)	(36,368)	
b	Recoverable Costs Allocated to Demand		0	0	0	0	0	0	
9	Energy Jurisdictional Factor		98.02710%	98.02710%	98.02710%	98.02710%	98.02710%	98.02710%	
10	Demand Jurisdictional Factor		98.03105%	98.03105%	98.03105%	98.03105%	98.03105%	98.03105%	
11	Retail Energy-Related Recoverable Costs (B)		(36,510)	(36,338)	(36,166)	(35,994)	(35,823)	(35,651)	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	
	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 55-59.								
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($36,510)	($36,338)	($36,166)	($35,994)	($35,823)	($35,651)	

Notes:

(A) Equity Component: Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 4.7019% reflects a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI.

(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule
(E) Line 7 is reported on O&M Schedule

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
2011 Annual Capital Depreciation Schedule

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Actual Balance December 2010	Estimated Balance December 2011
02 - Low NOX Burner Technology						
	02 - Steam Generation Plant	PtEverglades U1	31200	2.30%	2,689,232.57	2,689,232.57
	02 - Steam Generation Plant	PtEverglades U2	31200	2.30%	2,368,972.27	2,368,972.27
	02 - Steam Generation Plant	TurkeyPt U1	31200	2.50%	2,563,376.41	2,563,376.41
	02 - Steam Generation Plant	TurkeyPt U2	31200	2.50%	2,275,221.65	2,275,221.65
02 - Low NOX Burner Technology Total					**9,896,802.90**	**9,896,802.90**
03 - Continuous Emission Monitoring						
	02 - Steam Generation Plant	Cutler Comm	31100	1.70%	64,883.87	64,883.87
	02 - Steam Generation Plant	Cutler Comm	31200	2.20%	36,276.52	36,276.52
	02 - Steam Generation Plant	Cutler U5	31200	2.20%	310,454.41	310,454.41
	02 - Steam Generation Plant	Cutler U6	31200	2.20%	311,861.95	311,861.95
	02 - Steam Generation Plant	Manatee Comm	31200	2.60%	31,859.00	31,859.00
	02 - Steam Generation Plant	Manatee U1	31100	2.10%	56,430.25	56,430.25
	02 - Steam Generation Plant	Manatee U1	31200	2.60%	477,896.88	477,896.88
	02 - Steam Generation Plant	Manatee U2	31100	2.10%	56,332.75	56,332.75
	02 - Steam Generation Plant	Manatee U2	31200	2.60%	508,552.43	508,552.43
	02 - Steam Generation Plant	Martin Comm	31200	2.60%	31,631.74	31,631.74
	02 - Steam Generation Plant	Martin U1	31100	2.10%	36,810.86	36,810.86
	02 - Steam Generation Plant	Martin U1	31200	2.60%	529,318.55	529,318.55
	02 - Steam Generation Plant	Martin U2	31100	2.10%	36,845.37	36,845.37
	02 - Steam Generation Plant	Martin U2	31200	2.60%	525,201.70	525,201.70
	02 - Steam Generation Plant	PtEverglades Comm	31100	1.90%	127,911.34	127,911.34
	02 - Steam Generation Plant	PtEverglades Comm	31200	2.30%	67,787.69	67,787.69
	02 - Steam Generation Plant	PtEverglades U1	31200	2.30%	458,060.74	458,060.74
	02 - Steam Generation Plant	PtEverglades U2	31200	2.30%	480,321.84	480,321.84
	02 - Steam Generation Plant	PtEverglades U3	31200	2.30%	507,658.33	507,658.33
	02 - Steam Generation Plant	PtEverglades U4	31200	2.30%	517,303.41	517,303.41
	02 - Steam Generation Plant	Sanford U3	31100	1.90%	54,282.08	54,282.08
	02 - Steam Generation Plant	Sanford U3	31200	2.40%	434,357.43	434,357.43
	02 - Steam Generation Plant	Scherer U4	31200	2.60%	515,653.32	515,653.32
	02 - Steam Generation Plant	SJRPP - Comm	31100	2.10%	43,193.33	43,193.33
	02 - Steam Generation Plant	SJRPP U1	31200	2.60%	779.50	779.50
	02 - Steam Generation Plant	SJRPP U2	31200	2.60%	779.51	779.51
	02 - Steam Generation Plant	TurkeyPt Comm Fsil	31100	2.10%	59,056.19	59,056.19
	02 - Steam Generation Plant	TurkeyPt Comm Fsil	31200	2.50%	37,954.50	37,954.50
	02 - Steam Generation Plant	TurkeyPt U1	31200	2.50%	545,584.31	545,584.31
	02 - Steam Generation Plant	TurkeyPt U2	31200	2.50%	504,688.53	504,688.53
	05 - Other Generation Plant	FtLauderdale Comm	34100	3.50%	58,859.79	58,859.79
	05 - Other Generation Plant	FtLauderdale Comm	34500	3.40%	34,502.21	34,502.21
	05 - Other Generation Plant	FtLauderdale U4	34300	4.30%	462,254.20	462,254.20
	05 - Other Generation Plant	FtLauderdale U5	34300	4.20%	473,359.99	473,359.99
	05 - Other Generation Plant	FtMyers U2 CC	34300	4.20%	23,619.18	23,619.18
	05 - Other Generation Plant	FtMyers U3 CC	34300	5.20%	2,282.97	2,282.97
	05 - Other Generation Plant	Martin U3	34300	4.20%	416,872.29	416,872.29
	05 - Other Generation Plant	Martin U4	34300	4.20%	409,474.06	409,474.06
	05 - Other Generation Plant	Martin U8	34300	4.30%	13,693.21	13,693.21
	05 - Other Generation Plant	Putnam Comm	34100	2.60%	82,857.82	82,857.82
	05 - Other Generation Plant	Putnam Comm	34300	4.20%	3,138.97	3,138.97
	05 - Other Generation Plant	Putnam U1	34300	4.00%	346,616.08	346,616.08
	05 - Other Generation Plant	Putnam U2	34300	3.30%	380,355.07	380,355.07
	05 - Other Generation Plant	Sanford U4	34300	4.80%	98,339.95	98,339.95
	05 - Other Generation Plant	Sanford U5	34300	4.20%	56,521.05	56,521.05
03 - Continuous Emission Monitoring Total					**10,232,475.17**	**10,232,475.17**
04 - Clean Closure Equivalency Demonstration						
	02 - Steam Generation Plant	PtEverglades Comm	31100	1.90%	19,812.30	19,812.30
	02 - Steam Generation Plant	TurkeyPt Comm Fsil	31100	2.10%	21,799.28	21,799.28
04 - Clean Closure Equivalency Demonstration Total					**41,611.58**	**41,611.58**

Florida Power & Light Company
Environmental Cost Recovery Clause
2011 Annual Capital Depreciation Schedule

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Actual Balance December 2010	Estimated Balance December 2011
05 - Maintenance of Above Ground Fuel Tanks						
	02 - Steam Generation Plant	Manatee Comm	31100	2.10%	3,111,263.35	3,111,263.35
	02 - Steam Generation Plant	Manatee Comm	31200	2.60%	174,543.23	174,543.23
	02 - Steam Generation Plant	Manatee U1	31100	2.10%	0.00	5,500.00
	02 - Steam Generation Plant	Manatee U1	31200	2.60%	104,845.35	104,845.35
	02 - Steam Generation Plant	Manatee U2	31100	2.10%	0.00	5,500.00
	02 - Steam Generation Plant	Manatee U2	31200	2.60%	127,429.19	127,429.19
	02 - Steam Generation Plant	Martin Comm	31100	2.10%	1,110,450.32	1,110,450.32
	02 - Steam Generation Plant	Martin Comm	31200	2.60%	94,329.22	94,329.22
	02 - Steam Generation Plant	Martin U1	31100	2.10%	176,338.83	176,338.83
	02 - Steam Generation Plant	PtEverglades Comm	31100	1.90%	1,132,078.22	1,132,078.22
	02 - Steam Generation Plant	Sanford U3	31100	1.90%	796,754.11	796,754.11
	02 - Steam Generation Plant	SJRPP - Comm	31100	2.10%	42,091.24	42,091.24
	02 - Steam Generation Plant	SJRPP - Comm	31200	2.60%	2,292.39	2,292.39
	02 - Steam Generation Plant	TurkeyPt Comm Fsil	31100	2.10%	87,560.23	87,560.23
	02 - Steam Generation Plant	TurkeyPt U2	31100	2.10%	42,158.96	42,158.96
	05 - Other Generation Plant	FtLauderdale Comm	34200	3.80%	898,110.65	898,110.65
	05 - Other Generation Plant	FtLauderdale GTs	34200	2.60%	584,290.23	584,290.23
	05 - Other Generation Plant	FtMyers GTs	34200	2.70%	140,654.89	133,478.89
	05 - Other Generation Plant	PtEverglades GTs	34200	2.60%	2,359,099.94	2,359,099.94
	05 - Other Generation Plant	Putnam Comm	34200	2.90%	749,025.94	749,025.94
05 - Maintenance of Above Ground Fuel Tanks Total					**11,733,316.29**	**11,737,140.29**
07 - Relocate Turbine Lube Oil Piping						
	03 - Nuclear Generation Plant	StLucie U1	32300	2.40%	31,030.00	31,030.00
07 - Relocate Turbine Lube Oil Piping Total					**31,030.00**	**31,030.00**
08 - Oil Spill Clean-up/Response Equipment						
	02 - Steam Generation Plant	Amortizable	31650	5-Year	86,360.48	103,360.48
	02 - Steam Generation Plant	Amortizable	31670	7-Year	364,984.05	393,302.05
	02 - Steam Generation Plant	Manatee Comm	31100	2.10%	0.00	3,000.00
	02 - Steam Generation Plant	Martin Comm	31600	2.40%	23,107.32	23,107.32
	02 - Steam Generation Plant	PtEverglades Comm	31100	1.90%	0.00	365,962.73
	05 - Other Generation Plant	Amortizable	34650	5-Year	22,458.48	22,458.48
	05 - Other Generation Plant	Amortizable	34670	7-Year	43,232.74	31,180.89
	08 - General Plant		39000	2.10%	0.00	4,412.76
08 - Oil Spill Clean-up/Response Equipment Total					**540,143.07**	**946,784.71**
10 - Reroute Storm Water Runoff						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.80%	117,793.83	117,793.83
10 - Reroute Storm Water Runoff Total					**117,793.83**	**117,793.83**
12 - Scherer Discharge Pipline						
	02 - Steam Generation Plant	Scherer Comm	31000	0.00%	9,936.72	9,936.72
	02 - Steam Generation Plant	Scherer Comm	31100	2.10%	524,872.97	524,872.97
	02 - Steam Generation Plant	Scherer Comm	31200	2.60%	328,761.62	328,761.62
	02 - Steam Generation Plant	Scherer Comm	31400	2.60%	689.11	689.11
12 - Scherer Discharge Pipline Total					**864,260.42**	**864,260.42**
20 - Wastewater/Stormwater Discharge Elimination						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	0.00%	0.00	0.00
	02 - Steam Generation Plant	Martin U1	31200	2.60%	380,994.77	380,994.77
	02 - Steam Generation Plant	Martin U2	31200	2.60%	416,671.92	416,671.92
	02 - Steam Generation Plant	PtEverglades Comm	31100	1.90%	665,195.32	436,440.86
20 - Wastewater/Stormwater Discharge Elimination Total					**1,462,862.01**	**1,234,107.55**
21 - St. Lucie Turtle Nets						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.80%	352,942.34	352,942.34
21 - St. Lucie Turtle Nets Total					**352,942.34**	**352,942.34**
22 - Pipeline Integrity						
	02 - Steam Generation Plant	Martin Comm	31100	2.10%	0.00	1,229,528.00
22 - Pipeline Integrity Total					**0.00**	**1,229,528.00**

Florida Power & Light Company
Environmental Cost Recovery Clause
2011 Annual Capital Depreciation Schedule

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Actual Balance December 2010	Estimated Balance December 2011
23 - Spill Prevention Clean-Up & Countermeasures						
	02 - Steam Generation Plant	Cutler Comm	31400	2.20%	12,236.00	12,236.00
	02 - Steam Generation Plant	Cutler U5	31400	2.20%	18,388.00	18,388.00
	02 - Steam Generation Plant	Manatee Comm	31100	2.10%	749,862.61	807,718.60
	02 - Steam Generation Plant	Manatee Comm	31200	2.60%	33,272.38	33,272.38
	02 - Steam Generation Plant	Manatee Comm	31500	2.40%	26,325.43	26,325.43
	02 - Steam Generation Plant	Manatee U1	31200	2.60%	45,749.52	45,749.52
	02 - Steam Generation Plant	Manatee U2	31200	2.60%	37,431.45	37,431.45
	02 - Steam Generation Plant	Martin Comm	31100	2.10%	343,785.10	343,785.10
	02 - Steam Generation Plant	Martin Comm	31500	2.40%	34,754.74	34,754.74
	02 - Steam Generation Plant	PtEverglades Comm	31100	1.90%	2,967,754.07	2,967,754.07
	02 - Steam Generation Plant	PtEverglades Comm	31200	6.10%	159,113.30	159,754.32
	02 - Steam Generation Plant	PtEverglades Comm	31500	2.00%	7,782.85	7,782.85
	02 - Steam Generation Plant	Sanford U3	31100	1.90%	850,530.75	850,530.75
	02 - Steam Generation Plant	Sanford U3	31200	2.40%	211,727.22	211,727.22
	02 - Steam Generation Plant	TurkeyPt Comm Fsil	31100	2.10%	92,013.09	92,013.09
	02 - Steam Generation Plant	TurkeyPt Comm Fsil	31500	2.20%	13,559.00	13,559.00
	03 - Nuclear Generation Plant	StLucie Comm	32400	1.80%	0.00	5,000.00
	03 - Nuclear Generation Plant	StLucie U1	32300	2.40%	1,019,294.68	1,019,614.24
	03 - Nuclear Generation Plant	StLucie U1	32400	1.80%	437,945.38	437,945.38
	03 - Nuclear Generation Plant	StLucie U2	32300	2.40%	552,389.64	552,389.64
	05 - Other Generation Plant	Amortizable	34670	7-Year	7,065.10	7,065.10
	05 - Other Generation Plant	FtLauderdale Comm	34100	3.50%	189,219.17	189,219.17
	05 - Other Generation Plant	FtLauderdale Comm	34200	3.80%	1,480,169.46	1,480,169.46
	05 - Other Generation Plant	FtLauderdale Comm	34300	6.00%	28,250.00	28,250.00
	05 - Other Generation Plant	FtLauderdale GTs	34100	2.20%	92,726.74	92,726.74
	05 - Other Generation Plant	FtLauderdale GTs	34200	2.60%	513,250.07	513,250.07
	05 - Other Generation Plant	FtMyers GTs	34100	2.30%	98,714.92	98,714.92
	05 - Other Generation Plant	FtMyers GTs	34200	2.70%	629,983.29	629,983.29
	05 - Other Generation Plant	FtMyers GTs	34500	2.20%	12,430.00	12,430.00
	05 - Other Generation Plant	FtMyers U2 CC	34300	4.20%	49,727.00	49,727.00
	05 - Other Generation Plant	FtMyers U3 CC	34500	3.40%	12,430.00	12,430.00
	05 - Other Generation Plant	Martin Comm	34100	3.50%	61,215.95	61,215.95
	05 - Other Generation Plant	Martin U8	34200	3.80%	84,868.00	84,868.00
	05 - Other Generation Plant	PtEverglades GTs	34100	2.20%	454,080.68	454,080.68
	05 - Other Generation Plant	PtEverglades GTs	34200	2.60%	1,836,482.98	1,835,189.50
	05 - Other Generation Plant	PtEverglades GTs	34500	2.10%	7,782.85	7,782.85
	05 - Other Generation Plant	Putnam Comm	34100	2.60%	148,511.20	148,511.20
	05 - Other Generation Plant	Putnam Comm	34200	2.90%	1,713,191.94	1,733,971.58
	05 - Other Generation Plant	Putnam Comm	34500	2.50%	60,746.93	60,746.93
	06 - Transmission Plant - Electric		35200	1.90%	1,042,156.83	1,050,156.83
	06 - Transmission Plant - Electric		35300	2.60%	177,981.88	177,981.88
	06 - Transmission Plant - Electric		35800	1.80%	0.00	64,088.54
	07 - Distribution Plant - Electric		36100	1.90%	2,931,887.67	2,963,887.67
	07 - Distribution Plant - Electric		36670	2.00%	0.00	81,787.45
	08 - General Plant		39000	2.10%	99,812.99	146,691.32
23 - Spill Prevention Clean-Up & Countermeasures Total					**19,346,600.86**	**19,662,657.91**
24 - Manatee Reburn						
	02 - Steam Generation Plant	Manatee U1	31200	2.60%	16,687,067.37	16,687,067.37
	02 - Steam Generation Plant	Manatee U2	31200	2.60%	15,062,479.29	15,062,479.29
24 - Manatee Reburn Total					**31,749,546.66**	**31,749,546.66**
25 - PPE ESP Technology						
	02 - Steam Generation Plant	PtEverglades U1	31100	1.90%	298,709.93	298,709.93
	02 - Steam Generation Plant	PtEverglades U1	31200	2.30%	10,404,603.15	10,404,603.15
	02 - Steam Generation Plant	PtEverglades U1	31500	2.00%	2,500,248.85	2,500,248.85
	02 - Steam Generation Plant	PtEverglades U1	31600	2.10%	307,032.30	307,032.30
	02 - Steam Generation Plant	PtEverglades U2	31100	1.90%	184,084.01	184,084.01
	02 - Steam Generation Plant	PtEverglades U2	31200	2.30%	11,979,735.29	11,979,735.29
	02 - Steam Generation Plant	PtEverglades U2	31500	2.00%	3,954,581.63	3,954,581.63
	02 - Steam Generation Plant	PtEverglades U2	31600	2.10%	324,086.94	324,086.94
	02 - Steam Generation Plant	PtEverglades U3	31100	1.90%	713,693.44	713,693.44
	02 - Steam Generation Plant	PtEverglades U3	31200	2.30%	18,160,533.65	18,160,533.65
	02 - Steam Generation Plant	PtEverglades U3	31500	2.00%	4,304,056.69	4,304,056.69
	02 - Steam Generation Plant	PtEverglades U3	31600	2.10%	528,541.18	528,541.18
	02 - Steam Generation Plant	PtEverglades U4	31100	1.90%	313,275.79	313,275.79
	02 - Steam Generation Plant	PtEverglades U4	31200	2.30%	20,646,501.29	20,646,501.29
	02 - Steam Generation Plant	PtEverglades U4	31500	2.00%	6,729,950.05	6,729,950.05
	02 - Steam Generation Plant	PtEverglades U4	31600	2.10%	551,535.30	551,535.30
25 - PPE ESP Technology Total					**81,901,169.49**	**81,901,169.49**

Florida Power & Light Company
Environmental Cost Recovery Clause
2011 Annual Capital Depreciation Schedule

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Actual Balance December 2010	Estimated Balance December 2011
26 - UST Remove/Replace						
	08 - General Plant		39000	2.10%	492,916.42	115,446.69
26 - UST Remove/Replace Total					**492,916.42**	**115,446.69**
31 - Clean Air Interstate Rule (CAIR)						
	02 - Steam Generation Plant	Manatee Comm	31100	2.10%	102,052.47	102,052.47
	02 - Steam Generation Plant	Manatee Comm	31200	2.60%	0.00	518,274.99
	02 - Steam Generation Plant	Manatee U1	31200	2.60%	19,794,254.26	20,059,060.47
	02 - Steam Generation Plant	Manatee U1	31400	2.60%	6,219,701.47	7,270,679.87
	02 - Steam Generation Plant	Manatee U2	31200	2.60%	13,163,149.00	20,493,592.71
	02 - Steam Generation Plant	Manatee U2	31400	2.60%	7,918,302.41	8,121,992.61
	02 - Steam Generation Plant	Martin Comm	31400	2.60%	287,257.77	287,257.77
	02 - Steam Generation Plant	Martin U1	31200	2.60%	14,651,505.23	20,695,251.33
	02 - Steam Generation Plant	Martin U1	31400	2.60%	7,694,692.34	7,788,541.34
	02 - Steam Generation Plant	Martin U2	31200	2.60%	20,683,349.06	19,057,799.99
	02 - Steam Generation Plant	Martin U2	31400	2.60%	7,385,556.36	7,487,256.36
	02 - Steam Generation Plant	SJRPP U1	31200	2.60%	28,172,582.67	27,708,298.93
	02 - Steam Generation Plant	SJRPP U1	31500	2.40%	0.00	455,145.91
	02 - Steam Generation Plant	SJRPP U1	31600	2.40%	0.00	9,137.83
	02 - Steam Generation Plant	SJRPP U2	31200	2.60%	27,066,114.22	26,630,303.07
	02 - Steam Generation Plant	SJRPP U2	31500	2.40%	0.00	426,219.91
	02 - Steam Generation Plant	SJRPP U2	31600	2.40%	0.00	9,591.24
	05 - Other Generation Plant	FtLauderdale GTs	34300	2.90%	110,241.57	110,241.57
	05 - Other Generation Plant	FtMyers GTs	34300	3.10%	57,855.19	57,855.19
	05 - Other Generation Plant	Martin Comm	34100	3.50%	762,997.86	763,350.13
	05 - Other Generation Plant	Martin Comm	34300	4.30%	244,230.62	244,343.38
	05 - Other Generation Plant	Martin Comm	34500	3.40%	292,363.70	292,498.67
	05 - Other Generation Plant	PtEverglades GTs	34300	3.40%	107,874.44	107,874.44
	07 - Distribution Plant - Electric		36500	3.90%	0.00	411,775.23
31 - Clean Air Interstate Rule (CAIR) Total					**154,714,080.64**	**169,108,395.41**
33 - Clean Air Mercury Rule (CAMR)						
	02 - Steam Generation Plant	Scherer U4	31200	2.60%	105,905,052.28	107,265,403.72
33 - Clean Air Mercury Rule (CAMR) Total					**105,905,052.28**	**107,265,403.72**
35 - Martin Drinking Water System						
	02 - Steam Generation Plant	Martin Comm	31100	2.10%	235,391.32	235,391.32
35 - Martin Drinking Water System Total					**235,391.32**	**235,391.32**
36 - Low Level Waste Storage						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.80%	0.00	6,926,841.52
36 - Low Level Waste Storage Total					**0.00**	**6,926,841.52**
37 - DeSoto Solar Energy Center						
	05 - Other Generation Plant	Amortizable	34630	3-Year	12,102.91	12,102.91
	05 - Other Generation Plant	Amortizable	34650	5-Year	21,934.62	21,934.62
	05 - Other Generation Plant	Amortizable	34670	7-Year	50,094.94	79,264.09
	05 - Other Generation Plant	DeSoto Solar	34000	0.00%	255,507.00	255,507.00
	05 - Other Generation Plant	DeSoto Solar	34100	3.30%	3,249,119.87	4,449,376.76
	05 - Other Generation Plant	DeSoto Solar	34300	3.30%	141,636,734.40	116,103,531.68
	05 - Other Generation Plant	DeSoto Solar	34500	3.30%	0.00	26,137,080.76
	06 - Transmission Plant - Electric		35200	1.90%	2,603.27	2,603.27
	06 - Transmission Plant - Electric		35300	2.60%	797,283.55	797,283.55
	06 - Transmission Plant - Electric		35310	2.90%	1,712,305.00	1,712,305.00
	06 - Transmission Plant - Electric		35500	3.40%	394,417.57	394,417.57
	06 - Transmission Plant - Electric		35600	3.20%	191,357.87	191,357.87
	07 - Distribution Plant - Electric		36100	1.90%	608,237.66	608,237.66
	07 - Distribution Plant - Electric		36200	2.60%	2,238,948.26	2,214,848.49
	08 - General Plant		39220	9.40%	28,426.16	28,426.16
	08 - General Plant	Amortizable	39720	7-Year	22,344.95	22,113.81
37 - DeSoto Solar Energy Center Total					**151,221,418.03**	**153,030,391.20**

Florida Power & Light Company
Environmental Cost Recovery Clause
2011 Annual Capital Depreciation Schedule

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Actual Balance December 2010	Estimated Balance December 2011
38 - Spacecoast Solar Energy Center						
	01 - Intangible Plant	Amortizable	30300	30-Year	6,359,027.00	6,359,027.00
	05 - Other Generation Plant	Amortizable	34630	3-Year	7,271.71	7,271.71
	05 - Other Generation Plant	Amortizable	34650	5-Year	9,438.49	9,438.49
	05 - Other Generation Plant	Amortizable	34670	7-Year	37,454.78	40,744.77
	05 - Other Generation Plant	Spacecoast Solar	34100	3.30%	1,208,355.56	1,208,992.67
	05 - Other Generation Plant	Spacecoast Solar	34300	3.30%	60,328,241.78	60,362,804.15
	05 - Other Generation Plant	Spacecoast Solar	34600	3.30%	0.00	7,210.00
	06 - Transmission Plant - Electric		35300	2.60%	139,390.84	139,390.84
	07 - Distribution Plant - Electric		36100	1.90%	269,763.87	269,805.86
	07 - Distribution Plant - Electric		36200	2.60%	2,186,607.33	2,187,146.99
	08 - General Plant		39220	9.40%	31,858.14	31,858.14
	08 - General Plant	Amortizable	39720	7-Year	6,356.95	6,350.40
38 - Spacecoast Solar Energy Center Total					**70,583,766.45**	**70,630,041.02**
39 - Martin Solar Energy Center						
	05 - Other Generation Plant	Amortizable	34650	5-Year	21,384.00	21,384.00
	05 - Other Generation Plant	Martin Solar	34000	0.00%	216,844.31	216,844.31
	05 - Other Generation Plant	Martin Solar	34100	3.30%	90.55	90.55
	05 - Other Generation Plant	Martin Solar	34300	3.30%	390,586,865.63	398,522,547.42
	05 - Other Generation Plant	Martin Solar	34600	3.30%	1,152.33	1,299.31
	05 - Other Generation Plant	Martin U8	34300	4.30%	300,334.49	379,929.68
	06 - Transmission Plant - Electric		35500	3.40%	618,700.98	618,700.98
	06 - Transmission Plant - Electric		35600	3.20%	368,305.53	368,305.53
	07 - Distribution Plant - Electric		36400	4.10%	9,282.42	9,282.42
	07 - Distribution Plant - Electric		36660	1.50%	0.00	94,476.14
	07 - Distribution Plant - Electric		36760	2.60%	2,728.36	2,728.36
	08 - General Plant		39220	9.40%	0.00	25,193.18
	08 - General Plant		39240	11.10%	0.00	205,307.14
	08 - General Plant		39290	3.50%	0.00	97,633.07
	08 - General Plant	Amortizable	39420	7-Year	0.00	18,992.89
	08 - General Plant	Amortizable	39720	7-Year	0.00	3,203.99
39 - Martin Solar Energy Center Total					**392,125,688.60**	**400,585,918.97**
41 - Manatee Heaters						
	02 - Steam Generation Plant	CapeCanaveral Comm	31400	0.70%	3,502,299.42	4,627,040.58
	02 - Steam Generation Plant	Riviera Comm	31400	0.60%	2,605,268.34	2,605,268.34
	06 - Transmission Plant - Electric		35300	2.60%	282,951.11	283,596.40
	07 - Distribution Plant - Electric		36100	1.90%	9,669.19	29,779.49
	07 - Distribution Plant - Electric		36200	2.60%	322,202.56	484,745.22
	07 - Distribution Plant - Electric		36400	4.10%	186,148.51	223,459.91
	07 - Distribution Plant - Electric		36500	3.90%	271,244.89	302,616.24
	07 - Distribution Plant - Electric		36660	1.50%	119,589.43	221,325.50
	07 - Distribution Plant - Electric		36760	2.60%	105,249.65	168,995.42
	07 - Distribution Plant - Electric		36910	3.90%	607.49	607.06
	08 - General Plant	Amortizable	39720	7-Year	7,620.86	23,287.46
41 - Manatee Heaters Total					**7,412,851.45**	**8,970,721.62**
42 - Turkey Point Cooling Canal Monitoring						
	03 - Nuclear Generation Plant	TurkeyPt Comm	32100	1.80%	3,593,540.81	3,582,752.89
42 - Turkey Point Cooling Canal Monitoring Total					**3,593,540.81**	**3,582,752.89**
44 - Martin Plant Barley Barber Swamp Iron Mitigation Project						
	02 - Steam Generation Plant	Martin Comm	31100	2.10%	0.00	147,578.17
44 - Martin Plant Barley Barber Swamp Iron Mitigation Project Total					**0.00**	**147,578.17**
Grand Total					**1,054,555,260.62**	**1,090,596,733.38**

FLORIDA POWER & LIGHT COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE

Equity @ 10.00%

CAPITAL STRUCTURE AND COST RATES PER 2009 RATE CASE (a)
Docket No 080677-EI Order No PSC-10-0153-FOF-EI

	ADJUSTED RETAIL	RATIO	MIDPOINT COST RATES	WEIGHTED COST	PRE-TAX WEIGHTED COST
LONG TERM DEBT	5,298,960,654	31.565%	5.49%	1.73%	1.73%
SHORT TERM DEBT	156,113,805	0.930%	2.11%	0.02%	0.02%
PREFERRED STOCK	0	0.000%	0.00%	0.00%	0.00%
CUSTOMER DEPOSITS	544,711,775	3.245%	5.98%	0.19%	0.19%
COMMON EQUITY	7,889,967,199	46.999%	10.00%	4.70%	7.65%
DEFERRED INCOME TAX	2,892,247,084	17.229%	0.00%	0.00%	0.00%
INVESTMENT TAX CREDITS					
ZERO COST	0	0.000%	0.00%	0.00%	0.00%
WEIGHTED COST	5,429,401	0.032%	8.19%	0.00%	
			0		
TOTAL	$16,787,429,918	100.00%		6.65%	9.60%

CALCULATION OF THE WEIGHTED COST FOR CONVERTIBLE INVESTMENT TAX CREDITS (C-ITC) (b)

	ADJUSTED RETAIL	RATIO	COST RATE	WEIGHTED COST	PRE TAX COST
LONG TERM DEBT	$5,298,960,654	40.18%	5.49%	2.21%	2.21%
PREFERRED STOCK	0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	7,889,967,199	59.82%	10.00%	5.98%	9.74%
TOTAL	$13,188,927,853	100.00%		8.19%	11.94%
RATIO					

DEBT COMPONENTS:

LONG TERM DEBT	1.7329%
SHORT TERM DEBT	0.0196%
CUSTOMER DEPOSITS	0.1940%
TAX CREDITS -WEIGHTED	0.0007%
TOTAL DEBT	**1.9473%**

EQUITY COMPONENTS:

PREFERRED STOCK	0.0000%
COMMON EQUITY	4.6999%
TAX CREDITS -WEIGHTED	0.0019%
TOTAL EQUITY	**4.7019%**
TOTAL	6.6492%
PRE-TAX EQUITY	7.6546%
PRE-TAX TOTAL	9.6019%

Note:
(a) Reflects approved capital structure and ROE reflected in Docket 080677-EI which ended in Order No. PSC-10-0153-FOF-EI. The above capital structure started effective March 2010.
(b) This capital structure applies only to Convertible Investment Tax Credit (C-ITC).

Appendix II

ASME/BSR MFC 12M, "Flow in Closed Conduits Using Multiport Averaging Pitot Primary Flowmeters," for EPA Method 2.

Section 63.7520 and Tables 4A through 4D to subpart DDDDD, 40 CFR part 63, list the EPA testing methods included in the proposed rule. Under § 63.7(f) and § 63.8(f) of subpart A of the General Provisions, a source may apply to EPA for permission to use alternative test methods or alternative monitoring requirements in place of any of the EPA testing methods, performance specifications, or procedures.

J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes Federal executive policy on environmental justice (EJ). Its main provision directs Federal agencies, to the greatest extent practicable and permitted by law, to make environmental justice part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations, low-income, and Tribal populations in the United States.

This final action establishes national emission standards for new and existing industrial, commercial, institutional boilers and process heaters that combust non-waste materials (*i.e.* natural gas, process gas, fuel oil, biomass, and coal) and that are located at a major source. EPA estimates that there are approximately 13,840 units located at 1,639 facilities covered by this final rule.

This final rule will reduce emissions of all the listed HAP that come from boilers and process heaters. This includes metals (Hg, arsenic, beryllium, cadmium, chromium, lead, Mn, nickel, and selenium), organics (POM, acetaldehyde, acrolein, benzene, dioxin/furan, ethylene dichloride, formaldehyde, and polychlorinated biphenyls), hydrochloric acid, and hydrofluoric acid. Adverse health effects from these pollutants include cancer, irritation of the lungs, skin, and mucus membranes; effects on the central nervous system, damage to the kidneys, and other acute health disorders. This final rule will also result in substantial reductions of criteria pollutants such as CO, NO_X, PM, and SO_2. SO_2 and nitrogen dioxide are precursors for the formation of $PM_{2.5}$ and ozone. Reducing these emissions will reduce ozone and $PM_{2.5}$ formation and associated health effects, such as adult premature mortality, chronic and acute bronchitis, asthma, and other respiratory and cardiovascular diseases. (Please refer to the RIA contained in the docket for this rulemaking.)

Based on the fact that this final rule does not allow emission increases, EPA has determined that this final rule will not have disproportionately high and adverse human health or environmental effects on minority, low-income, or Tribal populations. To address Executive Order 12898, EPA has conducted analyses to determine the aggregate demographic makeup of the communities near affected sources. EPA's demographic analysis of populations within the three-mile radius showed that major source boilers are located in areas where minorities are overrepresented when compared to the national average. For these same areas, there is also an overrepresentation of population below the poverty line as compared to the national average. The results of the demographic analysis are presented in "Review of Environmental Justice Impacts", April 2010, a copy of which is available in the docket. However, to the extent that any minority, low income, or Tribal subpopulation is disproportionately impacted by the current emissions as a result of the proximity of their homes to these sources, that subpopulation also stands to see increased environmental and health benefit from the emissions reductions called for by this rule.

EPA defines "Environmental Justice" to include meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and polices. To promote meaningful involvement, EPA has developed a communication and outreach strategy to ensure that interested communities have access to this final rule and are aware of its content. EPA also ensured that interested communities had an opportunity to comment during the comment period. During the comment period that followed the June 2010 proposal, EPA publicized the rulemaking via EJ newsletters, Tribal newsletters, EJ listservs, and the internet, including the Office of Policy's (OP) Rulemaking Gateway Web site (*http://yosemite.epa.gov/opei/RuleGate.nsf/*). EPA will also provide general rulemaking fact sheets (*e.g.*, why is this important for my community) for EJ community groups and conduct conference calls with interested communities. In addition, State and federal permitting requirements will provide State and local governments and members of affected communities the opportunity to provide comments on the permit conditions associated with permitting the sources affected by this rulemaking.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report, which includes a copy of the rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this final rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a "major rule" as defined by 5 U.S.C. 804(2). This rule will be effective May 20, 2011.

List of Subjects in 40 CFR part 63

Environmental protection, Administrative practice and procedure, Air pollution control, Hazardous substances, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: February 21, 2011.

Lisa P. Jackson,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, part 63 of the Code of the Federal Regulations is amended as follows:

PART 63—[AMENDED]

■ 1. The authority citation for part 63 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

■ 2. Section 63.14 is amended by:
■ a. Revising paragraphs (b)(27), (b)(35), (b)(39) through (44), (b)(47) through (52), (b)(57), (b)(61), (b)(64), and (i)(1).
■ b. Removing and reserving paragraphs (b)(45), (b)(46), (b)(55), (b)(56), (b)(58) through (60), and (b)(62).
■ c. Adding paragraphs (b)(66) through (68).
■ d. Adding paragraphs (p) and (q).

§ 63.14 Incorporations by reference.

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(b) * * *

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(27) ASTM D6522–00, Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from

Natural Gas Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, IBR approved for § 63.9307(c)(2).

* * * * *

(35) ASTM D6784–02 (Reapproved 2008) Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), approved April 1, 2008, IBR approved for table 1 to subpart DDDDD of this part, table 2 to subpart DDDDD of this part, table 5 to subpart DDDDD of this part, table 12 to subpart DDDDD of this part, and table 4 to subpart JJJJJ of this part.

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(39) ASTM D388–05 Standard Classification of Coals by Rank, approved September 15, 2005, IBR approved for § 63.7575 and § 63.11237.

(40) ASTM D396–10 Standard Specification for Fuel Oils, approved October 1, 2010, IBR approved for § 63.7575.

(41) ASTM D1835–05 Standard Specification for Liquefied Petroleum (LP) Gases, approved April 1, 2005, IBR approved for § 63.7575 and § 63.11237.

(42) ASTM D2013/D2013M–09 Standard Practice for Preparing Coal Samples for Analysis, approved November 1, 2009, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJ of this part.

(43) ASTM D2234/D2234M–10 Standard Practice for Collection of a Gross Sample of Coal, approved January 1, 2010, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJ of this part.

(44) ASTM D3173–03 (Reapproved 2008) Standard Test Method for Moisture in the Analysis Sample of Coal and Coke, approved February 1, 2008, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJ of this part.

* * * * *

(47) ASTM D5198–09 Standard Practice for Nitric Acid Digestion of Solid Waste, approved February 1, 2009, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJ of this part.

(48) ASTM D5865–10a Standard Test Method for Gross Calorific Value of Coal and Coke, approved May 1, 2010, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJ of this part.

(49) ASTM D6323–98 (Reapproved 2003) Standard Guide for Laboratory Subsampling of Media Related to Waste Management Activities, approved August 10, 2003, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJ of this part.

(50) ASTM E711–87 (Reapproved 2004) Standard Test Method for Gross Calorific Value of Refuse-Derived Fuel by the Bomb Calorimeter, approved August 28, 1987, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJ of this part.

(51) ASTM E776–87 (Reapproved 2009) Standard Test Method for Forms of Chlorine in Refuse-Derived Fuel, approved July 1, 2009, IBR approved for table 6 to subpart DDDDD of this part.

(52) ASTM E871–82 (Reapproved 2006) Standard Test Method for Moisture Analysis of Particulate Wood Fuels, approved November 1, 2006, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJ of this part.

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(57) ASTM D6721–01 (Reapproved 2006) Standard Test Method for Determination of Chlorine in Coal by Oxidative Hydrolysis Microcoulometry, approved April 1, 2006, IBR approved for table 6 to subpart DDDDD of this part.

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(61) ASTM D6722–01 (Reapproved 2006) Standard Test Method for Total Mercury in Coal and Coal Combustion Residues by the Direct Combustion Analysis, approved April 1, 2006, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJ of this part.

* * * * *

(64) ASTM D6522–00 (Reapproved 2005), Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, approved October 1, 2005, IBR approved for table 4 to subpart ZZZZ of this part, table 5 to subpart DDDDD of this part, and table 4 to subpart JJJJJ of this part.

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(66) ASTM D4084–07 Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), approved June 1, 2007, IBR approved for table 6 to subpart DDDDD of this part.

(67) ASTM D5954–98 (Reapproved 2006), Standard Test Method for Mercury Sampling and Measurement in Natural Gas by Atomic Absorption Spectroscopy, approved December 1, 2006, IBR approved for table 6 to subpart DDDDD of this part.

(68) ASTM D6350–98 (Reapproved 2003) Standard Test Method for Mercury Sampling and Analysis in Natural Gas by Atomic Fluorescence Spectroscopy, approved May 10, 2003, IBR approved for table 6 to subpart DDDDD of this part.

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(1) ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus]," IBR approved for §§ 63.309(k)(1)(iii), 63.865(b), 63.3166(a)(3), 63.3360(e)(1)(iii), 63.3545(a)(3), 63.3555(a)(3), 63.4166(a)(3), 63.4362(a)(3), 63.4766(a)(3), 63.4965(a)(3), 63.5160(d)(1)(iii), 63.9307(c)(2), 63.9323(a)(3), 63.11148(e)(3)(iii), 63.11155(e)(3), 63.11162(f)(3)(iii) and (f)(4), 63.11163(g)(1)(iii) and (g)(2), 63.11410(j)(1)(iii), 63.11551(a)(2)(i)(C), table 5 to subpart DDDDD of this part, table 1 to subpart ZZZZZ of this part, and table 4 to subpart JJJJJ of this part.

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(p) The following material is available from the U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue, NW., Washington, DC 20460, (202) 272–0167, *http://www.epa.gov.*

(1) National Emission Standards for Hazardous Air Pollutants (NESHAP) for Integrated Iron and Steel Plants—Background Information for Proposed Standards, Final Report, EPA–453/R–01–005, January 2001, IBR approved for § 63.7491(g).

(2) Office Of Air Quality Planning And Standards (OAQPS), Fabric Filter Bag Leak Detection Guidance, EPA–454/R–98–015, September 1997, IBR approved for § 63.7525(j)(2) and § 63.11224(f)(2).

(3) SW–846–3020A, Acid Digestion of Aqueous Samples And Extracts For Total Metals For Analysis By GFAA Spectroscopy, Revision 1, July 1992, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJ of this part.

(4) SW–846–3050B, Acid Digestion of Sediments, Sludges, And Soils, Revision 2, December 1996, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJ of this part.

(5) SW–846–7470A, Mercury In Liquid Waste (Manual Cold-Vapor Technique), Revision 1, September 1994, in EPA Publication No. SW–846,

Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJJ of this part.

(6) SW–846–7471B, Mercury In Solid Or Semisolid Waste (Manual Cold-Vapor Technique), Revision 2, February 2007, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJJ of this part.

(7) SW–846–9250, Chloride (Colorimetric, Automated Ferricyanide AAI), Revision 0, September 1986, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD of this part.

(q) The following material is available for purchase from the International Standards Organization (ISO), 1, ch. de la Voie-Creuse, Case postale 56, CH–1211 Geneva 20, Switzerland, +41 22 749 01 11, *http://www.iso.org/iso/home.htm*.

(1) ISO 6978–1:2003(E), Natural Gas—Determination of Mercury—Part 1: Sampling of Mercury by Chemisorption on Iodine, First edition, October 15, 2003, IBR approved for table 6 to subpart DDDDD of this part.

(2) ISO 6978–2:2003(E), Natural gas—Determination of Mercury—Part 2: Sampling of Mercury by Amalgamation on Gold/Platinum Alloy, First edition, October 15, 2003, IBR approved for table 6 to subpart DDDDD of this part.

■ 3. Part 63 is amended by revising subpart DDDDD to read as follows:

Subpart DDDDD—National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

Sec.

What This Subpart Covers

§ 63.7480 What is the purpose of this subpart?

This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from industrial, commercial, and institutional boilers and process heaters located at major sources of HAP. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations and work practice standards.

§ 63.7485 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler or process heater as defined in § 63.7575 that is located at, or is part of, a major source of HAP, except as specified in § 63.7491. For purposes of this subpart, a major source of HAP is as defined in § 63.2, except that for oil and natural gas production facilities, a major source of HAP is as defined in § 63.761 (subpart HH of this part, National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities).

§ 63.7490 What is the affected source of this subpart?

(a) This subpart applies to new, reconstructed, and existing affected sources as described in paragraphs (a)(1) and (2) of this section.

(1) The affected source of this subpart is the collection at a major source of all existing industrial, commercial, and institutional boilers and process heaters within a subcategory as defined in § 63.7575.

(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler or

process heater, as defined in § 63.7575, located at a major source.

(b) A boiler or process heater is new if you commence construction of the boiler or process heater after June 4, 2010, and you meet the applicability criteria at the time you commence construction.

(c) A boiler or process heater is reconstructed if you meet the reconstruction criteria as defined in § 63.2, you commence reconstruction after June 4, 2010, and you meet the applicability criteria at the time you commence reconstruction.

(d) A boiler or process heater is existing if it is not new or reconstructed.

§ 63.7491 Are any boilers or process heaters not subject to this subpart?

The types of boilers and process heaters listed in paragraphs (a) through (m) of this section are not subject to this subpart.

(a) An electric utility steam generating unit.

(b) A recovery boiler or furnace covered by subpart MM of this part.

(c) A boiler or process heater that is used specifically for research and development. This does not include units that provide heat or steam to a process at a research and development facility.

(d) A hot water heater as defined in this subpart.

(e) A refining kettle covered by subpart X of this part.

(f) An ethylene cracking furnace covered by subpart YY of this part.

(g) Blast furnace stoves as described in EPA–453/R–01–005 (incorporated by reference, see § 63.14).

(h) Any boiler or process heater that is part of the affected source subject to another subpart of this part (i.e., another National Emission Standards for Hazardous Air Pollutants in 40 CFR part 63).

(i) Any boiler or process heater that is used as a control device to comply with another subpart of this part, provided that at least 50 percent of the heat input to the boiler is provided by the gas stream that is regulated under another subpart.

(j) Temporary boilers as defined in this subpart.

(k) Blast furnace gas fuel-fired boilers and process heaters as defined in this subpart.

(l) Any boiler specifically listed as an affected source in any standard(s) established under section 129 of the Clean Air Act.

(m) A boiler required to have a permit under section 3005 of the Solid Waste Disposal Act or covered by subpart EEE of this part (e.g., hazardous waste boilers).

§ 63.7495 When do I have to comply with this subpart?

(a) If you have a new or reconstructed boiler or process heater, you must comply with this subpart by May 20, 2011 or upon startup of your boiler or process heater, whichever is later.

(b) If you have an existing boiler or process heater, you must comply with this subpart no later than March 21, 2014.

(c) If you have an area source that increases its emissions or its potential to emit such that it becomes a major source of HAP, paragraphs (c)(1) and (2) of this section apply to you.

(1) Any new or reconstructed boiler or process heater at the existing source must be in compliance with this subpart upon startup.

(2) Any existing boiler or process heater at the existing source must be in compliance with this subpart within 3 years after the source becomes a major source.

(d) You must meet the notification requirements in § 63.7545 according to the schedule in § 63.7545 and in subpart A of this part. Some of the notifications must be submitted before you are required to comply with the emission limits and work practice standards in this subpart.

(e) If you own or operate an industrial, commercial, or institutional boiler or process heater and would be subject to this subpart except for the exemption in § 63.7491(l) for commercial and industrial solid waste incineration units covered by part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart on the effective date of the switch from waste to fuel.

Emission Limitations and Work Practice Standards

§ 63.7499 What are the subcategories of boilers and process heaters?

The subcategories of boilers and process heaters, as defined in § 63.7575 are:

(a) Pulverized coal/solid fossil fuel units.

(b) Stokers designed to burn coal/solid fossil fuel.

(c) Fluidized bed units designed to burn coal/solid fossil fuel.

(d) Stokers designed to burn biomass/bio-based solid.

(e) Fluidized bed units designed to burn biomass/bio-based solid.

(f) Suspension burners/Dutch Ovens designed to burn biomass/bio-based solid.

(g) Fuel Cells designed to burn biomass/bio-based solid.

(h) Hybrid suspension/grate burners designed to burn biomass/bio-based solid.

(i) Units designed to burn solid fuel.

(j) Units designed to burn liquid fuel.

(k) Units designed to burn liquid fuel in non-continental States or territories.

(l) Units designed to burn natural gas, refinery gas or other gas 1 fuels.

(m) Units designed to burn gas 2 (other) gases.

(n) Metal process furnaces.

(o) Limited-use boilers and process heaters.

§ 63.7500 What emission limitations, work practice standards, and operating limits must I meet?

(a) You must meet the requirements in paragraphs (a)(1) through (3) of this section, except as provided in paragraphs (b) and (c) of this section. You must meet these requirements at all times.

(1) You must meet each emission limit and work practice standard in Tables 1 through 3, and 12 to this subpart that applies to your boiler or process heater, for each boiler or process heater at your source, except as provided under § 63.7522. If your affected source is a new or reconstructed affected source that commenced construction or reconstruction after June 4, 2010, and before May 20, 2011, you may comply with the emission limits in Table 1 or 12 to this subpart until March 21, 2014. On and after March 21, 2014, you must comply with the emission limits in Table 1 to this subpart.

(2) You must meet each operating limit in Table 4 to this subpart that applies to your boiler or process heater. If you use a control device or combination of control devices not covered in Table 4 to this subpart, or you wish to establish and monitor an alternative operating limit and alternative monitoring parameters, you must apply to the EPA Administrator for approval of alternative monitoring under § 63.8(f).

(3) At all times, you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(b) As provided in § 63.6(g), EPA may approve use of an alternative to the work practice standards in this section.

(c) Limited-use boilers and process heaters must complete a biennial tune-up as specified in § 63.7540. They are not subject to the emission limits in Tables 1 and 2 to this subpart, the annual tune-up requirement in Table 3 to this subpart, or the operating limits in Table 4 to this subpart. Major sources that have limited-use boilers and process heaters must complete an energy assessment as specified in Table 3 to this subpart if the source has other existing boilers subject to this subpart that are not limited-use boilers.

§ 63.7501 How can I assert an affirmative defense if I exceed an emission limitations during a malfunction?

In response to an action to enforce the emission limitations and operating limits set forth in § 63.7500 you may assert an affirmative defense to a claim for civil penalties for exceeding such standards that are caused by malfunction, as defined at § 63.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) To establish the affirmative defense in any action to enforce such a limit, you must timely meet the notification requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The excess emissions:

(i) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner, and

(ii) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(iii) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(iv) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(2) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(3) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

(4) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(5) All possible steps were taken to minimize the impact of the excess emissions on ambient air quality, the environment and human health; and

(6) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(7) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

(8) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(b) *Notification.* The owner or operator of the facility experiencing an exceedance of its emission limitat(s) during a malfunction shall notify the Administrator by telephone or facsimile (fax) transmission as soon as possible, but no later than 2 business days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial ocurrence of the exceedance of the standard in § 63.7500 to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

General Compliance Requirements

§ 63.7505 What are my general requirements for complying with this subpart?

(a) You must be in compliance with the emission limits and operating limits in this subpart. These limits apply to you at all times.

(b) [Reserved]

(c) You must demonstrate compliance with all applicable emission limits using performance testing, fuel analysis, or continuous monitoring systems (CMS), including a continuous emission monitoring system (CEMS) or continuous opacity monitoring system (COMS), where applicable. You may demonstrate compliance with the applicable emission limit for hydrogen chloride or mercury using fuel analysis if the emission rate calculated according to § 63.7530(c) is less than the applicable emission limit. Otherwise, you must demonstrate compliance for hydrogen chloride or mercury using performance testing, if subject to an applicable emission limit listed in Table 1, 2, or 12 to this subpart.

(d) If you demonstrate compliance with any applicable emission limit through performance testing and subsequent compliance with operating limits (including the use of continuous parameter monitoring system), or with a CEMS, or COMS, you must develop a site-specific monitoring plan according to the requirements in paragraphs (d)(1) through (4) of this section for the use of any CEMS, COMS, or continuous parameter monitoring system. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under § 63.8(f).

(1) For each CMS required in this section (including CEMS, COMS, or continuous parameter monitoring system), you must develop, and submit to the delegated authority for approval upon request, a site-specific monitoring plan that addresses paragraphs (d)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation of your CMS. This requirement to develop and submit a site specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and COMS prepared under appendix B to part 60 of this chapter and that meet the requirements of § 63.7525.

(i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (e.g., on or downstream of the last control device);

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems; and

(iii) Performance evaluation procedures and acceptance criteria (*e.g.*, calibrations).

(2) In your site-specific monitoring plan, you must also address paragraphs (d)(2)(i) through (iii) of this section.

(i) Ongoing operation and maintenance procedures in accordance with the general requirements of § 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii);

(ii) Ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d); and

(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of § 63.10(c) (as applicable in Table 10 to this subpart), (e)(1), and (e)(2)(i).

(3) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.

(4) You must operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.

Testing, Fuel Analyses, and Initial Compliance Requirements

§ 63.7510 What are my initial compliance requirements and by what date must I conduct them?

(a) For affected sources that elect to demonstrate compliance with any of the applicable emission limits in Tables 1 or 2 of this subpart through performance testing, your initial compliance requirements include conducting performance tests according to § 63.7520 and Table 5 to this subpart, conducting a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart, establishing operating limits according to § 63.7530 and Table 7 to this subpart, and conducting CMS performance evaluations according to § 63.7525. For affected sources that burn a single type of fuel, you are exempted from the compliance requirements of conducting a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart. For purposes of this subpart, units that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as affected sources that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under § 63.7521 and Table 6 to this subpart.

(b) For affected sources that elect to demonstrate compliance with the applicable emission limits in Tables 1 or 2 of this subpart for hydrogen chloride or mercury through fuel analysis, your initial compliance requirement is to conduct a fuel analysis for each type of fuel burned in your boiler or process heater according to § 63.7521 and Table 6 to this subpart and establish operating limits according to § 63.7530 and Table 8 to this subpart.

(c) If your boiler or process heater is subject to a carbon monoxide limit, your initial compliance demonstration for carbon monoxide is to conduct a performance test for carbon monoxide according to Table 5 to this subpart. Your initial compliance demonstration for carbon monoxide also includes conducting a performance evaluation of your continuous oxygen monitor according to § 63.7525(a).

(d) If your boiler or process heater subject to a PM limit has a heat input capacity greater than 250 MMBtu per hour and combusts coal, biomass, or residual oil, your initial compliance demonstration for PM is to conduct a performance evaluation of your continuous emission monitoring system for PM according to § 63.7525(b). Boilers and process heaters that use a continuous emission monitoring system for PM are exempt from the performance testing and operating limit requirements specified in paragraph (a) of this section.

(e) For existing affected sources, you must demonstrate initial compliance, as specified in paragraphs (a) through (d) of this section, no later than 180 days after the compliance date that is specified for your source in § 63.7495 and according to the applicable provisions in § 63.7(a)(2) as cited in Table 10 to this subpart.

(f) If your new or reconstructed affected source commenced construction or reconstruction after June 4, 2010, you must demonstrate initial compliance with the emission limits no later than November 16, 2011 or within 180 days after startup of the source, whichever is later. If you are demonstrating compliance with an emission limit in Table 12 to this subpart that is less stringent than (that is, higher than) the applicable emission limit in Table 1 to this subpart, you must demonstrate compliance with the applicable emission limit in Table 1 no later than September 17, 2014.

(g) For affected sources that ceased burning solid waste consistent with § 63.7495(e) and for which your initial compliance date has passed, you must demonstrate compliance within 60 days of the effective date of the waste-to-fuel switch. If you have not conducted your compliance demonstration for this subpart within the previous 12 months, you must complete all compliance demonstrations for this subpart before you commence or recommence combustion of solid waste.

§ 63.7515 When must I conduct subsequent performance tests, fuel analyses, or tune-ups?

(a) You must conduct all applicable performance tests according to § 63.7520 on an annual basis, except those for dioxin/furan emissions, unless you follow the requirements listed in paragraphs (b) through (e) of this section. Annual performance tests must be completed no more than 13 months after the previous performance test, unless you follow the requirements listed in paragraphs (b) through (e) of this section. Annual performance testing for dioxin/furan emissions is not required after the initial compliance demonstration.

(b) You can conduct performance tests less often for a given pollutant if your performance tests for the pollutant for at least 2 consecutive years show that your emissions are at or below 75 percent of the emission limit, and if there are no changes in the operation of the affected source or air pollution control equipment that could increase emissions. In this case, you do not have to conduct a performance test for that pollutant for the next 2 years. You must conduct a performance test during the third year and no more than 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under § 63.7522, you must continue to conduct performance tests annually.

(c) If your boiler or process heater continues to meet the emission limit for the pollutant, you may choose to conduct performance tests for the pollutant every third year if your emissions are at or below 75 percent of the emission limit, and if there are no changes in the operation of the affected source or air pollution control equipment that could increase emissions, but each such performance test must be conducted no more than 37 months after the previous performance test. If you elect to demonstrate compliance using emission averaging under § 63.7522, you must continue to conduct performance tests annually. The requirement to test at maximum chloride input level is waived unless the stack test is conducted for HCl. The requirement to test at maximum Hg input level is waived unless the stack test is conducted for Hg.

(d) If a performance test shows emissions exceeded 75 percent of the emission limit for a pollutant, you must conduct annual performance tests for that pollutant until all performance tests over a consecutive 2-year period show compliance.

(e) If you are required to meet an applicable tune-up work practice standard, you must conduct an annual or biennial performance tune-up according to § 63.7540(a)(10) and (a)(11), respectively. Each annual tune-up specified in § 63.7540(a)(10) must be no more than 13 months after the previous tune-up. Each biennial tune-up specified in § 63.7540(a)(11) must be conducted no more than 25 months after the previous tune-up.

(f) If you demonstrate compliance with the mercury or hydrogen chloride based on fuel analysis, you must conduct a monthly fuel analysis according to § 63.7521 for each type of fuel burned that is subject to an emission limit in Table 1, 2, or 12 of this subpart. If you burn a new type of fuel, you must conduct a fuel analysis before burning the new type of fuel in your boiler or process heater. You must still meet all applicable continuous compliance requirements in § 63.7540. If 12 consecutive monthly fuel analyses demonstrate compliance, you may request decreased fuel analysis frequency by applying to the EPA Administrator for approval of alternative monitoring under § 63.8(f).

(g) You must report the results of performance tests and the associated initial fuel analyses within 90 days after the completion of the performance tests. This report must also verify that the operating limits for your affected source have not changed or provide documentation of revised operating parameters established according to § 63.7530 and Table 7 to this subpart, as applicable. The reports for all subsequent performance tests must include all applicable information required in § 63.7550.

§ 63.7520 What stack tests and procedures must I use?

(a) You must conduct all performance tests according to § 63.7(c), (d), (f), and (h). You must also develop a site-specific stack test plan according to the requirements in § 63.7(c). You shall conduct all performance tests under such conditions as the Administrator specifies to you based on representative performance of the affected source for the period being tested. Upon request, you shall make available to the Administrator such records as may be necessary to determine the conditions of the performance tests.

(b) You must conduct each performance test according to the requirements in Table 5 to this subpart.

(c) You must conduct each performance test under the specific conditions listed in Tables 5 and 7 to this subpart. You must conduct performance tests at representative operating load conditions while burning the type of fuel or mixture of fuels that has the highest content of chlorine and mercury, and you must demonstrate initial compliance and establish your operating limits based on these performance tests. These requirements could result in the need to conduct more than one performance test. Following each performance test and until the next performance test, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(d) You must conduct three separate test runs for each performance test required in this section, as specified in § 63.7(e)(3). Each test run must comply with the minimum applicable sampling times or volumes specified in Tables 1, 2, and 12 to this subpart.

(e) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 at 40 CFR part 60, appendix A–7 of this chapter to convert the measured particulate matter concentrations, the measured hydrogen chloride concentrations, and the measured mercury concentrations that result from the initial performance test to pounds per million Btu heat input emission rates using F-factors.

§ 63.7521 What fuel analyses, fuel specification, and procedures must I use?

(a) For solid, liquid, and gas 2 (other) fuels, you must conduct fuel analyses for chloride and mercury according to the procedures in paragraphs (b) through (e) of this section and Table 6 to this subpart, as applicable. You are not required to conduct fuel analyses for fuels used for only startup, unit shutdown, and transient flame stability purposes. You are required to conduct fuel analyses only for fuels and units that are subject to emission limits for mercury and hydrogen chloride in Tables 1, 2, or 12 to this subpart. Gaseous and liquid fuels are exempt from requirements in paragraphs (c) and (d) of this section and Table 6 of this subpart.

(b) You must develop and submit a site-specific fuel monitoring plan to the EPA Administrator for review and approval according to the following procedures and requirements in paragraphs (b)(1) and (2) of this section.

(1) You must submit the fuel analysis plan no later than 60 days before the date that you intend to conduct an initial compliance demonstration.

(2) You must include the information contained in paragraphs (b)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all fuel types anticipated to be burned in each boiler or process heater.

(ii) For each fuel type, the notification of whether you or a fuel supplier will be conducting the fuel analysis.

(iii) For each fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the composite samples if your procedures are different from paragraph (c) or (d) of this section. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types.

(iv) For each fuel type, the analytical methods from Table 6, with the expected minimum detection levels, to be used for the measurement of chlorine or mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

(c) At a minimum, you must obtain three composite fuel samples for each fuel type according to the procedures in paragraph (c)(1) or (2) of this section.

(1) If sampling from a belt (or screw) feeder, collect fuel samples according to paragraphs (c)(1)(i) and (ii) of this section.

(i) Stop the belt and withdraw a 6-inch wide sample from the full cross-section of the stopped belt to obtain a minimum two pounds of sample. You must collect all the material (fines and coarse) in the full cross-section. You must transfer the sample to a clean plastic bag.

(ii) Each composite sample will consist of a minimum of three samples collected at approximately equal 1-hour intervals during the testing period.

(2) If sampling from a fuel pile or truck, you must collect fuel samples according to paragraphs (c)(2)(i) through (iii) of this section.

(i) For each composite sample, you must select a minimum of five sampling locations uniformly spaced over the surface of the pile.

(ii) At each sampling site, you must dig into the pile to a depth of 18 inches. You must insert a clean flat square shovel into the hole and withdraw a sample, making sure that large pieces do not fall off during sampling.

(iii) You must transfer all samples to a clean plastic bag for further processing.

(d) You must prepare each composite sample according to the procedures in paragraphs (d)(1) through (7) of this section.

(1) You must thoroughly mix and pour the entire composite sample over a clean plastic sheet.

(2) You must break sample pieces larger than 3 inches into smaller sizes.

(3) You must make a pie shape with the entire composite sample and subdivide it into four equal parts.

(4) You must separate one of the quarter samples as the first subset.

(5) If this subset is too large for grinding, you must repeat the procedure in paragraph (d)(3) of this section with the quarter sample and obtain a one-quarter subset from this sample.

(6) You must grind the sample in a mill.

(7) You must use the procedure in paragraph (d)(3) of this section to obtain a one-quarter subsample for analysis. If the quarter sample is too large, subdivide it further using the same procedure.

(e) You must determine the concentration of pollutants in the fuel (mercury and/or chlorine) in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 6 to this subpart.

(f) To demonstrate that a gaseous fuel other than natural gas or refinery gas qualifies as an other gas 1 fuel, as defined in § 63.7575, you must conduct a fuel specification analyses for hydrogen sulfide and mercury according to the procedures in paragraphs (g) through (i) of this section and Table 6 to this subpart, as applicable. You are not required to conduct the fuel specification analyses in paragraphs (g) through (i) of this section for gaseous fuels other than natural gas or refinery gas that are complying with the limits for units designed to burn gas 2 (other) fuels.

(g) You must develop and submit a site-specific fuel analysis plan for other gas 1 fuels to the EPA Administrator for review and approval according to the following procedures and requirements in paragraphs (g)(1) and (2) of this section.

(1) You must submit the fuel analysis plan no later than 60 days before the date that you intend to conduct an initial compliance demonstration.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vi) of this section in your fuel analysis plan.

(i) The identification of all gaseous fuel types other than natural gas or refinery gas anticipated to be burned in each boiler or process heater.

(ii) For each fuel type, the notification of whether you or a fuel supplier will be conducting the fuel specification analysis.

(iii) For each fuel type, a detailed description of the sample location and specific procedures to be used for collecting and preparing the samples if your procedures are different from the sampling methods contained in Table 6. Samples should be collected at a location that most accurately represents the fuel type, where possible, at a point prior to mixing with other dissimilar fuel types. If multiple boilers or process heaters are fueled by a common fuel stream it is permissible to conduct a single gas specification at the common point of gas distribution.

(iv) For each fuel type, the analytical methods from Table 6, with the expected minimum detection levels, to be used for the measurement of hydrogen sulfide and mercury.

(v) If you request to use an alternative analytical method other than those required by Table 6 to this subpart, you must also include a detailed description of the methods and procedures that you are proposing to use. Methods in Table 6 shall be used until the requested alternative is approved.

(vi) If you will be using fuel analysis from a fuel supplier in lieu of site-specific sampling and analysis, the fuel supplier must use the analytical methods required by Table 6 to this subpart.

(h) You must obtain a single fuel sample for each other gas 1 fuel type according to the sampling procedures listed in Table 6 for fuel specification of gaseous fuels.

(i) You must determine the concentration in the fuel of mercury, in units of microgram per cubic meter, and of hydrogen sulfide, in units of parts per million, by volume, dry basis, of each sample for each gas 1 fuel type according to the procedures in Table 6 to this subpart.

§ 63.7522 Can I use emissions averaging to comply with this subpart?

(a) As an alternative to meeting the requirements of § 63.7500 for particulate matter, hydrogen chloride, or mercury on a boiler or process heater-specific basis, if you have more than one existing boiler or process heater in any subcategory located at your facility, you may demonstrate compliance by emissions averaging, if your averaged emissions are not more than 90 percent of the applicable emission limit, according to the procedures in this section. You may not include new boilers or process heaters in an emissions average.

(b) For a group of two or more existing boilers or process heaters in the same subcategory that each vent to a separate stack, you may average particulate matter, hydrogen chloride, or mercury emissions among existing units to demonstrate compliance with the limits in Table 2 to this subpart if you satisfy the requirements in paragraphs (c), (d), (e), (f), and (g) of this section.

(c) For each existing boiler or process heater in the averaging group, the emission rate achieved during the initial compliance test for the HAP being averaged must not exceed the emission level that was being achieved on May 20, 2011 or the control technology employed during the initial compliance test must not be less effective for the HAP being averaged than the control technology employed on May 20, 2011.

(d) The averaged emissions rate from the existing boilers and process heaters participating in the emissions averaging option must be in compliance with the limits in Table 2 to this subpart at all times following the compliance date specified in § 63.7495.

(e) You must demonstrate initial compliance according to paragraph (e)(1) or (2) of this section using the maximum rated heat input capacity or maximum steam generation capacity of each unit and the results of the initial performance tests or fuel analysis.

(1) You must use Equation 1 of this section to demonstrate that the particulate matter, hydrogen chloride, or mercury emissions from all existing units participating in the emissions averaging option for that pollutant do not exceed the emission limits in Table 2 to this subpart.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Hm) \div \sum_{i=1}^{n} Hm \qquad \text{(Eq. 1)}$$

Where:

AveWeightedEmissions = Average weighted emissions for particulate matter, hydrogen chloride, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the initial compliance demonstration) of particulate matter, hydrogen chloride, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for particulate matter, hydrogen chloride, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for hydrogen chloride or mercury using the applicable equation in § 63.7530(c).

Hm = Maximum rated heat input capacity of unit, i, in units of million Btu per hour.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

(2) If you are not capable of determining the maximum rated heat input capacity of one or more boilers that generate steam, you may use Equation 2 of this section as an alternative to using Equation 1 of this section to demonstrate that the particulate matter, hydrogen chloride, or mercury emissions from all existing units participating in the emissions averaging option do not exceed the emission limits for that pollutant in Table 2 to this subpart.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Sm \times Cfi) \div \sum_{i=1}^{n} (Sm \times Cfi) \qquad \text{(Eq. 2)}$$

Where:

AveWeightedEmissions = Average weighted emission level for PM, hydrogen chloride, or mercury, in units of pounds per million Btu of heat input.

Er = Emission rate (as determined during the most recent compliance demonstration) of particulate matter, hydrogen chloride, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for particulate matter, hydrogen chloride, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for hydrogen chloride or mercury using the applicable equation in § 63.7530(c).

Sm = Maximum steam generation capacity by unit, i, in units of pounds.

Cfi = Conversion factor, calculated from the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for unit, i.

1.1 = Required discount factor.

(f) After the initial compliance demonstration described in paragraph (e) of this section, you must demonstrate compliance on a monthly basis determined at the end of every month (12 times per year) according to paragraphs (f)(1) through (3) of this section. The first monthly period begins on the compliance date specified in § 63.7495.

(1) For each calendar month, you must use Equation 3 of this section to calculate the average weighted emission rate for that month using the actual heat input for each existing unit participating in the emissions averaging option.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Hb) \div \sum_{i=1}^{n} Hb \qquad \text{(Eq. 3)}$$

Where:

AveWeightedEmissions = Average weighted emission level for particulate matter, hydrogen chloride, or mercury, in units of pounds per million Btu of heat input, for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration) of particulate matter, hydrogen chloride, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for particulate matter, hydrogen chloride, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for hydrogen chloride or mercury using the applicable equation in § 63.7530(c).

Hb = The heat input for that calendar month to unit, i, in units of million Btu.

n = Number of units participating in the emissions averaging option.

1.1 = Required discount factor.

(2) If you are not capable of monitoring heat input, you may use Equation 4 of this section as an alternative to using Equation 3 of this section to calculate the average weighted emission rate using the actual steam generation from the boilers participating in the emissions averaging option.

$$AveWeightedEmissions = 1.1 \times \sum_{i=1}^{n} (Er \times Sa \times Cfi) \div \sum_{i=1}^{n} (Sa \times Cfi) \qquad \text{(Eq. 4)}$$

Where:

AveWeightedEmissions = average weighted emission level for PM, hydrogen chloride, or mercury, in units of pounds per million Btu of heat input for that calendar month.

Er = Emission rate (as determined during the most recent compliance demonstration of particulate matter, hydrogen chloride, or mercury from unit, i, in units of pounds per million Btu of heat input. Determine the emission rate for particulate matter, hydrogen chloride, or mercury by performance testing according to Table 5 to this subpart, or by fuel analysis for hydrogen chloride or mercury using the applicable equation in § 63.7530(c).

Sa = Actual steam generation for that calendar month by boiler, i, in units of pounds.

Cfi = Conversion factor, as calculated during the most recent compliance test, in units of million Btu of heat input per pounds of steam generated for boiler, i.

1.1 = Required discount factor.

(3) Until 12 monthly weighted average emission rates have been accumulated, calculate and report only the average weighted emission rate determined under paragraph (f)(1) or (2) of this section for each calendar month. After 12 monthly weighted average emission rates have been accumulated, for each subsequent calendar month, use Equation 5 of this section to calculate the 12-month rolling average of the monthly weighted average emission rates for the current calendar month and the previous 11 calendar months.

$$Eavg = \sum_{i=1}^{n} ERi \div 12 \qquad \text{(Eq. 5)}$$

Where:

Eavg = 12-month rolling average emission rate, (pounds per million Btu heat input)

ERi = Monthly weighted average, for calendar month "i" (pounds per million Btu heat input), as calculated by paragraph (f)(1) or (2) of this section.

(g) You must develop, and submit to the applicable delegated authority for review and approval, an implementation plan for emission averaging according to the following procedures and requirements in paragraphs (g)(1) through (4) of this section.

(1) You must submit the implementation plan no later than 180 days before the date that the facility intends to demonstrate compliance using the emission averaging option.

(2) You must include the information contained in paragraphs (g)(2)(i) through (vii) of this section in your implementation plan for all emission sources included in an emissions average:

(i) The identification of all existing boilers and process heaters in the averaging group, including for each either the applicable HAP emission level or the control technology installed as of May 20, 2011 and the date on which you are requesting emission averaging to commence;

(ii) The process parameter (heat input or steam generated) that will be monitored for each averaging group;

(iii) The specific control technology or pollution prevention measure to be used for each emission boiler or process heater in the averaging group and the date of its installation or application. If the pollution prevention measure reduces or eliminates emissions from multiple boilers or process heaters, the owner or operator must identify each boiler or process heater;

(iv) The test plan for the measurement of particulate matter, hydrogen chloride, or mercury emissions in accordance with the requirements in § 63.7520;

(v) The operating parameters to be monitored for each control system or device consistent with § 63.7500 and Table 4, and a description of how the operating limits will be determined;

(vi) If you request to monitor an alternative operating parameter pursuant to § 63.7525, you must also include:

(A) A description of the parameter(s) to be monitored and an explanation of the criteria used to select the parameter(s); and

(B) A description of the methods and procedures that will be used to demonstrate that the parameter indicates proper operation of the control device; the frequency and content of monitoring, reporting, and recordkeeping requirements; and a demonstration, to the satisfaction of the applicable delegated authority, that the proposed monitoring frequency is sufficient to represent control device operating conditions; and

(vii) A demonstration that compliance with each of the applicable emission limit(s) will be achieved under representative operating load conditions. Following each compliance demonstration and until the next compliance demonstration, you must comply with the operating limit for operating load conditions specified in Table 4 to this subpart.

(3) The delegated authority shall review and approve or disapprove the plan according to the following criteria:

(i) Whether the content of the plan includes all of the information specified in paragraph (g)(2) of this section; and

(ii) Whether the plan presents sufficient information to determine that compliance will be achieved and maintained.

(4) The applicable delegated authority shall not approve an emission averaging implementation plan containing any of the following provisions:

(i) Any averaging between emissions of differing pollutants or between differing sources; or

(ii) The inclusion of any emission source other than an existing unit in the same subcategory.

(h) For a group of two or more existing affected units, each of which vents through a single common stack, you may average particulate matter, hydrogen chloride, or mercury emissions to demonstrate compliance with the limits for that pollutant in Table 2 to this subpart if you satisfy the requirements in paragraph (i) or (j) of this section.

(i) For a group of two or more existing units in the same subcategory, each of which vents through a common emissions control system to a common stack, that does not receive emissions from units in other subcategories or categories, you may treat such averaging group as a single existing unit for purposes of this subpart and comply with the requirements of this subpart as if the group were a single unit.

(j) For all other groups of units subject to the common stack requirements of paragraph (h) of this section, including situations where the exhaust of affected units are each individually controlled and then sent to a common stack, the owner or operator may elect to:

(1) Conduct performance tests according to procedures specified in § 63.7520 in the common stack if affected units from other subcategories vent to the common stack. The emission limits that the group must comply with are determined by the use of Equation 6 of this section.

$$En = \sum_{i=1}^{n}(ELi \times Hi) \div \sum_{i=1}^{n} Hi \quad \text{(Eq. 6)}$$

Where:

En = HAP emission limit, pounds per million British thermal units (lb/MMBtu), parts per million (ppm), or nanograms per dry standard cubic meter (ng/dscm).

ELi = Appropriate emission limit from Table 2 to this subpart for unit i, in units of lb/MMBtu, ppm or ng/dscm.

Hi = Heat input from unit i, MMBtu.

(2) Conduct performance tests according to procedures specified in § 63.7520 in the common stack. If affected units and non-affected units vent to the common stack, the non-affected units must be shut down or vented to a different stack during the performance test unless the facility determines to demonstrate compliance with the non-affected units venting to the stack; and

(3) Meet the applicable operating limit specified in § 63.7540 and Table 8 to this subpart for each emissions control system (except that, if each unit venting to the common stack has an applicable opacity operating limit, then a single continuous opacity monitoring system may be located in the common stack instead of in each duct to the common stack).

(k) The common stack of a group of two or more existing boilers or process heaters in the same subcategory subject to paragraph (h) of this section may be treated as a separate stack for purposes of paragraph (b) of this section and included in an emissions averaging group subject to paragraph (b) of this section.

§ 63.7525 What are my monitoring, installation, operation, and maintenance requirements?

(a) If your boiler or process heater is subject to a carbon monoxide emission limit in Table 1, 2, or 12 to this subpart, you must install, operate, and maintain a continuous oxygen monitor according to the procedures in paragraphs (a)(1) through (6) of this section by the compliance date specified in § 63.7495. The oxygen level shall be monitored at the outlet of the boiler or process heater.

(1) Each CEMS for oxygen (O_2 CEMS) must be installed, operated, and maintained according to the applicable procedures under Performance Specification 3 at 40 CFR part 60, appendix B, and according to the site-specific monitoring plan developed according to § 63.7505(d).

(2) You must conduct a performance evaluation of each O_2 CEMS according

to the requirements in § 63.8(e) and according to Performance Specification 3 at 40 CFR part 60, appendix B.

(3) Each O_2 CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(4) The O_2 CEMS data must be reduced as specified in § 63.8(g)(2).

(5) You must calculate and record 12-hour block average concentrations for each operating day.

(6) For purposes of calculating data averages, you must use all the data collected during all periods in assessing compliance, excluding data collected during periods when the monitoring system malfunctions or is out of control, during associated repairs, and during required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments). Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. Any period for which the monitoring system malfunctions or is out of control and data are not available for a required calculation constitutes a deviation from the monitoring requirements. Periods when data are unavailable because of required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments) do not constitute monitoring deviations.

(b) If your boiler or process heater has a heat input capacity of greater than 250 MMBtu per hour and combusts coal, biomass, or residual oil, you must install, certify, maintain, and operate a CEMS measuring PM emissions discharged to the atmosphere and record the output of the system as specified in paragraphs (b)(1) through (5) of this section.

(1) Each CEMS shall be installed, certified, operated, and maintained according to the requirements in § 63.7540(a)(9).

(2) For a new unit, the initial performance evaluation shall be completed no later than November 16, 2011 or 180 days after the date of initial startup, whichever is later. For an existing unit, the initial performance evaluation shall be completed no later than September 17, 2014.

(3) Compliance with the applicable emissions limit shall be determined based on the 30-day rolling average of the hourly arithmetic average emissions concentrations using the continuous monitoring system outlet data. The 30-day rolling arithmetic average emission concentration shall be calculated using EPA Reference Method 19 at 40 CFR part 60, appendixA–7.

(4) Collect CEMS hourly averages for all operating hours on a 30-day rolling average basis. Collect at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

(5) The 1-hour arithmetic averages required shall be expressed in lb/MMBtu and shall be used to calculate the boiler operating day daily arithmetic average emissions.

(c) If you have an applicable opacity operating limit in this rule, and are not otherwise required to install and operate a PM CEMS or a bag leak detection system, you must install, operate, certify and maintain each COMS according to the procedures in paragraphs (c)(1) through (7) of this section by the compliance date specified in § 63.7495.

(1) Each COMS must be installed, operated, and maintained according to Performance Specification 1 at appendix B to part 60 of this chapter.

(2) You must conduct a performance evaluation of each COMS according to the requirements in § 63.8(e) and according to Performance Specification 1 at appendix B to part 60 of this chapter.

(3) As specified in § 63.8(c)(4)(i), each COMS must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(4) The COMS data must be reduced as specified in § 63.8(g)(2).

(5) You must include in your site-specific monitoring plan procedures and acceptance criteria for operating and maintaining each COMS according to the requirements in § 63.8(d). At a minimum, the monitoring plan must include a daily calibration drift assessment, a quarterly performance audit, and an annual zero alignment audit of each COMS.

(6) You must operate and maintain each COMS according to the requirements in the monitoring plan and the requirements of § 63.8(e). You must identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit. Any 6-minute period for which the monitoring system is out of control and data are not available for a required calculation constitutes a deviation from the monitoring requirements.

(7) You must determine and record all the 6-minute averages (and daily block averages as applicable) collected for periods during which the COMS is not out of control.

(d) If you have an operating limit that requires the use of a CMS, you must install, operate, and maintain each continuous parameter monitoring system according to the procedures in paragraphs (d)(1) through (5) of this section by the compliance date specified in § 63.7495.

(1) The continuous parameter monitoring system must complete a minimum of one cycle of operation for each successive 15-minute period. You must have a minimum of four successive cycles of operation to have a valid hour of data.

(2) Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must conduct all monitoring in continuous operation at all times that the unit is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(3) For purposes of calculating data averages, you must not use data recorded during monitoring malfunctions, associated repairs, out of control periods, or required quality assurance or control activities. You must use all the data collected during all other periods in assessing compliance. Any 15-minute period for which the monitoring system is out-of-control and data are not available for a required calculation constitutes a deviation from the monitoring requirements.

(4) You must determine the 4-hour block average of all recorded readings, except as provided in paragraph (d)(3) of this section.

(5) You must record the results of each inspection, calibration, and validation check.

(e) If you have an operating limit that requires the use of a flow monitoring system, you must meet the requirements in paragraphs (d) and (e)(1) through (4) of this section.

(1) You must install the flow sensor and other necessary equipment in a position that provides a representative flow.

(2) You must use a flow sensor with a measurement sensitivity of no greater than 2 percent of the expected flow rate.

(3) You must minimize the effects of swirling flow or abnormal velocity distributions due to upstream and downstream disturbances.

(4) You must conduct a flow monitoring system performance evaluation in accordance with your monitoring plan at the time of each performance test but no less frequently than annually. (f) If you have an operating limit that requires the use of a pressure monitoring system, you must meet the requirements in paragraphs (d) and (f)(1) through (6) of this section.

(1) Install the pressure sensor(s) in a position that provides a representative measurement of the pressure (*e.g.*, PM scrubber pressure drop).

(2) Minimize or eliminate pulsating pressure, vibration, and internal and external corrosion.

(3) Use a pressure sensor with a minimum tolerance of 1.27 centimeters of water or a minimum tolerance of 1 percent of the pressure monitoring system operating range, whichever is less.

(4) Perform checks at least once each process operating day to ensure pressure measurements are not obstructed (*e.g.*, check for pressure tap pluggage daily).

(5) Conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(6) If at any time the measured pressure exceeds the manufacturer's specified maximum operating pressure range, conduct a performance evaluation of the pressure monitoring system in accordance with your monitoring plan and confirm that the pressure monitoring system continues to meet the performance requirements in you monitoring plan. Alternatively, install and verify the operation of a new pressure sensor.

(g) If you have an operating limit that requires a pH monitoring system, you must meet the requirements in paragraphs (d) and (g)(1) through (4) of this section.

(1) Install the pH sensor in a position that provides a representative measurement of scrubber effluent pH.

(2) Ensure the sample is properly mixed and representative of the fluid to be measured.

(3) Conduct a performance evaluation of the pH monitoring system in accordance with your monitoring plan at least once each process operating day.

(4) Conduct a performance evaluation (including a two-point calibration with one of the two buffer solutions having a pH within 1 of the pH of the operating limit) of the pH monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than quarterly.

(h) If you have an operating limit that requires a secondary electric power monitoring system for an electrostatic precipitator (ESP) operated with a wet scrubber, you must meet the requirements in paragraphs (h)(1) and (2) of this section.

(1) Install sensors to measure (secondary) voltage and current to the precipitator collection plates.

(2) Conduct a performance evaluation of the electric power monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(i) If you have an operating limit that requires the use of a monitoring system to measure sorbent injection rate (e.g., weigh belt, weigh hopper, or hopper flow measurement device), you must meet the requirements in paragraphs (d) and (i)(1) through (2) of this section.

(1) Install the system in a position(s) that provides a representative measurement of the total sorbent injection rate.

(2) Conduct a performance evaluation of the sorbent injection rate monitoring system in accordance with your monitoring plan at the time of each performance test but no less frequently than annually.

(j) If you are not required to use a PM CEMS and elect to use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate the bag leak detection system as specified in paragraphs (j)(1) through (7) of this section.

(1) You must install a bag leak detection sensor(s) in a position(s) that will be representative of the relative or absolute particulate matter loadings for each exhaust stack, roof vent, or compartment (*e.g.*, for a positive pressure fabric filter) of the fabric filter.

(2) Conduct a performance evaluation of the bag leak detection system in accordance with your monitoring plan and consistent with the guidance provided in EPA–454/R–98–015 (incorporated by reference, *see* § 63.14).

(3) Use a bag leak detection system certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 10 milligrams per actual cubic meter or less.

(4) Use a bag leak detection system equipped with a device to record continuously the output signal from the sensor.

(5) Use a bag leak detection system equipped with a system that will alert when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it can be easily heard or seen by plant operating personnel.

(7) Where multiple bag leak detectors are required, the system's instrumentation and alarm may be shared among detectors.

(k) For each unit that meets the definition of limited-use boiler or process heater, you must monitor and record the operating hours per year for that unit.

§ 63.7530 How do I demonstrate initial compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate initial compliance with each emission limit that applies to you by conducting initial performance tests and fuel analyses and establishing operating limits, as applicable, according to § 63.7520, paragraphs (b) and (c) of this section, and Tables 5 and 7 to this subpart. If applicable, you must also install, and operate, maintain all applicable CMS (including CEMS, COMS, and continuous parameter monitoring systems) according to § 63.7525.

(b) If you demonstrate compliance through performance testing, you must establish each site-specific operating limit in Table 4 to this subpart that applies to you according to the requirements in § 63.7520, Table 7 to this subpart, and paragraph (b)(3) of this section, as applicable. You must also conduct fuel analyses according to § 63.7521 and establish maximum fuel pollutant input levels according to paragraphs (b)(1) and (2) of this section, as applicable. As specified in § 63.7510(a), if your affected source burns a single type of fuel (excluding supplemental fuels used for unit startup, shutdown, or transient flame stabilization), you are not required to perform the initial fuel analysis for each type of fuel burned in your boiler or process heater. However, if you switch fuel(s) and cannot show that the new fuel(s) do (does) not increase the chlorine or mercury input into the unit through the results of fuel analysis, then you must repeat the performance test to demonstrate compliance while burning the new fuel(s).

(1) You must establish the maximum chlorine fuel input (Clinput) during the initial fuel analysis according to the procedures in paragraphs (b)(1)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of chlorine.

(ii) During the fuel analysis for hydrogen chloride, you must determine the fraction of the total heat input for each fuel type burned (Qi) based on the fuel mixture that has the highest content of chlorine, and the average chlorine concentration of each fuel type burned (Ci).

(iii) You must establish a maximum chlorine input level using Equation 7 of this section.

$$Clinput = \sum_{i=1}^{n} (Ci \times Qi) \quad \text{(Eq. 7)}$$

Where:

Clinput = Maximum amount of chlorine entering the boiler or process heater through fuels burned in units of pounds per million Btu.

Ci = Arithmetic average concentration of chlorine in fuel type, i, analyzed according to § 63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types during the performance testing, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

(2) You must establish the maximum mercury fuel input level (Mercuryinput) during the initial fuel analysis using the procedures in paragraphs (b)(2)(i) through (iii) of this section.

(i) You must determine the fuel type or fuel mixture that you could burn in your boiler or process heater that has the highest content of mercury.

(ii) During the compliance demonstration for mercury, you must determine the fraction of total heat input for each fuel burned (Qi) based on the fuel mixture that has the highest content of mercury, and the average mercury concentration of each fuel type burned (HGi).

(iii) You must establish a maximum mercury input level using Equation 8 of this section.

$$Mercuryinput = \sum_{i=1}^{n} (HGi \times Qi) \quad \text{(Eq. 8)}$$

Where:

Mercuryinput = Maximum amount of mercury entering the boiler or process heater through fuels burned in units of pounds per million Btu.

HGi = Arithmetic average concentration of mercury in fuel type, i, analyzed according to § 63.7521, in units of pounds per million Btu.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types during the performance test, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of mercury.

(3) You must establish parameter operating limits according to paragraphs (b)(3)(i) through (iv) of this section.

(i) For a wet scrubber, you must establish the minimum scrubber effluent pH, liquid flowrate, and pressure drop as defined in § 63.7575, as your operating limits during the three-run performance test. If you use a wet scrubber and you conduct separate performance tests for particulate matter, hydrogen chloride, and mercury emissions, you must establish one set of minimum scrubber effluent pH, liquid flowrate, and pressure drop operating limits. The minimum scrubber effluent pH operating limit must be established during the hydrogen chloride performance test. If you conduct multiple performance tests, you must set the minimum liquid flowrate and pressure drop operating limits at the highest minimum values established during the performance tests.

(ii) For an electrostatic precipitator operated with a wet scrubber, you must establish the minimum voltage and secondary amperage (or total power input), as defined in § 63.7575, as your operating limits during the three-run performance test. (These operating limits do not apply to electrostatic precipitators that are operated as dry controls without a wet scrubber.)

(iii) For a dry scrubber, you must establish the minimum sorbent injection rate for each sorbent, as defined in § 63.7575, as your operating limit during the three-run performance test.

(iv) For activated carbon injection, you must establish the minimum activated carbon injection rate, as defined in § 63.7575, as your operating limit during the three-run performance test.

(v) The operating limit for boilers or process heaters with fabric filters that demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in § 63.7525, and that each fabric filter must be operated such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during a 6-month period.

(c) If you elect to demonstrate compliance with an applicable emission limit through fuel analysis, you must conduct fuel analyses according to § 63.7521 and follow the procedures in paragraphs (c)(1) through (4) of this section.

(1) If you burn more than one fuel type, you must determine the fuel mixture you could burn in your boiler or process heater that would result in the maximum emission rates of the pollutants that you elect to demonstrate compliance through fuel analysis.

(2) You must determine the 90th percentile confidence level fuel pollutant concentration of the composite samples analyzed for each fuel type using the one-sided z-statistic test described in Equation 9 of this section.

$$P90 = mean + (SD \times t) \quad \text{(Eq. 9)}$$

Where:

P90 = 90th percentile confidence level pollutant concentration, in pounds per million Btu.

Mean = Arithmetic average of the fuel pollutant concentration in the fuel samples analyzed according to § 63.7521, in units of pounds per million Btu.

SD = Standard deviation of the pollutant concentration in the fuel samples analyzed according to § 63.7521, in units of pounds per million Btu.

T = t distribution critical value for 90th percentile (0.1) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a Distribution Critical Value Table.

(3) To demonstrate compliance with the applicable emission limit for hydrogen chloride, the hydrogen chloride emission rate that you calculate for your boiler or process heater using Equation 10 of this section must not exceed the applicable emission limit for hydrogen chloride.

$$HCl = \sum_{i=1}^{n}(Ci90 \times Qi \times 1.028) \qquad \text{(Eq. 10)}$$

Where:

HCl = Hydrogen chloride emission rate from the boiler or process heater in units of pounds per million Btu.

Ci90 = 90th percentile confidence level concentration of chlorine in fuel type, i, in units of pounds per million Btu as calculated according to Equation 9 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest content of chlorine. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest content of chlorine.

1.028 = Molecular weight ratio of hydrogen chloride to chlorine.

(4) To demonstrate compliance with the applicable emission limit for mercury, the mercury emission rate that you calculate for your boiler or process heater using Equation 11 of this section must not exceed the applicable emission limit for mercury.

$$Mercury = \sum_{i=1}^{n}(Hgi90 \times Qi) \qquad \text{(Eq. 11)}$$

Where:

Mercury = Mercury emission rate from the boiler or process heater in units of pounds per million Btu.

Hgi90 = 90th percentile confidence level concentration of mercury in fuel, i, in units of pounds per million Btu as calculated according to Equation 9 of this section.

Qi = Fraction of total heat input from fuel type, i, based on the fuel mixture that has the highest mercury content. If you do not burn multiple fuel types, it is not necessary to determine the value of this term. Insert a value of "1" for Qi.

n = Number of different fuel types burned in your boiler or process heater for the mixture that has the highest mercury content.

(d) If you own or operate an existing unit with a heat input capacity of less than 10 million Btu per hour, you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted a tune-up of the unit.

(e) You must include with the Notification of Compliance Status a signed certification that the energy assessment was completed according to Table 3 to this subpart and is an accurate depiction of your facility.

(f) You must submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.7545(e).

(g) If you elect to demonstrate that a gaseous fuel meets the specifications of an other gas 1 fuel as defined in § 63.7575, you must conduct an initial fuel specification analyses according to § 63.7521(f) through (i). If the mercury and hydrogen sulfide constituents in the gaseous fuels will never exceed the specifications included in the definition, you will include a signed certification with the Notification of Compliance Status that the initial fuel specification test meets the gas specifications outlined in the definition of other gas 1 fuels. If your gas constituents could vary above the specifications, you will conduct monthly testing according to the procedures in § 63.7521(f) through (i) and § 63.7540(c) and maintain records of the results of the testing as outlined in § 63.7555(g).

(h) If you own or operate a unit subject emission limits in Tables 1, 2, or 12 of this subpart, you must minimize the unit's startup and shutdown periods following the manufacturer's recommended procedures, if available. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available. You must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a unit of similar design if manufacturer's recommended procedures are not available.

§ 63.7533 Can I use emission credits earned from implementation of energy conservation measures to comply with this subpart?

(a) If you elect to comply with the alternative equivalent steam output-based emission limits, instead of the heat input-based limits, listed in Tables 1 and 2 of this subpart and you want to take credit for implementing energy conservation measures identified in an energy assessment, you may demonstrate compliance using emission reduction credits according to the procedures in this section. Owners or operators using this compliance approach must establish an emissions benchmark, calculate and document the emission credits, develop an Implementation Plan, comply with the general reporting requirements, and apply the emission credit according to the procedures in paragraphs (b) through (f) of this section.

(b) For each existing affected boiler for which you intend to apply emissions credits, establish a benchmark from which emission reduction credits may be generated by determining the actual annual fuel heat input to the affected boiler before initiation of an energy conservation activity to reduce energy demand (*i.e.*, fuel usage) according to paragraphs (b)(1) through (4) of this section. The benchmark shall be expressed in trillion Btu per year heat input.

(1) The benchmark from which emission credits may be generated shall be determined by using the most representative, accurate, and reliable process available for the source. The benchmark shall be established for a one-year period before the date that an energy demand reduction occurs, unless it can be demonstrated that a different time period is more representative of historical operations.

(2) Determine the starting point from which to measure progress. Inventory all fuel purchased and generated on-site (off-gases, residues) in physical units (MMBtu, million cubic feet, etc.).

(3) Document all uses of energy from the affected boiler. Use the most recent data available.

(4) Collect non-energy related facility and operational data to normalize, if necessary, the benchmark to current operations, such as building size, operating hours, etc. Use actual, not estimated, use data, if possible and data that are current and timely.

(c) Emissions credits can be generated if the energy conservation measures were implemented after January 14, 2011 and if sufficient information is available to determine the appropriate value of credits.

(1) The following emission points cannot be used to generate emissions averaging credits:

(i) Energy conservation measures implemented on or before January 14, 2011, unless the level of energy demand reduction is increased after January 14, 2011, in which case credit will be allowed only for change in demand reduction achieved after January 14, 2011.

(ii) Emission credits on shut-down boilers. Boilers that are shut down cannot be used to generate credits.

(2) For all points included in calculating emissions credits, the owner or operator shall:

(i) Calculate annual credits for all energy demand points. Use Equation 12 to calculate credits. Energy conservation measures that meet the criteria of paragraph (c)(1) of this section shall not be included, except as specified in paragraph (c)(1)(i) of this section.

(3) Credits are generated by the difference between the benchmark that is established for each affected boiler, and the actual energy demand reductions from energy conservation measures implemented after January 14, 2011. Credits shall be calculated using Equation 12 of this section as follows:

(i) The overall equation for calculating credits is:

$$Credits = \sum_{i=1}^{n} EIS_{iactual} \div EI_{baseline} \quad \text{(Eq. 12)}$$

Where:

Credits = Energy Input Savings for all energy conservation measures implemented for an affected boiler, million Btu per year.

$EIS_{iactual}$ = Energy Input Savings for each energy conservation measure implemented for an affected boiler, million Btu per year.

$EI_{baseline}$ = Energy Input for the affected boiler, million Btu.

n = Number of energy conservation measures included in the emissions credit for the affected boiler.

(d) The owner or operator shall develop and submit for approval an Implementation Plan containing all of the information required in this paragraph for all boilers to be included in an emissions credit approach. The Implementation Plan shall identify all existing affected boilers to be included in applying the emissions credits. The Implementation Plan shall include a description of the energy conservation measures implemented and the energy savings generated from each measure and an explanation of the criteria used for determining that savings. You must submit the implementation plan for emission credits to the applicable delegated authority for review and approval no later than 180 days before the date on which the facility intends to demonstrate compliance using the emission credit approach.

(e) The emissions rate from each existing boiler participating in the emissions credit option must be in compliance with the limits in Table 2 to this subpart at all times following the compliance date specified in § 63.7495.

(f) You must demonstrate initial compliance according to paragraph (f)(1) or (2) of this section.

(1) You must use Equation 13 of this section to demonstrate that the emissions from the affected boiler participating in the emissions credit compliance approach do not exceed the emission limits in Table 2 to this subpart.

$$E_{adj} = E_m \times (1 - EC) \quad \text{(Eq. 13)}$$

Where:

E_{adj} = Emission level adjusted applying the emission credits earned, lb per million Btu steam output for the affected boiler.

E_m = Emissions measured during the performance test, lb per million Btu steam output for the affected boiler.

EC = Emission credits from equation 12 for the affected boiler.

Continuous Compliance Requirements

§ 63.7535 How do I monitor and collect data to demonstrate continuous compliance?

(a) You must monitor and collect data according to this section and the site-specific monitoring plan required by § 63.7505(d).

(b) You must operate the monitoring system and collect data at all required intervals at all times that the affected source is operating, except for periods of monitoring system malfunctions or out of control periods (*see* § 63.8(c)(7) of this part), and required monitoring system quality assurance or control activities, including, as applicable, calibration checks and required zero and span adjustments. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to effect monitoring system repairs in response to monitoring system malfunctions or out-of-control periods and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in data averages and calculations used to report emissions or operating levels. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments, failure to collect required data is a deviation of the monitoring requirements.

§ 63.7540 How do I demonstrate continuous compliance with the emission limitations, fuel specifications and work practice standards?

(a) You must demonstrate continuous compliance with each emission limit, operating limit, and work practice standard in Tables 1 through 3 to this subpart that applies to you according to the methods specified in Table 8 to this subpart and paragraphs (a)(1) through (11) of this section.

(1) Following the date on which the initial compliance demonstration is completed or is required to be completed under §§ 63.7 and 63.7510, whichever date comes first, operation above the established maximum or below the established minimum operating limits shall constitute a deviation of established operating limits listed in Table 4 of this subpart except during performance tests conducted to determine compliance with the emission limits or to establish new operating limits. Operating limits must

be confirmed or reestablished during performance tests.

(2) As specified in § 63.7550(c), you must keep records of the type and amount of all fuels burned in each boiler or process heater during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would either result in lower emissions of hydrogen chloride and mercury than the applicable emission limit for each pollutant (if you demonstrate compliance through fuel analysis), or result in lower fuel input of chlorine and mercury than the maximum values calculated during the last performance test (if you demonstrate compliance through performance testing).

(3) If you demonstrate compliance with an applicable hydrogen chloride emission limit through fuel analysis and you plan to burn a new type of fuel, you must recalculate the hydrogen chloride emission rate using Equation 9 of § 63.7530 according to paragraphs (a)(3)(i) through (iii) of this section.

(i) You must determine the chlorine concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of chlorine.

(iii) Recalculate the hydrogen chloride emission rate from your boiler or process heater under these new conditions using Equation 10 of § 63.7530. The recalculated hydrogen chloride emission rate must be less than the applicable emission limit.

(4) If you demonstrate compliance with an applicable hydrogen chloride emission limit through performance testing and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum chlorine input using Equation 7 of § 63.7530. If the results of recalculating the maximum chlorine input using Equation 7 of § 63.7530 are greater than the maximum chlorine input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.7520 to demonstrate that the hydrogen chloride emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b).

(5) If you demonstrate compliance with an applicable mercury emission limit through fuel analysis, and you plan to burn a new type of fuel, you must recalculate the mercury emission rate using Equation 11 of § 63.7530 according to the procedures specified in paragraphs (a)(5)(i) through (iii) of this section.

(i) You must determine the mercury concentration for any new fuel type in units of pounds per million Btu, based on supplier data or your own fuel analysis, according to the provisions in your site-specific fuel analysis plan developed according to § 63.7521(b).

(ii) You must determine the new mixture of fuels that will have the highest content of mercury.

(iii) Recalculate the mercury emission rate from your boiler or process heater under these new conditions using Equation 11 of § 63.7530. The recalculated mercury emission rate must be less than the applicable emission limit.

(6) If you demonstrate compliance with an applicable mercury emission limit through performance testing, and you plan to burn a new type of fuel or a new mixture of fuels, you must recalculate the maximum mercury input using Equation 8 of § 63.7530. If the results of recalculating the maximum mercury input using Equation 8 of § 63.7530 are higher than the maximum mercury input level established during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.7520 to demonstrate that the mercury emissions do not exceed the emission limit. You must also establish new operating limits based on this performance test according to the procedures in § 63.7530(b).

(7) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alarm and complete corrective actions as soon as practical, and operate and maintain the fabric filter system such that the alarm does not sound more than 5 percent of the operating time during a 6-month period. You must also keep records of the date, time, and duration of each alarm, the time corrective action was initiated and completed, and a brief description of the cause of the alarm and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the alarm sounds. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alarm time is counted. If corrective action is required, each alarm shall be counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alarm time shall be counted as the actual amount of time taken to initiate corrective action.

(8) [Reserved].

(9) The owner or operator of an affected source using a CEMS measuring PM emissions to meet requirements of this subpart shall install, certify, operate, and maintain the PM CEMS as specified in paragraphs (a)(9)(i) through (a)(9)(iv) of this section.

(i) The owner or operator shall conduct a performance evaluation of the PM CEMS according to the applicable requirements of § 60.13, and Performance Specification 11 at 40 CFR part 60, appendix B of this chapter.

(ii) During each PM correlation testing run of the CEMS required by Performance Specification 11 at 40 CFR part 60, appendix B of this chapter, PM and oxygen (or carbon dioxide) data shall be collected concurrently (or within a 30-to 60-minute period) by both the CEMS and conducting performance tests using Method 5 or 5B at 40 CFR part 60, appendix A–3 or Method 17 at 40 CFR part 60, appendix A–6 of this chapter.

(iii) Quarterly accuracy determinations and daily calibration drift tests shall be performed in accordance with Procedure 2 at 40 CFR part 60, appendix F of this chapter. Relative Response Audits must be performed annually and Response Correlation Audits must be performed every 3 years.

(iv) After December 31, 2011, within 60 days after the date of completing each CEMS relative accuracy test audit or performance test conducted to demonstrate compliance with this subpart, you must submit the relative accuracy test audit data and performance test data to EPA by successfully submitting the data electronically into EPA's Central Data Exchange by using the Electronic Reporting Tool (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*).

(10) If your boiler or process heater is in either the natural gas, refinery gas, other gas 1, or Metal Process Furnace subcategories and has a heat input capacity of 10 million Btu per hour or greater, you must conduct a tune-up of the boiler or process heater annually to demonstrate continuous compliance as specified in paragraphs (a)(10)(i) through (a)(10)(vi) of this section. This requirement does not apply to limited-use boilers and process heaters, as defined in § 63.7575.

(i) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown, but you must inspect each burner at least once every 36 months);

(ii) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available;

(iii) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly;

(iv) Optimize total emissions of carbon monoxide. This optimization should be consistent with the manufacturer's specifications, if available;

(v) Measure the concentrations in the effluent stream of carbon monoxide in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made); and

(vi) Maintain on-site and submit, if requested by the Administrator, an annual report containing the information in paragraphs (a)(10)(vi)(A) through (C) of this section,

(A) The concentrations of carbon monoxide in the effluent stream in parts per million by volume, and oxygen in volume percent, measured before and after the adjustments of the boiler;

(B) A description of any corrective actions taken as a part of the combustion adjustment; and

(C) The type and amount of fuel used over the 12 months prior to the annual adjustment, but only if the unit was physically and legally capable of using more than one type of fuel during that period. Units sharing a fuel meter may estimate the fuel use by each unit.

(11) If your boiler or process heater has a heat input capacity of less than 10 million Btu per hour, or meets the definition of limited-use boiler or process heater in § 63.7575, you must conduct a biennial tune-up of the boiler or process heater as specified in paragraphs (a)(10)(i) through (a)(10)(vi) of this section to demonstrate continuous compliance.

(12) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within one week of startup.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 through 4 to this subpart that apply to you. These instances are deviations from the emission limits in this subpart. These deviations must be reported according to the requirements in § 63.7550.

(c) If you elected to demonstrate that the unit meets the specifications for hydrogen sulfide and mercury for the other gas 1 subcategory and you cannot submit a signed certification under § 63.7545(g) because the constituents could exceed the specifications, you must conduct monthly fuel specification testing of the gaseous fuels, according to the procedures in § 63.7521(f) through (i).

§ 63.7541 How do I demonstrate continuous compliance under the emissions averaging provision?

(a) Following the compliance date, the owner or operator must demonstrate compliance with this subpart on a continuous basis by meeting the requirements of paragraphs (a)(1) through (5) of this section.

(1) For each calendar month, demonstrate compliance with the average weighted emissions limit for the existing units participating in the emissions averaging option as determined in § 63.7522(f) and (g).

(2) You must maintain the applicable opacity limit according to paragraphs (a)(2)(i) and (ii) of this section.

(i) For each existing unit participating in the emissions averaging option that is equipped with a dry control system and not vented to a common stack, maintain opacity at or below the applicable limit.

(ii) For each group of units participating in the emissions averaging option where each unit in the group is equipped with a dry control system and vented to a common stack that does not receive emissions from non-affected units, maintain opacity at or below the applicable limit at the common stack.

(3) For each existing unit participating in the emissions averaging option that is equipped with a wet scrubber, maintain the 3-hour average parameter values at or below the operating limits established during the most recent performance test.

(4) For each existing unit participating in the emissions averaging option that has an approved alternative operating plan, maintain the 3-hour average parameter values at or below the operating limits established in the most recent performance test.

(5) For each existing unit participating in the emissions averaging option venting to a common stack configuration containing affected units from other subcategories, maintain the appropriate operating limit for each unit as specified in Table 4 to this subpart that applies.

(b) Any instance where the owner or operator fails to comply with the continuous monitoring requirements in paragraphs (a)(1) through (5) of this section is a deviation.

Notification, Reports, and Records

§ 63.7545 What notifications must I submit and when?

(a) You must submit to the delegated authority all of the notifications in § 63.7(b) and (c), § 63.8(e), (f)(4) and (6), and § 63.9(b) through (h) that apply to you by the dates specified.

(b) As specified in § 63.9(b)(2), if you startup your affected source before May 20, 2011, you must submit an Initial Notification not later than 120 days after May 20, 2011.

(c) As specified in § 63.9(b)(4) and (b)(5), if you startup your new or reconstructed affected source on or after May 20, 2011, you must submit an Initial Notification not later than 15 days after the actual date of startup of the affected source.

(d) If you are required to conduct a performance test you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance test is scheduled to begin.

(e) If you are required to conduct an initial compliance demonstration as specified in § 63.7530(a), you must submit a Notification of Compliance Status according to § 63.9(h)(2)(ii). For the initial compliance demonstration for each affected source, you must submit the Notification of Compliance Status, including all performance test results and fuel analyses, before the close of business on the 60th day following the completion of all performance test and/or other initial compliance demonstrations for the affected source according to § 63.10(d)(2). The Notification of Compliance Status report must contain all the information specified in paragraphs (e)(1) through (8), as applicable.

(1) A description of the affected unit(s) including identification of which subcategory the unit is in, the design heat input capacity of the unit, a description of the add-on controls used on the unit, description of the fuel(s) burned, including whether the fuel(s) were determined by you or EPA through a petition process to be a non-waste under § 241.3, whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of § 241.3, and justification for the selection of fuel(s) burned during the compliance demonstration.

(2) Summary of the results of all performance tests and fuel analyses, and calculations conducted to demonstrate initial compliance including all established operating limits.

(3) A summary of the maximum carbon monoxide emission levels recorded during the performance test to show that you have met any applicable emission standard in Table 1, 2, or 12 to this subpart.

(4) Identification of whether you plan to demonstrate compliance with each applicable emission limit through performance testing or fuel analysis.

(5) Identification of whether you plan to demonstrate compliance by emissions averaging and identification of whether you plan to demonstrate compliance by using emission credits through energy conservation:

(i) If you plan to demonstrate compliance by emission averaging, report the emission level that was being achieved or the control technology employed on May 20, 2011.

(6) A signed certification that you have met all applicable emission limits and work practice standards.

(7) If you had a deviation from any emission limit, work practice standard, or operating limit, you must also submit a description of the deviation, the duration of the deviation, and the corrective action taken in the Notification of Compliance Status report.

(8) In addition to the information required in § 63.9(h)(2), your notification of compliance status must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

(i) "This facility complies with the requirements in § 63.7540(a)(10) to conduct an annual or biennial tune-up, as applicable, of each unit."

(ii) "This facility has had an energy assessment performed according to § 63.7530(e)."

(iii) Except for units that qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act, include the following: "No secondary materials that are solid waste were combusted in any affected unit."

(f) If you operate a unit designed to burn natural gas, refinery gas, or other gas 1 fuels that is subject to this subpart, and you intend to use a fuel other than natural gas, refinery gas, or other gas 1 fuel to fire the affected unit during a period of natural gas curtailment or supply interruption, as defined in § 63.7575, you must submit a notification of alternative fuel use within 48 hours of the declaration of each period of natural gas curtailment or supply interruption, as defined in § 63.7575. The notification must include the information specified in paragraphs (f)(1) through (5) of this section.

(1) Company name and address.

(2) Identification of the affected unit.

(3) Reason you are unable to use natural gas or equivalent fuel, including the date when the natural gas curtailment was declared or the natural gas supply interruption began.

(4) Type of alternative fuel that you intend to use.

(5) Dates when the alternative fuel use is expected to begin and end.

(g) If you intend to commence or recommence combustion of solid waste, you must provide 30 days prior notice of the date upon which you will commence or recommence combustion of solid waste. The notification must identify:

(1) The name of the owner or operator of the affected source, the location of the source, the boiler(s) or process heater(s) that will commence burning solid waste, and the date of the notice.

(2) The currently applicable subcategory under this subpart.

(3) The date on which you became subject to the currently applicable emission limits.

(4) The date upon which you will commence combusting solid waste.

(h) If you intend to switch fuels, and this fuel switch may result in the applicability of a different subcategory, you must provide 30 days prior notice of the date upon which you will switch fuels. The notification must identify:

(1) The name of the owner or operator of the affected source, the location of the source, the boiler(s) that will switch fuels, and the date of the notice.

(2) The currently applicable subcategory under this subpart.

(3) The date on which you became subject to the currently applicable standards.

(4) The date upon which you will commence the fuel switch.

§ 63.7550 What reports must I submit and when?

(a) You must submit each report in Table 9 to this subpart that applies to you.

(b) Unless the EPA Administrator has approved a different schedule for submission of reports under § 63.10(a), you must submit each report by the date in Table 9 to this subpart and according to the requirements in paragraphs (b)(1) through (5) of this section. For units that are subject only to a requirement to conduct an annual or biennial tune-up according to § 63.7540(a)(10) or (a)(11), respectively, and not subject to emission limits or operating limits, you may submit only an annual or biennial compliance report, as applicable, as specified in paragraphs (b)(1) through (5) of this section, instead of a semi-annual compliance report.

(1) The first compliance report must cover the period beginning on the compliance date that is specified for your affected source in § 63.7495 and ending on June 30 or December 31, whichever date is the first date that occurs at least 180 days (or 1 or 2 year, as applicable, if submitting an annual or biennial compliance report) after the compliance date that is specified for your source in § 63.7495.

(2) The first compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the first calendar half after the compliance date that is specified for your source in § 63.7495. The first annual or biennial compliance report must be postmarked no later than January 31.

(3) Each subsequent compliance report must cover the semiannual reporting period from January 1 through June 30 or the semiannual reporting period from July 1 through December 31. Annual and biennial compliance reports must cover the applicable one or two year periods from January 1 to December 31.

(4) Each subsequent compliance report must be postmarked or delivered no later than July 31 or January 31, whichever date is the first date following the end of the semiannual reporting period. Annual and biennial compliance reports must be postmarked no later than January 31.

(5) For each affected source that is subject to permitting regulations pursuant to part 70 or part 71 of this chapter, and if the delegated authority has established dates for submitting semiannual reports pursuant to § 70.6(a)(3)(iii)(A) or § 71.6(a)(3)(iii)(A), you may submit the first and subsequent compliance reports according to the dates the delegated authority has established instead of according to the dates in paragraphs (b)(1) through (4) of this section.

(c) The compliance report must contain the information required in paragraphs (c)(1) through (13) of this section.

(1) Company name and address.

(2) Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.

(3) Date of report and beginning and ending dates of the reporting period.

(4) The total fuel use by each affected source subject to an emission limit, for each calendar month within the

semiannual (or annual or biennial) reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by EPA or your basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

(5) A summary of the results of the annual performance tests for affected sources subject to an emission limit, a summary of any fuel analyses associated with performance tests, and documentation of any operating limits that were reestablished during this test, if applicable. If you are conducting performance tests once every 3 years consistent with § 63.7515(b) or (c), the date of the last 2 performance tests, a comparison of the emission level you achieved in the last 2 performance tests to the 75 percent emission limit threshold required in § 63.7515(b) or (c), and a statement as to whether there have been any operational changes since the last performance test that could increase emissions.

(6) A signed statement indicating that you burned no new types of fuel in an affected source subject to an emission limit. Or, if you did burn a new type of fuel and are subject to a hydrogen chloride emission limit, you must submit the calculation of chlorine input, using Equation 5 of § 63.7530, that demonstrates that your source is still within its maximum chlorine input level established during the previous performance testing (for sources that demonstrate compliance through performance testing) or you must submit the calculation of hydrogen chloride emission rate using Equation 10 of § 63.7530 that demonstrates that your source is still meeting the emission limit for hydrogen chloride emissions (for boilers or process heaters that demonstrate compliance through fuel analysis). If you burned a new type of fuel and are subject to a mercury emission limit, you must submit the calculation of mercury input, using Equation 8 of § 63.7530, that demonstrates that your source is still within its maximum mercury input level established during the previous performance testing (for sources that demonstrate compliance through performance testing), or you must submit the calculation of mercury emission rate using Equation 11 of § 63.7530 that demonstrates that your source is still meeting the emission limit for mercury emissions (for boilers or process heaters that demonstrate compliance through fuel analysis).

(7) If you wish to burn a new type of fuel in an affected source subject to an emission limit and you cannot demonstrate compliance with the maximum chlorine input operating limit using Equation 7 of § 63.7530 or the maximum mercury input operating limit using Equation 8 of § 63.7530, you must include in the compliance report a statement indicating the intent to conduct a new performance test within 60 days of starting to burn the new fuel.

(8) A summary of any monthly fuel analyses conducted to demonstrate compliance according to §§ 63.7521 and 63.7530 for affected sources subject to emission limits, and any fuel specification analyses conducted according to § 63.7521(f) and § 63.7530(g).

(9) If there are no deviations from any emission limits or operating limits in this subpart that apply to you, a statement that there were no deviations from the emission limits or operating limits during the reporting period.

(10) If there were no deviations from the monitoring requirements including no periods during which the CMSs, including CEMS, COMS, and continuous parameter monitoring systems, were out of control as specified in § 63.8(c)(7), a statement that there were no deviations and no periods during which the CMS were out of control during the reporting period.

(11) If a malfunction occurred during the reporting period, the report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must also include a description of actions taken by you during a malfunction of a boiler, process heater, or associated air pollution control device or CMS to minimize emissions in accordance with § 63.7500(a)(3), including actions taken to correct the malfunction.

(12) Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual or biennial tune-up according to § 63.7540(a)(10) or (a)(11), respectively. Include the date of the most recent burner inspection if it was not done annually or biennially and was delayed until the next scheduled unit shutdown.

(13) If you plan to demonstrate compliance by emission averaging, certify the emission level achieved or the control technology employed is no less stringent that the level or control technology contained in the notification of compliance status in § 63.7545(e)(5)(i).

(d) For each deviation from an emission limit or operating limit in this subpart that occurs at an affected source where you are not using a CMS to comply with that emission limit or operating limit, the compliance report must additionally contain the information required in paragraphs (d)(1) through (4) of this section.

(1) The total operating time of each affected source during the reporting period.

(2) A description of the deviation and which emission limit or operating limit from which you deviated.

(3) Information on the number, duration, and cause of deviations (including unknown cause), as applicable, and the corrective action taken.

(4) A copy of the test report if the annual performance test showed a deviation from the emission limits.

(e) For each deviation from an emission limit, operating limit, and monitoring requirement in this subpart occurring at an affected source where you are using a CMS to comply with that emission limit or operating limit, you must include the information required in paragraphs (e)(1) through (12) of this section. This includes any deviations from your site-specific monitoring plan as required in § 63.7505(d).

(1) The date and time that each deviation started and stopped and description of the nature of the deviation (*i.e.*, what you deviated from).

(2) The date and time that each CMS was inoperative, except for zero (low-level) and high-level checks.

(3) The date, time, and duration that each CMS was out of control, including the information in § 63.8(c)(8).

(4) The date and time that each deviation started and stopped.

(5) A summary of the total duration of the deviation during the reporting period and the total duration as a percent of the total source operating time during that reporting period.

(6) An analysis of the total duration of the deviations during the reporting period into those that are due to control equipment problems, process problems, other known causes, and other unknown causes.

(7) A summary of the total duration of CMS's downtime during the reporting period and the total duration of CMS downtime as a percent of the total source operating time during that reporting period.

(8) An identification of each parameter that was monitored at the affected source for which there was a deviation.

(9) A brief description of the source for which there was a deviation.

(10) A brief description of each CMS for which there was a deviation.

(11) The date of the latest CMS certification or audit for the system for which there was a deviation.

(12) A description of any changes in CMSs, processes, or controls since the last reporting period for the source for which there was a deviation.

(f) Each affected source that has obtained a Title V operating permit pursuant to part 70 or part 71 of this chapter must report all deviations as defined in this subpart in the semiannual monitoring report required by § 70.6(a)(3)(iii)(A) or § 71.6(a)(3)(iii)(A). If an affected source submits a compliance report pursuant to Table 9 to this subpart along with, or as part of, the semiannual monitoring report required by § 70.6(a)(3)(iii)(A) or § 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. However, submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the delegated authority.

(g) [Reserved]

(h) As of January 1, 2012 and within 60 days after the date of completing each performance test, as defined in § 63.2, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (*i.e.*, reference method) data and performance test (*i.e.*, compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (see *http://www.epa.gov/ttn/chief/ert/ert tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

§ 63.7555 What records must I keep?

(a) You must keep records according to paragraphs (a)(1) and (2) of this section.

(1) A copy of each notification and report that you submitted to comply with this subpart, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report that you submitted, according to the requirements in § 63.10(b)(2)(xiv).

(2) Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in § 63.10(b)(2)(viii).

(b) For each CEMS, COMS, and continuous monitoring system you must keep records according to paragraphs (b)(1) through (5) of this section.

(1) Records described in § 63.10(b)(2)(vii) through (xi).

(2) Monitoring data for continuous opacity monitoring system during a performance evaluation as required in § 63.6(h)(7)(i) and (ii).

(3) Previous (*i.e.*, superseded) versions of the performance evaluation plan as required in § 63.8(d)(3).

(4) Request for alternatives to relative accuracy test for CEMS as required in § 63.8(f)(6)(i).

(5) Records of the date and time that each deviation started and stopped.

(c) You must keep the records required in Table 8 to this subpart including records of all monitoring data and calculated averages for applicable operating limits, such as opacity, pressure drop, pH, and operating load, to show continuous compliance with each emission limit and operating limit that applies to you.

(d) For each boiler or process heater subject to an emission limit in Table 1, 2 or 12 to this subpart, you must also keep the applicable records in paragraphs (d)(1) through (8) of this section.

(1) You must keep records of monthly fuel use by each boiler or process heater, including the type(s) of fuel and amount(s) used.

(2) If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to § 41.3(b)(1), you must keep a record which documents how the secondary material meets each of the legitimacy criteria. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to § 241.3(b)(4), you must keep records as to how the operations that produced the fuel satisfies the definition of processing in § 241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under § 241.3(c), you must keep a record that documents how the fuel satisfies the requirements of the petition process.

(3) You must keep records of monthly hours of operation by each boiler or process heater that meets the definition of limited-use boiler or process heater.

(4) A copy of all calculations and supporting documentation of maximum chlorine fuel input, using Equation 7 of § 63.7530, that were done to demonstrate continuous compliance with the hydrogen chloride emission limit, for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of hydrogen chloride emission rates, using Equation 10 of § 63.7530, that were done to demonstrate compliance with the hydrogen chloride emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum chlorine fuel input or hydrogen chloride emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate chlorine fuel input, or hydrogen chloride emission rate, for each boiler and process heater.

(5) A copy of all calculations and supporting documentation of maximum mercury fuel input, using Equation 8 of § 63.7530, that were done to demonstrate continuous compliance with the mercury emission limit for sources that demonstrate compliance through performance testing. For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation of mercury emission rates, using Equation 11 of § 63.7530, that were done to demonstrate compliance with the mercury emission limit. Supporting documentation should include results of any fuel analyses and basis for the estimates of maximum mercury fuel input or mercury emission rates. You can use the results from one fuel analysis for multiple boilers and process heaters provided they are all burning the same fuel type. However, you must calculate mercury fuel input, or mercury emission rates, for each boiler and process heater.

(6) If, consistent with § 63.7515(b) and (c), you choose to stack test less frequently than annually, you must keep annual records that document that your emissions in the previous stack test(s) were less than 75 percent of the applicable emission limit, and document that there was no change in source operations including fuel composition and operation of air pollution control equipment that would cause emissions of the relevant pollutant to increase within the past year.

(7) Records of the occurrence and duration of each malfunction of the boiler or process heater, or of the associated air pollution control and monitoring equipment.

(8) Records of actions taken during periods of malfunction to minimize emissions in accordance with the

general duty to minimize emissions in § 63.7500(a)(3), including corrective actions to restore the malfunctioning boiler or process heater, air pollution control, or monitoring equipment to its normal or usual manner of operation.

(e) If you elect to average emissions consistent with § 63.7522, you must additionally keep a copy of the emission averaging implementation plan required in § 63.7522(g), all calculations required under § 63.7522, including monthly records of heat input or steam generation, as applicable, and monitoring records consistent with § 63.7541.

(f) If you elect to use emission credits from energy conservation measures to demonstrate compliance according to § 63.7533, you must keep a copy of the Implementation Plan required in § 63.7533(d) and copies of all data and calculations used to establish credits according to § 63.7533(b), (c), and (f).

(g) If you elected to demonstrate that the unit meets the specifications for hydrogen sulfide and mercury for the other gas 1 subcategory and you cannot submit a signed certification under § 63.7545(g) because the constituents could exceed the specifications, you must maintain monthly records of the calculations and results of the fuel specifications for mercury and hydrogen sulfide in Table 6.

(h) If you operate a unit designed to burn natural gas, refinery gas, or other gas 1 fuel that is subject to this subpart, and you use an alternative fuel other than natural gas, refinery gas, or other gas 1 fuel, you must keep records of the total hours per calendar year that alternative fuel is burned.

§ 63.7560 In what form and how long must I keep my records?

(a) Your records must be in a form suitable and readily available for expeditious review, according to § 63.10(b)(1).

(b) As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record.

(c) You must keep each record on site, or they must be accessible from on site (for example, through a computer network), for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record, according to § 63.10(b)(1). You can keep the records off site for the remaining 3 years.

Other Requirements and Information

§ 63.7565 What parts of the General Provisions apply to me?

Table 10 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you.

§ 63.7570 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by EPA, or a delegated authority such as your State, local, or tribal agency. If the EPA Administrator has delegated authority to your State, local, or tribal agency, then that agency (as well as EPA) has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if this subpart is delegated to your State, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a State, local, or tribal agency under 40 CFR part 63, subpart E, the authorities listed in paragraphs (b)(1) through (5) of this section are retained by the EPA Administrator and are not transferred to the State, local, or tribal agency, however, EPA retains oversight of this subpart and can take enforcement actions, as appropriate.

(1) Approval of alternatives to the non-opacity emission limits and work practice standards in § 63.7500(a) and (b) under § 63.6(g).

(2) Approval of alternative opacity emission limits in § 63.7500(a) under § 63.6(h)(9).

(3) Approval of major change to test methods in Table 5 to this subpart under § 63.7(e)(2)(ii) and (f) and as defined in § 63.90, and alternative analytical methods requested under § 63.7521(b)(2).

(4) Approval of major change to monitoring under § 63.8(f) and as defined in § 63.90, and approval of alternative operating parameters under § 63.7500(a)(2) and § 63.7522(g)(2).

(5) Approval of major change to recordkeeping and reporting under § 63.10(e) and as defined in § 63.90.

§ 63.7575 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act, in § 63.2 (the General Provisions), and in this section as follows:

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

Annual heat input means the heat input for the 12 months preceding the compliance demonstration.

Bag leak detection system means a group of instruments that are capable of monitoring particulate matter loadings in the exhaust of a fabric filter (*i.e.*, baghouse) in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on electrodynamic, triboelectric, light scattering, light transmittance, or other principle to monitor relative particulate matter loadings.

Benchmarking means a process of comparison against standard or average.

Biomass or bio-based solid fuel means any biomass-based solid fuel that is not a solid waste. This includes, but is not limited to, wood residue; wood products (*e.g.*, trees, tree stumps, tree limbs, bark, lumber, sawdust, sander dust, chips, scraps, slabs, millings, and shavings); animal manure, including litter and other bedding materials; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff (*e.g.*, almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds. This definition of biomass is not intended to suggest that these materials are or are not solid waste.

Blast furnace gas fuel-fired boiler or process heater means an industrial/commercial/institutional boiler or process heater that receives 90 percent or more of its total annual gas volume from blast furnace gas.

Boiler means an enclosed device using controlled flame combustion and having the primary purpose of recovering thermal energy in the form of steam or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in § 241.3, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers are excluded from this definition.

Boiler system means the boiler and associated components, such as, the feed water system, the combustion air system, the fuel system (including burners), blowdown system, combustion control system, and energy consuming systems.

Calendar year means the period between January 1 and December 31, inclusive, for a given year.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by ASTM D388 (incorporated by reference, see § 63.14), coal refuse, and petroleum coke. For the purposes of this subpart, this definition of "coal" includes synthetic fuels derived from coal for creating useful heat, including but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures. Coal derived gases are excluded from this definition.

Coal refuse means any by-product of coal mining or coal cleaning operations with an ash content greater than 50 percent (by weight) and a heating value less than 13,900 kilojoules per kilogram (6,000 Btu per pound) on a dry basis.

Commercial/institutional boiler means a boiler used in commercial establishments or institutional establishments such as medical centers, research centers, institutions of higher education, hotels, and laundries to provide steam and/or hot water.

Common stack means the exhaust of emissions from two or more affected units through a single flue. Affected units with a common stack may each have separate air pollution control systems located before the common stack, or may have a single air pollution control system located after the exhausts come together in a single flue.

Cost-effective energy conservation measure means a measure that is implemented to improve the energy efficiency of the boiler or facility that has a payback (return of investment) period of 2 years or less.

Deviation.

(1) *Deviation* means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard; or

(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit.

(2) A deviation is not always a violation. The determination of whether a deviation constitutes a violation of the standard is up to the discretion of the entity responsible for enforcement of the standards.

Dioxins/furans means tetra- through octa-chlorinated dibenzo-p-dioxins and dibenzofurans.

Distillate oil means fuel oils, including recycled oils, that comply with the specifications for fuel oil numbers 1 and 2, as defined by ASTM D396 (incorporated by reference, see § 63.14).

Dry scrubber means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. Sorbent injection systems in fluidized bed boilers and process heaters are included in this definition. A dry scrubber is a dry control system.

Dutch oven means a unit having a refractory-walled cell connected to a conventional boiler setting. Fuel materials are introduced through an opening in the roof of the Dutch oven and burn in a pile on its floor.

Electric utility steam generating unit means a fossil fuel-fired combustion unit of more than 25 megawatts that serves a generator that produces electricity for sale. A fossil fuel-fired unit that cogenerates steam and electricity and supplies more than one-third of its potential electric output capacity and more than 25 megawatts electrical output to any utility power distribution system for sale is considered an electric utility steam generating unit.

Electrostatic precipitator (ESP) means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper. An electrostatic precipitator is usually a dry control system.

Emission credit means emission reductions above those required by this subpart. Emission credits generated may be used to comply with the emissions limits. Credits may come from pollution prevention projects that result in reduced fuel use by affected units. Shutdowns cannot be used to generate credits.

Energy assessment means the following only as this term is used in Table 3 to this subpart.

(1) Energy assessment for facilities with affected boilers and process heaters using less than 0.3 trillion Btu per year heat input will be one day in length maximum. The boiler system and energy use system accounting for at least 50 percent of the energy output will be evaluated to identify energy savings opportunities, within the limit of performing a one-day energy assessment.

(2) The Energy assessment for facilities with affected boilers and process heaters using 0.3 to 1.0 trillion Btu per year will be 3 days in length maximum. The boiler system and any energy use system accounting for at least 33 percent of the energy output will be evaluated to identify energy savings opportunities, within the limit of performing a 3-day energy assessment.

(3) In the Energy assessment for facilities with affected boilers and process heaters using greater than 1.0 trillion Btu per year, the boiler system and any energy use system accounting for at least 20 percent of the energy output will be evaluated to identify energy savings opportunities.

Energy management practices means the set of practices and procedures designed to manage energy use that are demonstrated by the facility's energy policies, a facility energy manager and other staffing responsibilities, energy performance measurement and tracking methods, an energy saving goal, action plans, operating procedures, internal reporting requirements, and periodic review intervals used at the facility.

Energy use system includes, but is not limited to, process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air-conditioning systems; hot heater systems; building envelop; and lighting.

Equivalent means the following only as this term is used in Table 6 to this subpart:

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.

(2) An equivalent sample compositing procedure means a published VCS or EPA method to systematically mix and obtain a representative subsample (part) of the composite sample.

(3) An equivalent sample preparation procedure means a published VCS or EPA method that: Clearly states that the standard, practice or method is appropriate for the pollutant and the fuel matrix; or is cited as an appropriate sample preparation standard, practice or method for the pollutant in the chosen VCS or EPA determinative or analytical method.

(4) An equivalent procedure for determining heat content means a published VCS or EPA method to obtain gross calorific (or higher heating) value.

(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining metals (especially the mercury, selenium, or arsenic) using an aliquot of the dried sample, then the drying

temperature must be modified to prevent vaporizing these metals. On the other hand, if metals analysis is done on an "as received" basis, a separate aliquot can be dried to determine moisture content and the metals concentration mathematically adjusted to a dry basis.

(6) An equivalent pollutant (mercury, hydrogen chloride, hydrogen sulfide) determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for the pollutant and the fuel matrix and has a published detection limit equal or lower than the methods listed in Table 6 to this subpart for the same purpose.

Fabric filter means an add-on air pollution control device used to capture particulate matter by filtering gas streams through filter media, also known as a baghouse. A fabric filter is a dry control system.

Federally enforceable means all limitations and conditions that are enforceable by the EPA Administrator, including the requirements of 40 CFR parts 60 and 61, requirements within any applicable State implementation plan, and any permit requirements established under 40 CFR 52.21 or under 40 CFR 51.18 and 40 CFR 51.24.

Fluidized bed boiler means a boiler utilizing a fluidized bed combustion process.

Fluidized bed combustion means a process where a fuel is burned in a bed of granulated particles, which are maintained in a mobile suspension by the forward flow of air and combustion products.

Fuel cell means a boiler type in which the fuel is dropped onto suspended fixed grates and is fired in a pile. The refractory-lined fuel cell uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, sub-bituminous coal, lignite, anthracite, biomass, residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

Gaseous fuel includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, and biogas. Blast furnace gas is exempted from this definition.

Heat input means heat derived from combustion of fuel in a boiler or process heater and does not include the heat input from preheated combustion air, recirculated flue gases, or exhaust gases from other sources such as gas turbines, internal combustion engines, kilns, etc.

Hourly average means the arithmetic average of at least four CMS data values representing the four 15-minute periods in an hour, or at least two 15-minute data values during an hour when CMS calibration, quality assurance, or maintenance activities are being performed.

Hot water heater means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous or liquid fuel and is withdrawn for use external to the vessel at pressures not exceeding 160 psig, including the apparatus by which the heat is generated and all controls and devices necessary to prevent water temperatures from exceeding 210 degrees Fahrenheit (99 degrees Celsius). *Hot water heater* also means a tankless unit that provides on demand hot water.

Hybrid suspension grate boiler means a boiler designed with air distributors to spread the fuel material over the entire width and depth of the boiler combustion zone. The drying and much of the combustion of the fuel takes place in suspension, and the combustion is completed on the grate or floor of the boiler.

Industrial boiler means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam and/or hot water.

Limited-use boiler or process heater means any boiler or process heater that burns any amount of solid, liquid, or gaseous fuels, has a rated capacity of greater than 10 MMBtu per hour heat input, and has a federally enforceable limit of no more than 876 hours per year of operation.

Liquid fuel subcategory includes any boiler or process heater of any design that burns more than 10 percent liquid fuel and less than 10 percent solid fuel, based on the total annual heat input to the unit.

Liquid fuel includes, but is not limited to, distillate oil, residual oil, on-spec used oil, and biodiesel.

Load fraction means the actual heat input of the boiler or process heater divided by the average operating load determined according to Table 7 to this subpart.

Metal process furnaces include natural gas-fired annealing furnaces, preheat furnaces, reheat furnaces, aging furnaces, heat treat furnaces, and homogenizing furnaces.

Million Btu (MMBtu) means one million British thermal units.

Minimum activated carbon injection rate means load fraction (percent) multiplied by the lowest hourly average activated carbon injection rate measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

Minimum pressure drop means the lowest hourly average pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum scrubber effluent pH means the lowest hourly average sorbent liquid pH measured at the inlet to the wet scrubber according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable hydrogen chloride emission limit.

Minimum scrubber liquid flow rate means the lowest hourly average liquid flow rate (*e.g.*, to the PM scrubber or to the acid gas scrubber) measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum scrubber pressure drop means the lowest hourly average scrubber pressure drop measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limit.

Minimum sorbent injection rate means load fraction (percent) multiplied by the lowest hourly average sorbent injection rate for each sorbent measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

Minimum total secondary electric power means the lowest hourly average total secondary electric power determined from the values of secondary voltage and secondary current to the electrostatic precipitator measured according to Table 7 to this subpart during the most recent performance test demonstrating compliance with the applicable emission limits.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane; or

(2) Liquid petroleum gas, as defined in ASTM D1835 (incorporated by reference, *see* § 63.14); or

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 mega joules (MJ) per dry standard cubic

meter (910 and 1,150 Btu per dry standard cubic foot); or

(4) Propane or propane derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

Operating day means a 24-hour period between 12 midnight and the following midnight during which any fuel is combusted at any time in the boiler or process heater unit. It is not necessary for fuel to be combusted for the entire 24-hour period.

Other gas 1 fuel means a gaseous fuel that is not natural gas or refinery gas and does not exceed the maximum concentration of 40 micrograms/cubic meters of mercury and 4 parts per million, by volume, of hydrogen sulfide.

Particulate matter (PM) means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an approved alternative method.

Period of natural gas curtailment or supply interruption means a period of time during which the supply of natural gas to an affected facility is halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas does not constitute a period of natural gas curtailment or supply interruption.

Process heater means an enclosed device using controlled flame, and the unit's primary purpose is to transfer heat indirectly to a process material (liquid, gas, or solid) or to a heat transfer material for use in a process unit, instead of generating steam. Process heaters are devices in which the combustion gases do not come into direct contact with process materials. A device combusting solid waste, as defined in § 241.3, is not a process heater unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Process heaters do not include units used for comfort heat or space heat, food preparation for on-site consumption, or autoclaves.

Pulverized coal boiler means a boiler in which pulverized coal or other solid fossil fuel is introduced into an air stream that carries the coal to the combustion chamber of the boiler where it is fired in suspension.

Qualified energy assessor means:

(1) someone who has demonstrated capabilities to evaluate a set of the typical energy savings opportunities available in opportunity areas for steam generation and major energy using systems, including, but not limited to:

(i) Boiler combustion management.

(ii) Boiler thermal energy recovery, including

(A) Conventional feed water economizer,

(B) Conventional combustion air preheater, and

(C) Condensing economizer.

(iii) Boiler blowdown thermal energy recovery.

(iv) Primary energy resource selection, including

(A) Fuel (primary energy source) switching, and

(B) Applied steam energy versus direct-fired energy versus electricity.

(v) Insulation issues.

(vi) Steam trap and steam leak management.

(vi) Condensate recovery.

(viii) Steam end-use management.

(2) Capabilities and knowledge includes, but is not limited to:

(i) Background, experience, and recognized abilities to perform the assessment activities, data analysis, and report preparation.

(ii) Familiarity with operating and maintenance practices for steam or process heating systems.

(iii) Additional potential steam system improvement opportunities including improving steam turbine operations and reducing steam demand.

(iv) Additional process heating system opportunities including effective utilization of waste heat and use of proper process heating methods.

(v) Boiler-steam turbine cogeneration systems.

(vi) Industry specific steam end-use systems.

Refinery gas means any gas that is generated at a petroleum refinery and is combusted. Refinery gas includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Refinery gas includes gases generated from other facilities when that gas is combined and combusted in any proportion with gas generated at a refinery.

Residual oil means crude oil, and all fuel oil numbers 4, 5 and 6, as defined in ASTM D396–10 (incorporated by reference, see § 63.14(b)).

Responsible official means responsible official as defined in § 70.2.

Solid fossil fuel includes, and is not limited to, coal, coke, petroleum coke, and tire derived fuel.

Solid fuel means any solid fossil fuel or biomass or bio-based solid fuel.

Steam output means (1) for a boiler that produces steam for process or heating only (no power generation), the energy content in terms of MMBtu of the boiler steam output, and (2) for a boiler that cogenerates process steam and electricity (also known as combined heat and power (CHP)), the total energy output, which is the sum of the energy content of the steam exiting the turbine and sent to process in MMBtu and the energy of the electricity generated converted to MMBtu at a rate of 10,000 Btu per kilowatt-hour generated (10 MMBtu per megawatt-hour).

Stoker means a unit consisting of a mechanically operated fuel feeding mechanism, a stationary or moving grate to support the burning of fuel and admit under-grate air to the fuel, an overfire air system to complete combustion, and an ash discharge system. This definition of stoker includes air swept stokers. There are two general types of stokers: Underfeed and overfeed. Overfeed stokers include mass feed and spreader stokers.

Suspension boiler means a unit designed to feed the fuel by means of fuel distributors. The distributors inject air at the point where the fuel is introduced into the boiler in order to spread the fuel material over the boiler width. The drying (and much of the combustion) occurs while the material is suspended in air. The combustion of the fuel material is completed on a grate or floor below. Suspension boilers almost universally are designed to have high heat release rates to dry quickly the wet fuel as it is blown into the boilers.

Temporary boiler means any gaseous or liquid fuel boiler that is designed to, and is capable of, being carried or moved from one location to another by means of, for example, wheels, skids, carrying handles, dollies, trailers, or platforms. A boiler is not a temporary boiler if any one of the following conditions exists:

(1) The equipment is attached to a foundation.

(2) The boiler or a replacement remains at a location for more than 12 consecutive months. Any temporary boiler that replaces a temporary boiler at a location and performs the same or similar function will be included in calculating the consecutive time period.

(3) The equipment is located at a seasonal facility and operates during the full annual operating period of the seasonal facility, remains at the facility

for at least 2 years, and operates at that facility for at least 3 months each year.

(4) The equipment is moved from one location to another in an attempt to circumvent the residence time requirements of this definition.

Tune-up means adjustments made to a boiler in accordance with procedures supplied by the manufacturer (or an approved specialist) to optimize the combustion efficiency.

Unit designed to burn biomass/bio-based solid subcategory includes any boiler or process heater that burns at least 10 percent biomass or bio-based solids on an annual heat input basis in combination with solid fossil fuels, liquid fuels, or gaseous fuels.

Unit designed to burn coal/solid fossil fuel subcategory includes any boiler or process heater that burns any coal or other solid fossil fuel alone or at least 10 percent coal or other solid fossil fuel on an annual heat input basis in combination with liquid fuels, gaseous fuels, or less than 10 percent biomass and bio-based solids on an annual heat input basis.

Unit designed to burn gas 1 subcategory includes any boiler or process heater that burns only natural gas, refinery gas, and/or other gas 1 fuels; with the exception of liquid fuels burned for periodic testing not to exceed a combined total of 48 hours during any calendar year, or during periods of gas curtailment and gas supply emergencies.

Unit designed to burn gas 2 (other) subcategory includes any boiler or process heater that is not in the unit designed to burn gas 1 subcategory and burns any gaseous fuels either alone or in combination with less than 10 percent coal/solid fossil fuel, less than 10 percent biomass/bio-based solid fuel, and less than 10 percent liquid fuels on an annual heat input basis.

Unit designed to burn liquid subcategory includes any boiler or process heater that burns any liquid fuel, but less than 10 percent coal/solid fossil fuel and less than 10 percent biomass/bio-based solid fuel on an annual heat input basis, either alone or in combination with gaseous fuels. Gaseous fuel boilers and process heaters that burn liquid fuel for periodic testing of liquid fuel, maintenance, or operator training, not to exceed a combined total of 48 hours during any calendar year or during periods of maintenance, operator training, or testing of liquid fuel, not to exceed a combined total of 48 hours during any calendar year are not included in this definition. Gaseous fuel boilers and process heaters that burn liquid fuel during periods of gas curtailment or gas supply emergencies of any duration are also not included in this definition.

Unit designed to burn liquid fuel that is a non-continental unit means an industrial, commercial, or institutional boiler or process heater designed to burn liquid fuel located in the State of Hawaii, the Virgin Islands, Guam, American Samoa, the Commonwealth of Puerto Rico, or the Northern Mariana Islands.

Unit designed to burn solid fuel subcategory means any boiler or process heater that burns any solid fuel alone or at least 10 percent solid fuel on an annual heat input basis in combination with liquid fuels or gaseous fuels.

Voluntary Consensus Standards or VCS mean technical standards (*e.g.*, materials specifications, test methods, sampling procedures, business practices) developed or adopted by one or more voluntary consensus bodies. EPA/Office of Air Quality Planning and Standards, by precedent, has only used VCS that are written in English. Examples of VCS bodies are: American Society of Testing and Materials (ASTM 100 Barr Harbor Drive, P.O. Box CB700, West Conshohocken, Pennsylvania 19428–B2959, (800) 262–1373, *http://www.astm.org*), American Society of Mechanical Engineers (ASME ASME, Three Park Avenue, New York, NY 10016–5990, (800) 843–2763, *http://www.asme.org*), International Standards Organization (ISO 1, ch. de la Voie-Creuse, Case postale 56, CH–1211 Geneva 20, Switzerland, +41 22 749 01 11, *http://www.iso.org/iso/home.htm*), Standards Australia (AS Level 10, The Exchange Centre, 20 Bridge Street, Sydney, GPO Box 476, Sydney NSW 2001, + 61 2 9237 6171 *http://www.stadards.org.au*), British Standards Institution (BSI, 389 Chiswick High Road, London, W4 4AL, United Kingdom, +44 (0)20 8996 9001, *http://www.bsigroup.com*), Canadian Standards Association (CSA 5060 Spectrum Way, Suite 100, Mississauga, Ontario L4W 5N6, Canada, 800–463–6727, *http://www.csa.ca*), European Committee for Standardization (CEN CENELEC Management Centre Avenue Marnix 17 B–1000 Brussels, Belgium +32 2 550 08 11, *http://www.cen.eu/cen*), and German Engineering Standards (VDI VDI Guidelines Department, P.O. Box 10 11 39 40002, Duesseldorf, Germany, +49 211 6214–230, *http://www.vdi.eu*). The types of standards that are not considered VCS are standards developed by: The United States, *e.g.*, California (CARB) and Texas (TCEQ); industry groups, such as American Petroleum Institute (API), Gas Processors Association (GPA), and Gas Research Institute (GRI); and other branches of the U.S. government, *e.g.*, Department of Defense (DOD) and Department of Transportation (DOT). This does not preclude EPA from using standards developed by groups that are not VCS bodies within their rule. When this occurs, EPA has done searches and reviews for VCS equivalent to these non-EPA methods.

Waste heat boiler means a device that recovers normally unused energy and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators.

Waste heat process heater means an enclosed device that recovers normally unused energy and converts it to usable heat. Waste heat process heaters are also referred to as recuperative process heaters.

Wet scrubber means any add-on air pollution control device that mixes an aqueous stream or slurry with the exhaust gases from a boiler or process heater to control emissions of particulate matter or to absorb and neutralize acid gases, such as hydrogen chloride. A wet scrubber creates an aqueous stream or slurry as a byproduct of the emissions control process.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, that is promulgated pursuant to section 112(h) of the Clean Air Act.

Tables to Subpart DDDDD of Part 63

As stated in § 63.7500, you must comply with the following applicable emission limits:

TABLE 1 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS [a]

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Or the emissions must not exceed the following output-based limits (lb per MMBtu of steam output) . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. Particulate Matter	0.0011 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	0.0011; (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 3 dscm per run.
	b. Hydrogen Chloride	0.0022 lb per MMBtu of heat input.	0.0021	For M26A, collect a minimum of 1 dscm per run; for M26 collect a minimum of 60 liters per run.
	c. Mercury	3.5E–06 lb per MMBtu of heat input.	3.4E–06	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 2 dscm.
2. Units designed to burn pulverized coal/solid fossil fuel.	a. Carbon monoxide (CO)	12 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.01	1 hr minimum sampling time, use a span value of 30 ppmv.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen.	2.8E–12 (TEQ)	Collect a minimum of 4 dscm per run.
3. Stokers designed to burn coal/solid fossil fuel.	a. CO	6 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.005	1 hr minimum sampling time, use a span value of 20 ppmv.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen.	2.8E–12 (TEQ)	Collect a minimum of 4 dscm per run.
4. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO	18 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.02	1 hr minimum sampling time, use a span value of 40 ppmv.
	b. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen.	1.8E–12 (TEQ)	Collect a minimum of 4 dscm per run.
5. Stokers designed to burn biomass/bio-based solids.	a. CO	160 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.13	1 hr minimum sampling time, use a span value of 400 ppmv.
	b. Dioxins/Furans	0.005 ng/dscm (TEQ) corrected to 7 percent oxygen.	4.4E–12 (TEQ)	Collect a minimum of 4 dscm per run.
6. Fluidized bed units designed to burn biomass/bio-based solids.	a. CO	260 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.18	1 hr minimum sampling time, use a span value of 500 ppmv.
	b. Dioxins/Furans	0.02 ng/dscm (TEQ) corrected to 7 percent oxygen.	1.8E–11 (TEQ)	Collect a minimum of 4 dscm per run.
7. Suspension burners/Dutch Ovens designed to burn biomass/bio-based solids.	a. CO	470 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.45	1 hr minimum sampling time, use a span value of 1000 ppmv.
	b. Dioxins/Furans	0.2 ng/dscm (TEQ) corrected to 7 percent oxygen.	1.8E–10 (TEQ)	Collect a minimum of 4 dscm per run.
8. Fuel cells designed to burn biomass/bio-based solids.	a. CO	470 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.23	1 hr minimum sampling time, use a span value of 1000 ppmv.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen.	2.86E–12 (TEQ)	Collect a minimum of 4 dscm per run.
9. Hybrid suspension/grate units designed to burn biomass/bio-based solids.	a. CO	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.84	1 hr minimum sampling time, use a span value of 3000 ppmv.

TABLE 1 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS [a]—Continued

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Or the emissions must not exceed the following output-based limits (lb per MMBtu of steam output) . . .	Using this specified sampling volume or test run duration . . .
	b. Dioxins/Furans	0.2 ng/dscm (TEQ) corrected to 7 percent oxygen.	1.8E–10 (TEQ)	Collect a minimum of 4 dscm per run.
10. Units designed to burn liquid fuel.	a. Particulate Matter	0.0013 lb per MMBtu of heat input (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units).	0.001; (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units).	Collect a minimum of 3 dscm per run.
	b. Hydrogen Chloride	0.00033 lb per MMBtu of heat input.	0.0003	For M26A: Collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	2.1E–07 lb per MMBtu of heat input.	0.2E–06	Collect enough volume to meet an in-stack detection limit data quality objective of 0.10 ug/dscm.
	d. CO	3 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.0026	1 hr minimum sampling time, use a span value of 3 ppmv.
	e. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen.	4.6E–12 (TEQ)	Collect a minimum of 4 dscm per run.
11. Units designed to burn liquid fuel located in non-continental States and territories.	a. Particulate Matter	0.0013 lb per MMBtu of heat input (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units).	0.001; (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units).	Collect a minimum of 3 dscm per run.
	b. Hydrogen Chloride	0.00033 lb per MMBtu of heat input.	0.0003	For M26A: Collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	7.8E–07 lb per MMBtu of heat input.	8.0E–07	For M29, collect a minimum of 3 dscm per run; for M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 3 dscm.
	d. CO	51 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.043	1 hr minimum sampling time, use a span value of 100 ppmv.
	e. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen.	4.6E–12(TEQ)	Collect a minimum of 3 dscm per run.
12. Units designed to burn gas 2 (other) gases.	a. Particulate Matter	0.0067 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	.004; (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 1 dscm per run.
	b. Hydrogen Chloride	0.0017 lb per MMBtu of heat input.	.003	For M26A, Collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.

TABLE 1 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS [a]—Continued

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	Or the emissions must not exceed the following output-based limits (lb per MMBtu of steam output) . . .	Using this specified sampling volume or test run duration . . .
	c. Mercury	7.9E–06 lb per MMBtu of heat input.	2.0E–07	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [b] collect a minimum of 2 dscm.
	d. CO	3 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.002	1 hr minimum sampling time, use a span value of 10 ppmv.
	e. Dioxins/Furans	0.08 ng/dscm (TEQ) corrected to 7 percent oxygen.	4.1E–12 (TEQ)	Collect a minimum of 4 dscm per run

[a] If your affected source is a new or reconstructed affected source that commenced construction or reconstruction after June 4, 2010, and before May 20, 2011, you may comply with the emission limits in Table 12 to this subpart until March 21, 2014. On and after March 21, 2014, you must comply with the emission limits in Table 1 to this subpart.

[b] Incorporated by reference, see § 63.14.

As stated in § 63.7500, you must comply with the following applicable emission limits:

TABLE 2 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	The emissions must not exceed the following output-based limits (lb per MMBtu of steam output) . . .	Using this specified sampling volume or test run duration . . .
1. Units in all subcategories designed to burn solid fuel.	a. Particulate Matter	0.039 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	0.038; (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 1 dscm per run.
	b. Hydrogen Chloride	0.035 lb per MMBtu of heat input.	0.04	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	4.6E–06 lb per MMBtu of heat input.	4.5E–06	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [a] collect a minimum of 2 dscm.
2. Pulverized coal units designed to burn pulverized coal/solid fossil fuel.	a. CO	160 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.14	1 hr minimum sampling time, use a span value of 300 ppmv.
	b. Dioxins/Furans	0.004 ng/dscm (TEQ) corrected to 7 percent oxygen.	3.7E–12 (TEQ)	Collect a minimum of 4 dscm per run.
3. Stokers designed to burn coal/solid fossil fuel.	a. CO	270 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.25	1 hr minimum sampling time, use a span value of 500 ppmv.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen.	2.8E–12 (TEQ)	Collect a minimum of 4 dscm per run.

TABLE 2 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS—Continued

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	The emissions must not exceed the following output-based limits (lb per MMBtu of steam output) . . .	Using this specified sampling volume or test run duration . . .
4. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO	82 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.08	1 hr minimum sampling time, use a span value of 200 ppmv
	b. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen.	1.8E–12 (TEQ)	Collect a minimum of 4 dscm per run.
5. Stokers designed to burn biomass/bio-based solid.	a. CO	490 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.35	1 hr minimum sampling time, use a span value of 1000 ppmv.
	b. Dioxins/Furans	0.005 ng/dscm (TEQ) corrected to 7 percent oxygen.	4.4E–12 (TEQ)	Collect a minimum of 4 dscm per run.
6. Fluidized bed units designed to burn biomass/bio-based solid.	a. CO	430 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.28	1 hr minimum sampling time, use a span value of 850 ppmv.
	b. Dioxins/Furans	0.02 ng/dscm (TEQ) corrected to 7 percent oxygen.	1.8E–11(TEQ)	Collect a minimum of 4 dscm per run.
7. Suspension burners/Dutch Ovens designed to burn biomass/bio-based solid.	a. CO	470 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.45	1 hr minimum sampling time, use a span value of 1000 ppmv.
	b. Dioxins/Furans	0.2 ng/dscm (TEQ) corrected to 7 percent oxygen.	1.8E–10 (TEQ)	Collect a minimum of 4 dscm per run.
8. Fuel cells designed to burn biomass/bio-based solid.	a. CO	690 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.34	1 hr minimum sampling time, use a span value of 1300 ppmv.
	b. Dioxins/Furans	4 ng/dscm (TEQ) corrected to 7 percent oxygen.	3.5E–09 (TEQ)	Collect a minimum of 4 dscm per run.
9. Hybrid suspension/grate units designed to burn biomass/bio-based solid.	a. CO	3,500 ppm by volume on a dry basis corrected to 3 percent oxygen.	2.0	1 hr minimum sampling time, use a span value of 7000 ppmv.
	b. Dioxins/Furans	0.2 ng/dscm (TEQ) corrected to 7 percent oxygen.	1.8E–10 (TEQ)	Collect a minimum of 4 dscm per run.
10. Units designed to burn liquid fuel.	a. Particulate Matter	0.0075 lb per MMBtu of heat input (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units).	0.0073; (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units).	Collect a minimum of 1 dscm per run.
	b. Hydrogen Chloride	0.00033 lb per MMBtu of heat input.	0.0003	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 200 liters per run.
	c. Mercury	3.5E–06 lb per MMBtu of heat input.	3.3E–06	For M29, collect a minimum of 1 dscm per run; for M30A or M30B collect a minimum sample as specified in the method, for ASTM D6784[a] collect a minimum of 2 dscm.
	d. CO	10 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.0083	1 hr minimum sampling time, use a span value of 20 ppmv.
	e. Dioxins/Furans	4 ng/dscm (TEQ) corrected to 7 percent oxygen.	9.2E–09 (TEQ)	Collect a minimum of 1 dscm per run.

TABLE 2 TO SUBPART DDDDD OF PART 63—EMISSION LIMITS FOR EXISTING BOILERS AND PROCESS HEATERS—Continued

[Units with heat input capacity of 10 million Btu per hour or greater]

If your boiler or process heater is in this subcategory . . .	For the following pollutants . . .	The emissions must not exceed the following emission limits, except during periods of startup and shutdown . . .	The emissions must not exceed the following output-based limits (lb per MMBtu of steam output) . . .	Using this specified sampling volume or test run duration . . .
11. Units designed to burn liquid fuel located in non-continental States and territories.	a. Particulate Matter	0.0075 lb per MMBtu of heat input (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units).	0.0073; (30-day rolling average for residual oil-fired units 250 MMBtu/hr or greater, 3-run average for other units).	Collect a minimum of 1 dscm per run.
	b. Hydrogen Chloride	0.00033 lb per MMBtu of heat input.	0.0003	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 200 liters per run.
	c. Mercury	7.8E–07 lb per MMBtu of heat input.	8.0E–07	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[a] collect a minimum of 2 dscm.
	d. CO	160 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.13	1 hr minimum sampling time, use a span value of 300 ppmv.
	e. Dioxins/Furans	4 ng/dscm (TEQ) corrected to 7 percent oxygen.	9.2E–09 (TEQ)	Collect a minimum of 1 dscm per run.
12. Units designed to burn gas 2 (other) gases.	a. Particulate Matter	0.043 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	0.026; (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 1 dscm per run.
	b. Hydrogen Chloride	0.0017 lb per MMBtu of heat input.	0.001	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	1.3E–05 lb per MMBtu of heat input.	7.8E–06	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[a] collect a minimum of 2 dscm.
	d. CO	9 ppm by volume on a dry basis corrected to 3 percent oxygen.	0.005	1 hr minimum sampling time, use a span value of 20 ppmv.
	e. Dioxins/Furans	0.08 ng/dscm (TEQ) corrected to 7 percent oxygen.	3.9E–11 (TEQ)	Collect a minimum of 4 dscm per run.

[a] Incorporated by reference, see § 63.14.

As stated in § 63.7500, you must comply with the following applicable work practice standards:

TABLE 3 TO SUBPART DDDDD OF PART 63—WORK PRACTICE STANDARDS

If your unit is . . .	You must meet the following . . .
1. A new or existing boiler or process heater with heat input capacity of less than 10 million Btu per hour or a limited use boiler or process heater.	Conduct a tune-up of the boiler or process heater biennially as specified in § 63.7540.

TABLE 3 TO SUBPART DDDDD OF PART 63—WORK PRACTICE STANDARDS—Continued

If your unit is . . .	You must meet the following . . .
2. A new or existing boiler or process heater in either the Gas 1 or Metal Process Furnace subcategory with heat input capacity of 10 million Btu per hour or greater.	Conduct a tune-up of the boiler or process heater annually as specified in § 63.7540.
3. An existing boiler or process heater located at a major source facility	Must have a one-time energy assessment performed on the major source facility by qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table, satisfies the energy assessment requirement. The energy assessment must include: a. A visual inspection of the boiler or process heater system. b. An evaluation of operating characteristics of the facility, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints, c. An inventory of major energy consuming systems, d. A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage, e. A review of the facility's energy management practices and provide recommendations for improvements consistent with the definition of energy management practices, f. A list of major energy conservation measures, g. A list of the energy savings potential of the energy conservation measures identified, and h. A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.
4. An existing or new unit subject to emission limits in Tables 1, 2, or 12 of this subpart..	Minimize the unit's startup and shutdown periods following the manufacturer's recommended procedures. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available.

As stated in § 63.7500, you must comply with the applicable operating limits:

TABLE 4 TO SUBPART DDDDD OF PART 63—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS

If you demonstrate compliance using . . .	You must meet these operating limits . . .
1. Wet PM scrubber control	Maintain the 12-hour block average pressure drop and the 12-hour block average liquid flow rate at or above the lowest 1-hour average pressure drop and the lowest 1-hour average liquid flow rate, respectively, measured during the most recent performance test demonstrating compliance with the PM emission limitation according to § 63.7530(b) and Table 7 to this subpart.
2. Wet acid gas (HCl) scrubber control	Maintain the 12-hour block average effluent pH at or above the lowest 1-hour average pH and the 12-hour block average liquid flow rate at or above the lowest 1-hour average liquid flow rate measured during the most recent performance test demonstrating compliance with the HCl emission limitation according to § 63.7530(b) and Table 7 to this subpart.
3. Fabric filter control on units not required to install and operate a PM CEMS.	a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); or b. Install and operate a bag leak detection system according to § 63.7525 and operate the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during each 6-month period.
4. Electrostatic precipitator control on units not required to install and operate a PM CEMS.	a. This option is for boilers and process heaters that operate dry control systems (*i.e.,* an ESP without a wet scrubber). Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (daily block average); or b. This option is only for boilers and process heaters not subject to PM CEMS or continuous compliance with an opacity limit (i.e., COMS). Maintain the minimum total secondary electric power input of the electrostatic precipitator at or above the operating limits established during the performance test according to § 63.7530(b) and Table 7 to this subpart.
5. Dry scrubber or carbon injection control	Maintain the minimum sorbent or carbon injection rate as defined in § 63.7575 of this subpart.

TABLE 4 TO SUBPART DDDDD OF PART 63—OPERATING LIMITS FOR BOILERS AND PROCESS HEATERS—Continued

If you demonstrate compliance using . . .	You must meet these operating limits . . .
6. Any other add-on air pollution control type on units not required to install and operate a PM CEMS.	This option is for boilers and process heaters that operate dry control systems. Existing and new boilers and process heaters must maintain opacity to less than or equal to 10 percent opacity (daily block average).
7. Fuel analysis	Maintain the fuel type or fuel mixture such that the applicable emission rates calculated according to § 63.7530(c)(1), (2) and/or (3) is less than the applicable emission limits.
8. Performance testing	For boilers and process heaters that demonstrate compliance with a performance test, maintain the operating load of each unit such that is does not exceed 110 percent of the average operating load recorded during the most recent performance test.
9. Continuous Oxygen Monitoring System	For boilers and process heaters subject to a carbon monoxide emission limit that demonstrate compliance with an O_2 CEMS as specified in § 63.7525(a), maintain the oxygen level of the stack gas such that it is not below the lowest hourly average oxygen concentration measured during the most recent CO performance test.

As stated in § 63.7520, you must comply with the following requirements for performance testing for existing, new or reconstructed affected sources:

TABLE 5 TO SUBPART DDDDD OF PART 63—PERFORMANCE TESTING REQUIREMENTS

To conduct a performance test for the following pollutant...	You must...	Using...
1. Particulate Matter	a. Select sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas..	Method 2, 2F, or 2G at 40 CFR part 60, appendix A–1 or A–2 to part 60 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–2 to part 60 of this chapter, or ANSI/ASME PTC 19.10–1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	e. Measure the particulate matter emission concentration.	Method 5 or 17 (positive pressure fabric filters must use Method 5D) at 40 CFR part 60, appendix A–3 or A–6 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology at 40 CFR part 60, appendix A–7 of this chapter.
2. Hydrogen chloride	a. Select sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G at 40 CFR part 60, appendix A–2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–2 of this chapter, or ANSI/ASME PTC 19.10–1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	e. Measure the hydrogen chloride emission concentration.	Method 26 or 26A (M26 or M26A) at 40 CFR part 60, appendix A–8 of this chapter.
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology at 40 CFR part 60, appendix A–7 of this chapter.
3. Mercury	a. Select sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G at 40 CFR part 60, appendix A–1 or A–2 of this chapter.
	c. Determine oxygen or carbon dioxide concentration of the stack gas.	Method 3A or 3B at 40 CFR part 60, appendix A–1 of this chapter, or ANSI/ASME PTC 19.10–1981.[a]
	d. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	e. Measure the mercury emission concentration	Method 29, 30A, or 30B (M29, M30A, or M30B) at 40 CFR part 60, appendix A–8 of this chapter or Method 101A at 40 CFR part 60, appendix B of this chapter, or ASTM Method D6784.[a]
	f. Convert emissions concentration to lb per MMBtu emission rates.	Method 19 F-factor methodology at 40 CFR part 60, appendix A–7 of this chapter.
4. CO	a. Select the sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.

TABLE 5 TO SUBPART DDDDD OF PART 63—PERFORMANCE TESTING REQUIREMENTS—Continued

To conduct a performance test for the following pollutant...	You must...	Using...
	b. Determine oxygen concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A–3 of this chapter, or ASTM D6522–00 (Reapproved 2005), or ANSI/ASME PTC 19.10–1981.[a]
	c. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	d. Measure the CO emission concentration	Method 10 at 40 CFR part 60, appendix A–4 of this chapter. Use a span value of 2 times the concentration of the applicable emission limit.
5. Dioxins/Furans	a. Select the sampling ports location and the number of traverse points.	Method 1 at 40 CFR part 60, appendix A–1 of this chapter.
	b. Determine oxygen concentration of the stack gas	Method 3A or 3B at 40 CFR part 60, appendix A–3 of this chapter, or ASTM D6522–00 (Reapproved 2005),[a] or ANSI/ASME PTC 19.10–1981.[a]
	c. Measure the moisture content of the stack gas	Method 4 at 40 CFR part 60, appendix A–3 of this chapter.
	d. Measure the dioxins/furans emission concentration	Method 23 at 40 CFR part 60, appendix A–7 of this chapter.
	e. Multiply the measured dioxins/furans emission concentration by the appropriate toxic equivalency factor.	Table 11 of this subpart.

[a] Incorporated by reference, see § 63.14.

As stated in § 63.7521, you must comply with the following requirements for fuel analysis testing for existing, new or reconstructed affected sources. However, equivalent methods (as defined in § 63.7575) may be used in lieu of the prescribed methods at the discretion of the source owner or operator:

TABLE 6 TO SUBPART DDDDD OF PART 63—FUEL ANALYSIS REQUIREMENTS

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
1. Mercury	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D2234/D2234M[a] (for coal) or ASTM D6323[a] (for biomass), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW–846–3050B[a] (for solid samples), EPA SW–846–3020A[a] (for liquid samples), ASTM D2013/D2013M[a] (for coal), ASTM D5198[a] (for biomass), or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865[a] (for coal) or ASTM E711[a] (for biomass), or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173[a] or ASTM E871,[a] or equivalent.
	f. Measure mercury concentration in fuel sample.	ASTM D6722[a] (for coal), EPA SW–846–7471B[a] (for solid samples), or EPA SW–846–7470A[a] (for liquid samples), or equivalent.
	g. Convert concentration into units of pounds of pollutant per MMBtu of heat content.	
2. Hydrogen Chloride	a. Collect fuel samples	Procedure in § 63.7521(c) or ASTM D2234/D2234M[a] (for coal) or ASTM D6323[a] (for biomass), or equivalent.
	b. Composite fuel samples	Procedure in § 63.7521(d) or equivalent.
	c. Prepare composited fuel samples	EPA SW–846–3050B[a] (for solid samples), EPA SW–846–3020A[a] (for liquid samples), ASTM D2013/D2013M[a] (for coal), or ASTM D5198[a] (for biomass), or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865[a] (for coal) or ASTM E711[a] (for biomass), or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173[a] or ASTM E871,[a] or equivalent.
	f. Measure chlorine concentration in fuel sample.	EPA SW–846–9250,[a] ASTM D6721[a] (for coal), or ASTM E776[a] (for biomass), or equivalent.
	g. Convert concentrations into units of pounds of pollutant per MMBtu of heat content.	
3. Mercury Fuel Specification for other gas 1 fuels.	a. Measure mercury concentration in the fuel sample.	ASTM D5954,[a]
	b. Convert concentration to unit of micrograms/cubic meter.	ASTM D6350,[a] ISO 6978–1:2003(E),[a] or ISO 6978–2:2003(E)[a], or equivalent.

TABLE 6 TO SUBPART DDDDD OF PART 63—FUEL ANALYSIS REQUIREMENTS—Continued

To conduct a fuel analysis for the following pollutant . . .	You must . . .	Using . . .
4. Hydrogen Sulfide Fuel Specification for other gas 1 fuels.	a. Measure total hydrogen sulfide .... b. Convert to ppm	ASTM D4084a or equivalent.

[a] Incorporated by reference, see § 63.14.

As stated in § 63.7520, you must comply with the following requirements for establishing operating limits:

TABLE 7 TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
1. Particulate matter or mercury.	a. Wet scrubber operating parameters.	i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to § 63.7530(b).	(1) Data from the pressure drop and liquid flow rate monitors and the particulate matter or mercury performance test.	(a) You must collect pressure drop and liquid flow rate data every 15 minutes during the entire period of the performance tests; (b) Determine the lowest hourly average pressure drop and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.
	b. Electrostatic precipitator operating parameters (option only for units that operate wet scrubbers).	i. Establish a site-specific minimum total secondary electric power input according to § 63.7530(b).	(1) Data from the voltage and secondary amperage monitors during the particulate matter or mercury performance test.	(a) You must collect secondary voltage and secondary amperage for each ESP cell and calculate total secondary electric power input data every 15 minutes during the entire period of the performance tests; (b) Determine the average total secondary electric power input by computing the hourly averages using all of the 15-minute readings taken during each performance test.
2. Hydrogen Chloride	a. Wet scrubber operating parameters.	i. Establish site-specific minimum pressure drop, effluent pH, and flow rate operating limits according to § 63.7530(b).	(1) Data from the pressure drop, pH, and liquid flow-rate monitors and the hydrogen chloride performance test.	(a) You must collect pH and liquid flow-rate data every 15 minutes during the entire period of the performance tests; (b) Determine the hourly average pH and liquid flow rate by computing the hourly averages using all of the 15-minute readings taken during each performance test.

TABLE 7 TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS—Continued

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
	b. Dry scrubber operating parameters.	i. Establish a site-specific minimum sorbent injection rate operating limit according to § 63.7530(b). If different acid gas sorbents are used during the hydrogen chloride performance test, the average value for each sorbent becomes the site-specific operating limit for that sorbent.	(1) Data from the sorbent injection rate monitors and hydrogen chloride or mercury performance test.	(a) You must collect sorbent injection rate data every 15 minutes during the entire period of the performance tests; (b) Determine the hourly average sorbent injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average of the three test run averages established during the performance test as your operating limit. When your unit operates at lower loads, multiply your sorbent injection rate by the load fraction (e.g., for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
3. Mercury and dioxins/furans.	a. Activated carbon injection.	i. Establish a site-specific minimum activated carbon injection rate operating limit according to § 63.7530(b).	(1) Data from the activated carbon rate monitors and mercury and dioxins/furans performance tests.	(a) You must collect activated carbon injection rate data every 15 minutes during the entire period of the performance tests; (b) Determine the hourly average activated carbon injection rate by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average established during the performance test as your operating limit. When your unit operates at lower loads, multiply your activated carbon injection rate by the load fraction (e.g., actual heat input divided by heat input during performance test, for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
4. Carbon monoxide	a. Oxygen	i. Establish a unit-specific limit for minimum oxygen level according to § 63.7520.	(1) Data from the oxygen monitor specified in § 63.7525(a).	(a) You must collect oxygen data every 15 minutes during the entire period of the performance tests;

TABLE 7 TO SUBPART DDDDD OF PART 63—ESTABLISHING OPERATING LIMITS—Continued

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must . . .	Using . . .	According to the following requirements
				(b) Determine the hourly average oxygen concentration by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the lowest hourly average established during the performance test as your minimum operating limit.
5. Any pollutant for which compliance is demonstrated by a performance test.	a. Boiler or process heater operating load.	i. Establish a unit specific limit for maximum operating load according to § 63.7520(c).	(1) Data from the operating load monitors or from steam generation monitors.	(a) You must collect operating load or steam generation data every 15 minutes during the entire period of the performance test. (b) Determine the average operating load by computing the hourly averages using all of the 15-minute readings taken during each performance test. (c) Determine the average of the three test run averages during the performance test, and multiply this by 1.1 (110 percent) as your operating limit.

As stated in § 63.7540, you must show continuous compliance with the emission limitations for affected sources according to the following:

TABLE 8 TO SUBPART DDDDD OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
1. Opacity	a. Collecting the opacity monitoring system data according to § 63.7525(c) and § 63.7535; and b. Reducing the opacity monitoring data to 6-minute averages; and c. Maintaining opacity to less than or equal to 10 percent (daily block average).
2. Fabric Filter Bag Leak Detection Operation	Installing and operating a bag leak detection system according to § 63.7525 and operating the fabric filter such that the requirements in § 63.7540(a)(9) are met.
3. Wet Scrubber Pressure Drop and Liquid Flow-rate.	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§ 63.7525 and 63.7535; and b. Reducing the data to 12-hour block averages; and c. Maintaining the 12-hour average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to § 63.7530(b).
4. Wet Scrubber pH	a. Collecting the pH monitoring system data according to §§ 63.7525 and 63.7535; and b. Reducing the data to 12-hour block averages; and c. Maintaining the 12-hour average pH at or above the operating limit established during the performance test according to § 63.7530(b).
5. Dry Scrubber Sorbent or Carbon Injection Rate.	a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber according to §§ 63.7525 and 63.7535; and b. Reducing the data to 12-hour block averages; and c. Maintaining the 12-hour average sorbent or carbon injection rate at or above the minimum sorbent or carbon injection rate as defined in § 63.7575.
6. Electrostatic Precipitator Total Secondary Electric Power Input.	a. Collecting the total secondary electric power input monitoring system data for the electrostatic precipitator according to §§ 63.7525 and 63.7535; and b. Reducing the data to 12-hour block averages; and c. Maintaining the 12-hour average total secondary electric power input at or above the operating limits established during the performance test according to § 63.7530(b).
7. Fuel Pollutant Content	a. Only burning the fuel types and fuel mixtures used to demonstrate compliance with the applicable emission limit according to § 63.7530(b) or (c) as applicable; and b. Keeping monthly records of fuel use according to § 63.7540(a).

TABLE 8 TO SUBPART DDDDD OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE—Continued

If you must meet the following operating limits or work practice standards . . .	You must demonstrate continuous compliance by . . .
8. Oxygen content	a. Continuously monitor the oxygen content in the combustion exhaust according to § 63.7525(a). b. Reducing the data to 12-hour block averages; and c. Maintain the 12-hour block average oxygen content in the exhaust at or above the lowest hourly average oxygen level measured during the most recent carbon monoxide performance test.
9. Boiler or process heater operating load	a. Collecting operating load data or steam generation data every 15 minutes. b. Reducing the data to 12-hour block averages; and c. Maintaining the 12-hour average operating load at or below the operating limit established during the performance test according to § 63.7520(c).

As stated in § 63.7550, you must comply with the following requirements for reports:

TABLE 9 TO SUBPART DDDDD OF PART 63—REPORTING REQUIREMENTS

You must submit a(n)	The report must contain . . .	You must submit the report . . .
1. Compliance report	a. Information required in § 63.7550(c)(1) through (12); and b. If there are no deviations from any emission limitation (emission limit and operating limit) that applies to you and there are no deviations from the requirements for work practice standards in Table 3 to this subpart that apply to you, a statement that there were no deviations from the emission limitations and work practice standards during the reporting period. If there were no periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), a statement that there were no periods during which the CMSs were out-of-control during the reporting period; and c. If you have a deviation from any emission limitation (emission limit and operating limit) where you are not using a CMS to comply with that emission limit or operating limit, or a deviation from a work practice standard during the reporting period, the report must contain the information in § 63.7550(d); and d. If there were periods during which the CMSs, including continuous emissions monitoring system, continuous opacity monitoring system, and operating parameter monitoring systems, were out-of-control as specified in § 63.8(c)(7), or otherwise not operating, the report must contain the information in § 63.7550(e).	Semiannually, annually, or biennially according to the requirements in § 63.7550(b).

As stated in § 63.7565, you must comply with the applicable General Provisions according to the following:

TABLE 10 TO SUBPART DDDDD OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART DDDDD

Citation	Subject	Applies to subpart DDDDD
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.7575
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements	Yes.
§ 63.6(a), (b)(1)–(b)(5), (b)(7), (c)	Compliance with Standards and Maintenance Requirements	Yes.
§ 63.6(e)(1)(i)	General duty to minimize emissions.	No. See § 63.7500(a)(3) for the general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions as soon as practicable.	No.
§ 63.6(e)(3)	Startup, shutdown, and malfunction plan requirements.	No.
§ 63.6(f)(1)	Startup, shutdown, and malfunction exemptions for compliance with non-opacity emission standards..	No.
§ 63.6(f)(2) and (3)	Compliance with non-opacity emission standards.	Yes.
§ 63.6(g)	Use of alternative standards	Yes.
§ 63.6(h)(1)	Startup, shutdown, and malfunction exemptions to opacity standards.	No. See § 63.7500(a).
§ 63.6(h)(2) to (h)(9)	Determining compliance with opacity emission standards	Yes.

TABLE 10 TO SUBPART DDDDD OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART DDDDD—Continued

Citation	Subject	Applies to subpart DDDDD
§ 63.6(i)	Extension of compliance.	Yes.
§ 63.6(j)	Presidential exemption.	Yes.
§ 63.7(a), (b), (c), and (d)	Performance Testing Requirements	Yes.
§ 63.7(e)(1)	Conditions for conducting performance tests.	No. Subpart DDDDD specifies conditions for conducting performance tests at § 63.7520(a).
§ 63.7(e)(2)–(e)(9), (f), (g), and (h)	Performance Testing Requirements	Yes.
§ 63.8(a) and (b)	Applicability and Conduct of Monitoring	Yes.
§ 63.8(c)(1)	Operation and maintenance of CMS	Yes.
§ 63.8(c)(1)(i)	General duty to minimize emissions and CMS operation	No. See § 63.7500(a)(3).
§ 63.8(c)(1)(ii)	Operation and maintenance of CMS	Yes.
§ 63.8(c)(1)(iii)	Startup, shutdown, and malfunction plans for CMS	No.
§ 63.8(c)(2) to (c)(9)	Operation and maintenance of CMS	Yes.
§ 63.8(d)(1) and (2)	Monitoring Requirements, Quality Control Program	Yes.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for the last sentence, which refers to a startup, shutdown, and malfunction plan. Startup, shutdown, and malfunction plans are not required.
§ 63.8(e)	Performance evaluation of a CMS	Yes.
§ 63.8(f)	Use of an alternative monitoring method.	Yes.
63.8(g)	Reduction of monitoring data.	Yes.
§ 63.9	Notification Requirements	Yes.
§ 63.10(a), (b)(1)	Recordkeeping and Reporting Requirements	Yes.
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups or shutdowns	Yes.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for actions taken during malfunctions.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv) and (v)	Actions taken to minimize emissions during startup, shutdown, or malfunction.	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§ 63.10(b)(2)(vii) to (xiv)	Other CMS requirements	Yes.
§ 63.10(b)(3)	Recordkeeping requirements for applicability determinations	No.
§ 63.10(c)(1) to (9)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(10) and (11)	Recording nature and cause of malfunctions, and corrective actions	No. See § 63.7555(d)(7) for recordkeeping of occurrence and duration and § 63.7555(d)(8) for actions taken during malfunctions.
§ 63.10(c)(12) and (13)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(15)	Use of startup, shutdown, and malfunction plan	No.
§ 63.10(d)(1) and (2)	General reporting requirements	Yes.
§ 63.10(d)(3)	Reporting opacity or visible emission observation results	No.
§ 63.10(d)(4)	Progress reports under an extension of compliance	Yes.
§ 63.10(d)(5)	Startup, shutdown, and malfunction reports	No. See § 63.7550(c)(11) for malfunction reporting requirements.
§ 63.10(e) and (f)		Yes.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and Delegation	Yes.
§ 63.13–63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions.	Yes.
§ 63.1(a)(5),(a)(7)–(a)(9), (b)(2), (c)(3)-(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)–(4), (c)(9)..	Reserved	No.

TABLE 11 TO SUBPART DDDDD OF PART 63—TOXIC EQUIVALENCY FACTORS FOR DIOXINS/FURANS

Dioxin/furan congener	Toxic equivalency factor
2,3,7,8-tetrachlorinated dibenzo-p-dioxin	1
1,2,3,7,8-pentachlorinated dibenzo-p-dioxin	1
1,2,3,4,7,8-hexachlorinated dibenzo-p-dioxin	0.1
1,2,3,7,8,9-hexachlorinated dibenzo-p-dioxin	0.1
1,2,3,6,7,8-hexachlorinated dibenzo-p-dioxin	0.1

TABLE 11 TO SUBPART DDDDD OF PART 63—TOXIC EQUIVALENCY FACTORS FOR DIOXINS/FURANS—Continued

Dioxin/furan congener	Toxic equivalency factor
1,2,3,4,6,7,8-heptachlorinated dibenzo-p-dioxin	0.01
octachlorinated dibenzo-p-dioxin	0.0003
2,3,7,8-tetrachlorinated dibenzofuran	0.1
2,3,4,7,8-pentachlorinated dibenzofuran	0.3
1,2,3,7,8-pentachlorinated dibenzofuran	0.03
1,2,3,4,7,8-hexachlorinated dibenzofuran	0.1
1,2,3,6,7,8-hexachlorinated dibenzofuran	0.1
1,2,3,7,8,9-hexachlorinated dibenzofuran	0.1
2,3,4,6,7,8-hexachlorinated dibenzofuran	0.1
1,2,3,4,6,7,8-heptachlorinated dibenzofuran	0.01
1,2,3,4,7,8,9-heptachlorinated dibenzofuran	0.01
octachlorinated dibenzofuran	0.0003

TABLE 12 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER JUNE 4, 2010, AND BEFORE MAY 20, 2011

If your boiler or process heater is in this subcategory	For the following pollutants	The emissions must not exceed the following emission limits, except during periods of startup and shutdown	Using this specified sampling volume or test run duration
1. Units in all subcategories designed to burn solid fuel	a. Mercury	3.5E–06 lb per MMBtu of heat input.	For M29, collect a minimum of 2 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784[a] collect a minimum of 2 dscm.
2. Units in all subcategories designed to burn solid fuel that combust at least 10 percent biomass/bio-based solids on an annual heat input basis and less than 10 percent coal/solid fossil fuels on an annual heat input basis.	a. Particulate Matter	0.008 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 1 dscm per run.
	b. Hydrogen Chloride	0.004 lb per MMBtu of heat input.	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
3. Units in all subcategories designed to burn solid fuel that combust at least 10 percent coal/solid fossil fuels on an annual heat input basis and less than 10 percent biomass/bio-based solids on an annual heat input basis.	a. Particulate Matter	0.0011 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 3 dscm per run.
	b. Hydrogen Chloride	0.0022 lb per MMBtu of heat input.	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
4. Units designed to burn pulverized coal/solid fossil fuel.	a. CO	90 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
5. Stokers designed to burn coal/solid fossil fuel	a. CO	7 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
6. Fluidized bed units designed to burn coal/solid fossil fuel.	a. CO	30 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.

TABLE 12 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER JUNE 4, 2010, AND BEFORE MAY 20, 2011—Continued

If your boiler or process heater is in this subcategory	For the following pollutants	The emissions must not exceed the following emission limits, except during periods of startup and shutdown	Using this specified sampling volume or test run duration
	b. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
7. Stokers designed to burn biomass/bio-based solids	a. CO	560 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Dioxins/Furans	0.005 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
8. Fluidized bed units designed to burn biomass/bio-based solids.	a. CO	260 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Dioxins/Furans	0.02 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
9. Suspension burners/Dutch Ovens designed to burn biomass/bio-based solids.	a. CO	1,010 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Dioxins/Furans	0.2 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
10. Fuel cells designed to burn biomass/bio-based solids.	a. CO	470 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Dioxins/Furans	0.003 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
11. Hybrid suspension/grate units designed to burn biomass/bio-based solids.	a. CO	1,500 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	b. Dioxins/Furans	0.2 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
12. Units designed to burn liquid fuel	a. Particulate Matter	0.002 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 2 dscm per run.
	b. Hydrogen Chloride	0.0032 lb per MMBtu of heat input.	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	3.0E–07 lb per MMBtu of heat input.	For M29, collect a minimum of 2 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [a] collect a minimum of 2 dscm.
	d. CO	3 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	e. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
13. Units designed to burn liquid fuel located in non-continental States and territories.	a. Particulate Matter	0.002 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 2 dscm per run.

TABLE 12 TO SUBPART DDDDD OF PART 63—ALTERNATIVE EMISSION LIMITS FOR NEW OR RECONSTRUCTED BOILERS AND PROCESS HEATERS THAT COMMENCED CONSTRUCTION OR RECONSTRUCTION AFTER JUNE 4, 2010, AND BEFORE MAY 20, 2011—Continued

If your boiler or process heater is in this subcategory	For the following pollutants	The emissions must not exceed the following emission limits, except during periods of startup and shutdown	Using this specified sampling volume or test run duration
	b. Hydrogen Chloride	0.0032 lb per MMBtu of heat input.	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	7.8E–07 lb per MMBtu of heat input.	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [a] collect a minimum of 2 dscm.
	d. CO	51 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	e. Dioxins/Furans	0.002 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.
14. Units designed to burn gas 2 (other) gases	a. Particulate Matter	0.0067 lb per MMBtu of heat input (30-day rolling average for units 250 MMBtu/hr or greater, 3-run average for units less than 250 MMBtu/hr).	Collect a minimum of 1 dscm per run.
	b. Hydrogen Chloride	0.0017 lb per MMBtu of heat input.	For M26A, collect a minimum of 1 dscm per run; for M26, collect a minimum of 60 liters per run.
	c. Mercury	7.9E–06 lb per MMBtu of heat input.	For M29, collect a minimum of 1 dscm per run; for M30A or M30B, collect a minimum sample as specified in the method; for ASTM D6784 [a] collect a minimum of 2 dscm.
	d. CO	3 ppm by volume on a dry basis corrected to 3 percent oxygen.	1 hr minimum sampling time.
	e. Dioxins/Furans	0.08 ng/dscm (TEQ) corrected to 7 percent oxygen.	Collect a minimum of 4 dscm per run.

[a] Incorporated by reference, see § 63.14.

[FR Doc. 2011–4494 Filed 3–18–11; 8:45 am]
BILLING CODE 6560–50–P

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

Executive Order 12898 (59 FR 7629, February 16, 1994) establishes federal executive policy on environmental justice (EJ). Its main provision directs federal agencies, to the greatest extent practicable and permitted by law, to make EJ part of their mission by identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of their programs, policies, and activities on minority populations, low-income, and tribal populations in the United States.

This action establishes national emission standards for industrial, commercial, and institutional boilers that are area sources. The industrial boiler source category includes boilers used in manufacturing, processing, mining, refining, or any other industry. The commercial boiler source category includes boilers used in commercial establishments such as stores/malls, laundries, apartments, restaurants, theatres, and hotels/motels. The institutional boiler source category includes boilers used in medical centers (*e.g.*, hospitals, clinics, nursing homes), educational and religious facilities (*e.g.*, schools, universities, places of worship), and municipal buildings (*e.g.*, courthouses, arts centers, prisons). There are approximately 92,000 facilities affected by this final rule, most of which are small entities. By the defined nature of the category, many of these sources are located in close proximity to residential areas, commercial centers, and other locations where large numbers of people live and work.

Due to the large number of these sources, their nation-wide dispersal, and the absence of site specific coordinates, EPA is unable to examine the distributions of exposures and health risks attributable to these sources among different socio-demographic groups for this rule, or to relate the locations of expected emission reductions to the locations of current poor air quality. However, this final rule is anticipated to have substantial emissions reductions of toxic air pollutants (*see* Table 2 of this preamble), some of which are potential carcinogens, neurotoxins, and respiratory irritants. This final rule will also result in reductions in criteria pollutants such as CO, PM, SO_2, as well as ozone precursors.

Because of the close proximity of these source categories to people, the substantial emission reductions of air toxics resulting from the implementation of this rule is anticipated to have health benefits for all persons living or going near these types of sources. (Please refer to the RIA for this rulemaking, which is available in the docket.) For example, there will be reductions of mercury emissions which will reduce potential exposures due to the atmospheric deposition of mercury for populations such as subsistence fisherman. In addition, there will be reductions in other air toxics which can cause adverse health effects such as ozone precursors that contribute to "smog." EPA has determined that this rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it increases the level of environmental protection for all affected populations without having any disproportionately high and adverse human health or environmental effects on any population, including any minority, low-income, or tribal populations.

EPA defines "Environmental Justice" to include meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and polices. To promote meaningful involvement, EPA has developed an EJ communication strategy to ensure that interested communities have access to this rule, are aware of its content, and have an opportunity to comment. In addition, state and federal permitting requirements will provide state and local governments and communities the opportunity to provide their comments on the permit conditions associated with permitting these sources.

K. Congressional Review Act

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating this final rule must submit a rule report, which includes a copy of this final rule, to each House of the Congress and to the Comptroller General of the United States. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of this final rule in the **Federal Register**. A major rule cannot take effect until 60 days after it is published in the **Federal Register**. This action is a "major rule" as defined by 5 U.S.C. 804(2). This rule will be effective May 20, 2011.

List of Subjects in 40 CFR Part 63

Environmental protection, Administrative practice and procedure, Air pollution control, Hazardous substances, Intergovernmental relations, Incorporation by reference, Reporting and recordkeeping requirements.

Dated: February 21, 2011.

Lisa P. Jackson,

Administrator.

For the reasons stated in the preamble, title 40, chapter I, part 63 of the Code of Federal Regulations is amended as follows:

PART 63—[AMENDED]

■ 1. The authority citation for part 63 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart A—[Amended]

■ 2. Section 63.14 is amended by:
■ a. Revising paragraphs (b)(27), (b)(35), (b)(39) through (44), (b)(47) through (52), (b)(57), (b)(61), (b)(64), and (i)(1).
■ b. Removing and reserving paragraphs (b)(45), (b)(46), (b)(55), (b)(56), (b)(58) through (60), and (b)(62).
■ c. Adding paragraphs (b)(66) through (68).
■ d. Adding paragraphs (p) and (q).

§ 63.14 Incorporation by reference.

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(b) * * *

(27) ASTM D6522–00, Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, IBR approved for § 63.9307(c)(2).

* * * * *

(35) ASTM D6784–02 (Reapproved 2008) Standard Test Method for Elemental, Oxidized, Particle-Bound and Total Mercury in Flue Gas Generated from Coal-Fired Stationary Sources (Ontario Hydro Method), approved April 1, 2008, IBR approved for table 1 to subpart DDDDD of this part, table 2 to subpart DDDDD of this part, table 5 to subpart DDDDD, table 12 to subpart DDDDD of this part, and table 4 to subpart JJJJJJ of this part.

* * * * *

(39) ASTM Method D388–05, Standard Classification of Coals by Rank, approved September 15, 2005, IBR approved for § 63.7575 and § 63.11237.

(40) ASTM D396–10 Standard Specification for Fuel Oils, approved October 1, 2010, IBR approved for § 63.7575.

(41) ASTM Method D1835–05, Standard Specification for Liquefied Petroleum (LP) Gases, approved April 1, 2005, IBR approved for § 63.7575 and § 63.11237.

(42) ASTM D2013/D2013M–09 Standard Practice for Preparing Coal Samples for Analysis, approved November 1, 2009, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJJ of this part.

(43) ASTM D2234/D2234M–10 Standard Practice for Collection of a Gross Sample of Coal, approved January 1, 2010, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJJ of this part.

(44) ASTM D3173–03 (Reapproved 2008) Standard Test Method for Moisture in the Analysis Sample of Coal and Coke, approved February 1, 2008, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJJ of this part.

* * * * *

(47) ASTM D5198–09 Standard Practice for Nitric Acid Digestion of Solid Waste, approved February 1, 2009, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJJ of this part.

(48) ASTM D5865–10a Standard Test Method for Gross Calorific Value of Coal and Coke, approved May 1, 2010, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJJ of this part.

(49) ASTM D6323–98 (Reapproved 2003), Standard Guide for Laboratory Subsampling of Media Related to Waste Management Activities, approved August 10, 2003, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJJ of this part.

(50) ASTM E711–87 (Reapproved 2004) Standard Test Method for Gross Calorific Value of Refuse-Derived Fuel by the Bomb Calorimeter, approved August 28, 1987, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJJ of this part.

(51) ASTM E776–87 (Reapproved 2009) Standard Test Method for Forms of Chlorine in Refuse-Derived Fuel, approved July 1, 2009, IBR approved for table 6 to subpart DDDDD of this part.

(52) ASTM E871–82 (Reapproved 2006) Standard Test Method for Moisture Analysis of Particulate Wood Fuels, approved November 1, 2006, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJJ of this part.

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(57) ASTM D6721–01 (Reapproved 2006) Standard Test Method for Determination of Chlorine in Coal by Oxidative Hydrolysis Microcoulometry, approved April 1, 2006, IBR approved for table 6 to subpart DDDDD of this part.

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(61) ASTM D6722–01 (Reapproved 2006) Standard Test Method for Total Mercury in Coal and Coal Combustion Residues by the Direct Combustion Analysis, approved April 1, 2006, IBR approved for Table 6 to subpart DDDDD and Table 5 to subpart JJJJJJ of this part.

* * * * *

(64) ASTM D6522–00 (Reapproved 2005), Standard Test Method for Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Concentrations in Emissions from Natural Gas Fired Reciprocating Engines, Combustion Turbines, Boilers, and Process Heaters Using Portable Analyzers, approved October 1, 2005, IBR approved for table 4 to subpart ZZZZ of this part, table 5 to subpart DDDDD of this part, and table 4 to subpart JJJJJJ of this part.

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(66) ASTM D4084–07 Standard Test Method for Analysis of Hydrogen Sulfide in Gaseous Fuels (Lead Acetate Reaction Rate Method), approved June 1, 2007, IBR approved for table 6 to subpart DDDDD of this part.

(67) ASTM D5954–98 (Reapproved 2006), Test Method for Mercury Sampling and Measurement in Natural Gas by Atomic Absorption Spectroscopy, approved December 1, 2006, IBR approved for table 6 to subpart DDDDD of this part.

(68) ASTM D6350–98 (Reapproved 2003) Standard Test Method for Mercury Sampling and Analysis in Natural Gas by Atomic Fluorescence Spectroscopy, approved May 10, 2003, IBR approved for table 6 to subpart DDDDD of this part.

(i) * * *

(1) ANSI/ASME PTC 19.10–1981, "Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus]," IBR approved for §§ 63.309(k)(1)(iii), 63.865(b), 63.3166(a)(3), 63.3360(e)(1)(iii), 63.3545(a)(3), 63.3555(a)(3), 63.4166(a)(3), 63.4362(a)(3), 63.4766(a)(3), 63.4965(a)(3), 63.5160(d)(1)(iii), 63.9307(c)(2), 63.9323(a)(3), 63.11148(e)(3)(iii), 63.11155(e)(3), 63.11162(f)(3)(iii) and (f)(4), 63.11163(g)(1)(iii) and (g)(2), 63.11410(j)(1)(iii), 63.11551(a)(2)(i)(C), table 5 to subpart DDDDD of this part, table 1 to subpart ZZZZZ of this part, and table 4 to subpart JJJJJJ of this part.

* * * * *

(p) The following material is available from the U.S. Environmental Protection Agency, 1200 Pennsylvania Avenue, NW., Washington, DC 20460, (202) 272–0167, *http://www.epa.gov.*

(1) National Emission Standards for Hazardous Air Pollutants (NESHAP) for Integrated Iron and Steel Plants—Background Information for Proposed Standards, Final Report, EPA–453/R–01–005, January 2001, IBR approved for § 63.7491(g).

(2) Office Of Air Quality Planning And Standards (OAQPS), Fabric Filter Bag Leak Detection Guidance, EPA–454/R–98–015, September 1997, IBR approved for § 63.7525(j)(2) and § 63.11224(f)(2).

(3) SW–846–3020A, Acid Digestion of Aqueous Samples And Extracts For Total Metals For Analysis By GFAA Spectroscopy, Revision 1, July 1992, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJJ of this part.

(4) SW–846–3050B, Acid Digestion of Sediments, Sludges, And Soils, Revision 2, December 1996, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJJ of this part.

(5) SW–846–7470A, Mercury In Liquid Waste (Manual Cold-Vapor Technique), Revision 1, September 1994, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJJ of this part.

(6) SW–846–7471B, Mercury In Solid Or Semisolid Waste (Manual Cold-Vapor Technique), Revision 2, February 2007, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD of this part and table 5 to subpart JJJJJJ of this part.

(7) SW–846–9250, Chloride (Colorimetric, Automated Ferricyanide AAI), Revision 0, September 1986, in EPA Publication No. SW–846, Test Methods for Evaluating Solid Waste, Physical/Chemical Methods, Third Edition, IBR approved for table 6 to subpart DDDDD of this part.

(q) The following material is available for purchase from the International

Standards Organization (ISO), 1, ch. de la Voie-Creuse, Case postale 56, CH–1211 Geneva 20, Switzerland, +41 22 749 01 11, *http://www.iso.org/iso/home.htm.*

(1) ISO 6978–1:2003(E), Natural Gas—Determination of Mercury—Part 1: Sampling of Mercury by Chemisorption on Iodine, First edition, October 15, 2003, IBR approved for table 6 to subpart DDDDD of this part.

(2) ISO 6978–2:2003(E), Natural gas—Determination of Mercury—Part 2: Sampling of Mercury by Amalgamation on Gold/Platinum Alloy, First edition, October 15, 2003, IBR approved for table 6 to subpart DDDDD of this part.

■ 3. Part 63 is amended by adding subpart JJJJJJ to read as follows:

Subpart JJJJJJ—National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

Sec.

Subpart JJJJJJ—National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Sources

What This Subpart Covers

§ 63.11193 Am I subject to this subpart?

You are subject to this subpart if you own or operate an industrial, commercial, or institutional boiler as defined in § 63.11237 that is located at, or is part of, an area source of hazardous air pollutants (HAP), as defined in § 63.2, except as specified in § 63.11195.

§ 63.11194 What is the affected source of this subpart?

(a) This subpart applies to each new, reconstructed, or existing affected source as defined in paragraphs (a)(1) and (2) of this section.

(1) The affected source is the collection of all existing industrial, commercial, and institutional boilers within a subcategory (coal, biomass, oil), as listed in § 63.11200 and defined in § 63.11237, located at an area source.

(2) The affected source of this subpart is each new or reconstructed industrial, commercial, or institutional boiler within a subcategory, as listed in § 63.11200 and as defined in § 63.11237, located at an area source.

(b) An affected source is an existing source if you commenced construction or reconstruction of the affected source on or before June 4, 2010.

(c) An affected source is a new source if you commenced construction or reconstruction of the affected source after June 4, 2010 and you meet the applicability criteria at the time you commence construction.

(d) A boiler is a new affected source if you commenced fuel switching from natural gas to solid fossil fuel, biomass, or liquid fuel after June 4, 2010.

(e) If you are an owner or operator of an area source subject to this subpart, you are exempt from the obligation to obtain a permit under 40 CFR part 70 or part 71 as a result of this subpart. You may, however, be required to obtain a title V permit due to another reason or reasons. *See* 40 CFR 70.3(a) and (b) or 71.3(a) and (b). Notwithstanding the exemption from title V permitting for area sources under this subpart, you must continue to comply with the provisions of this subpart.

§ 63.11195 Are any boilers not subject to this subpart?

The types of boilers listed in paragraphs (a) through (g) of this section are not subject to this subpart and to any requirements in this subpart.

(a) Any boiler specifically listed as, or included in the definition of, an affected source in another standard(s) under this part.

(b) Any boiler specifically listed as an affected source in another standard(s) established under section 129 of the Clean Air Act.

(c) A boiler required to have a permit under section 3005 of the Solid Waste Disposal Act or covered by subpart EEE of this part (e.g., hazardous waste boilers).

(d) A boiler that is used specifically for research and development. This exemption does not include boilers that solely or primarily provide steam (or heat) to a process or for heating at a research and development facility. This exemption does not prohibit the use of the steam (or heat) generated from the boiler during research and development, however, the boiler must be concurrently and primarily engaged in research and development for the exemption to apply.

(e) A gas-fired boiler as defined in this subpart.

(f) A hot water heater as defined in this subpart.

(g) Any boiler that is used as a control device to comply with another subpart of this part, provided that at least 50 percent of the heat input to the boiler is provided by the gas stream that is regulated under another subpart.

§ 63.11196 What are my compliance dates?

(a) If you own or operate an existing affected boiler, you must achieve compliance with the applicable provisions in this subpart as specified in paragraphs (a)(1) through (3) of this section.

(1) If the existing affected boiler is subject to a work practice or management practice standard of a tune-up, you must achieve compliance with the work practice or management standard no later than March 21, 2012.

(2) If the existing affected boiler is subject to emission limits, you must achieve compliance with the emission limits no later than March 21, 2014.

(3) If the existing affected boiler is subject to the energy assessment requirement, you must achieve compliance with the energy assessment requirement no later than March 21, 2014.

(b) If you start up a new affected source on or before May 20, 2011, you must achieve compliance with the provisions of this subpart no later than May 20, 2011.

(c) If you start up a new affected source after May 20, 2011, you must achieve compliance with the provisions of this subpart upon startup of your affected source.

(d) If you own or operate an industrial, commercial, or institutional boiler and would be subject to this subpart except for the exemption in § 63.11195(b) for commercial and industrial solid waste incineration units covered by 40 CFR part 60, subpart CCCC or subpart DDDD, and you cease combusting solid waste, you must be in compliance with this subpart on the effective date of the waste to fuel switch.

Emission Limits, Work Practice Standards, Emission Reduction Measures, and Management Practices

§ 63.11200 What are the subcategories of boilers?

The subcategories of boilers are coal, biomass, and oil. Each subcategory is defined in § 63.11237.

§ 63.11201 What standards must I meet?

(a) You must comply with each emission limit specified in Table 1 to this subpart that applies to your boiler.

(b) You must comply with each work practice standard, emission reduction measure, and management practice specified in Table 2 to this subpart that applies to your boiler. An energy assessment completed on or after January 1, 2008 that meets the requirements in Table 2 to this subpart satisfies the energy assessment portion of this requirement.

(c) You must comply with each operating limit specified in Table 3 to this subpart that applies to your boiler.

(d) These standards apply at all times.

General Compliance Requirements

§ 63.11205 What are my general requirements for complying with this subpart?

(a) At all times you must operate and maintain any affected source, including associated air pollution control equipment and monitoring equipment, in a manner consistent with safety and good air pollution control practices for minimizing emissions. The general duty to minimize emissions does not require you to make any further efforts to reduce emissions if levels required by this standard have been achieved. Determination of whether such operation and maintenance procedures are being used will be based on information available to the Administrator that may include, but is not limited to, monitoring results, review of operation and maintenance procedures, review of operation and maintenance records, and inspection of the source.

(b) You can demonstrate compliance with any applicable mercury emission limit using fuel analysis if the emission rate calculated according to § 63.11211(c) is less than the applicable emission limit. Otherwise, you must demonstrate compliance using stack testing.

(c) If you demonstrate compliance with any applicable emission limit through performance stack testing and subsequent compliance with operating limits (including the use of continuous parameter monitoring system), with a CEMS, or with a COMS, you must develop a site-specific monitoring plan according to the requirements in paragraphs (c)(1) through (3) of this section for the use of any CEMS, COMS, or continuous parameter monitoring system. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under § 63.8(f).

(1) For each continuous monitoring system required in this section (including CEMS, COMS, or continuous parameter monitoring system), you must develop, and submit to the delegated authority for approval upon request, a site-specific monitoring plan that addresses paragraphs (c)(1)(i) through (vi) of this section. You must submit this site-specific monitoring plan, if requested, at least 60 days before your initial performance evaluation of your CMS. This requirement to develop and submit a site specific monitoring plan does not apply to affected sources with existing monitoring plans that apply to CEMS and COMS prepared under Appendix B to part 60 of this chapter and which meet the requirements of § 63.11224.

(i) Installation of the continuous monitoring system sampling probe or other interface at a measurement location relative to each affected process unit such that the measurement is representative of control of the exhaust emissions (*e.g.*, on or downstream of the last control device);

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems; and

(iii) Performance evaluation procedures and acceptance criteria (*e.g.*, calibrations).

(iv) Ongoing operation and maintenance procedures in accordance with the general requirements of § 63.8(c)(1)(ii), (c)(3), and (c)(4)(ii);

(v) Ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d); and

(vi) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of § 63.10(c) (as applicable in Table 8 to this subpart), (e)(1), and (e)(2)(i).

(2) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.

(3) You must operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.

Initial Compliance Requirements

§ 63.11210 What are my initial compliance requirements and by what date must I conduct them?

(a) You must demonstrate initial compliance with each emission limit specified in Table 1 to this subpart that applies to you by either conducting performance (stack) tests, as applicable, according to § 63.11212 and Table 4 to this subpart or, for mercury, conducting fuel analyses, as applicable, according to § 63.11213 and Table 5 to this subpart.

(b) For existing affected boilers that have applicable emission limits, you must demonstrate initial compliance no later than 180 days after the compliance date that is specified in § 63.11196 and according to the applicable provisions in § 63.7(a)(2).

(c) For existing affected boilers that have applicable work practice standards, management practices, or emission reduction measures, you must demonstrate initial compliance no later than the compliance date that is specified in § 63.11196 and according to the applicable provisions in § 63.7(a)(2).

(d) For new or reconstructed affected sources, you must demonstrate initial compliance no later than 180 calendar days after March 21, 2011 or within 180 calendar days after startup of the source, whichever is later, according to § 63.7(a)(2)(ix).

(e) For affected boilers that ceased burning solid waste consistent with § 63.11196(d), you must demonstrate compliance within 60 days of the effective date of the waste-to-fuel switch. If you have not conducted your compliance demonstration for this subpart within the previous 12 months, you must complete all compliance demonstrations before you commence or recommence combustion of solid waste.

§ 63.11211 How do I demonstrate initial compliance with the emission limits?

(a) For affected boilers that demonstrate compliance with any of the emission limits of this subpart through performance (stack) testing, your initial compliance requirements include conducting performance tests according to § 63.11212 and Table 4 to this subpart, conducting a fuel analysis for each type of fuel burned in your boiler according to § 63.11213 and Table 5 to this subpart, establishing operating limits according to § 63.11222, Table 6 to this subpart and paragraph (b) of this section, as applicable, and conducting continuous monitoring system (CMS) performance evaluations according to § 63.11224. For affected boilers that burn a single type of fuel, you are exempted from the compliance requirements of conducting a fuel analysis for each type of fuel burned in your boiler. For purposes of this subpart, boilers that use a supplemental fuel only for startup, unit shutdown, and transient flame stability purposes still qualify as affected boilers that burn a single type of fuel, and the supplemental fuel is not subject to the fuel analysis requirements under § 63.11213 and Table 5 to this subpart.

(b) You must establish parameter operating limits according to paragraphs (b)(1) through (4) of this section.

(1) For a wet scrubber, you must establish the minimum liquid flowrate and pressure drop as defined in § 63.11237, as your operating limits during the three-run performance stack test. If you use a wet scrubber and you conduct separate performance stack tests for particulate matter and mercury emissions, you must establish one set of minimum scrubber liquid flowrate and pressure drop operating limits. If you conduct multiple performance stack tests, you must set the minimum liquid flowrate and pressure drop operating limits at the highest minimum values established during the performance stack tests.

(2) For an electrostatic precipitator operated with a wet scrubber, you must establish the minimum voltage and secondary amperage (or total electric power input), as defined in § 63.11237, as your operating limits during the three-run performance stack test. (These operating limits do not apply to electrostatic precipitators that are operated as dry controls without a wet scrubber.)

(3) For activated carbon injection, you must establish the minimum activated carbon injection rate, as defined in § 63.11237, as your operating limit during the three-run performance stack test.

(4) The operating limit for boilers with fabric filters that demonstrate continuous compliance through bag leak detection systems is that a bag leak detection system be installed according to the requirements in § 63.11224, and that each fabric filter must be operated such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during a 6-month period.

(c) If you elect to demonstrate compliance with an applicable mercury emission limit through fuel analysis, you must conduct fuel analyses according to § 63.11213 and Table 5 to this subpart and follow the procedures in paragraphs (c)(1) through (3) of this section.

(1) If you burn more than one fuel type, you must determine the fuel type, or mixture, you could burn in your boiler that would result in the maximum emission rates of mercury.

(2) You must determine the 90th percentile confidence level fuel mercury concentration of the composite samples analyzed for each fuel type using Equation 1 of this section.

$$P_{90} = \text{mean} + (SD * t) \quad \text{(Eq. 1)}$$

Where:

P_{90} = 90th percentile confidence level mercury concentration, in pounds per million Btu.

mean = Arithmetic average of the fuel mercury concentration in the fuel samples analyzed according to § 63.11213, in units of pounds per million Btu.

SD = Standard deviation of the mercury concentration in the fuel samples analyzed according to § 63.11213, in units of pounds per million Btu.

t = t distribution critical value for 90th percentile (0.1) probability for the appropriate degrees of freedom (number of samples minus one) as obtained from a Distribution Critical Value Table.

(3) To demonstrate compliance with the applicable mercury emission limit, the emission rate that you calculate for your boiler using Equation 1 of this section must be less than the applicable mercury emission limit.

§ 63.11212 What stack tests and procedures must I use for the performance tests?

(a) You must conduct all performance tests according to § 63.7(c), (d), (f), and (h). You must also develop a site-specific test plan according to the requirements in § 63.7(c).

(b) You must conduct each stack test according to the requirements in Table 4 to this subpart.

(c) You must conduct performance stack tests at the representative operating load conditions while burning the type of fuel or mixture of fuels that have the highest emissions potential for each regulated pollutant, and you must demonstrate initial compliance and establish your operating limits based on these performance stack tests. For subcategories with more than one emission limit, these requirements could result in the need to conduct more than one performance stack test. Following each performance stack test and until the next performance stack test, you must comply with the operating limit for operating load conditions specified in Table 3 to this subpart.

(d) You must conduct a minimum of three separate test runs for each performance stack test required in this section, as specified in § 63.7(e)(3) and in accordance with the provisions in Table 4 to this subpart.

(e) To determine compliance with the emission limits, you must use the F-Factor methodology and equations in sections 12.2 and 12.3 of EPA Method 19 of appendix A-7 to part 60 of this chapter to convert the measured particulate matter concentrations and the measured mercury concentrations that result from the initial performance test to pounds per million Btu heat input emission rates.

§ 63.11213 What fuel analyses and procedures must I use for the performance tests?

(a) You must conduct fuel analyses according to the procedures in paragraphs (b) and (c) of this section and Table 5 to this subpart, as applicable. You are not required to conduct fuel analyses for fuels used for only startup, unit shutdown, and transient flame stability purposes. You are required to conduct fuel analyses only for fuels and units that are subject to emission limits for mercury in Table 1 of this subpart.

(b) At a minimum, you must obtain three composite fuel samples for each fuel type according to the procedures in Table 5 to this subpart. Each composite sample must consist of a minimum of three samples collected at approximately equal intervals during a test run period.

(c) Determine the concentration of mercury in the fuel in units of pounds per million Btu of each composite sample for each fuel type according to the procedures in Table 5 to this subpart.

§ 63.11214 How do I demonstrate initial compliance with the work practice standard, emission reduction measures, and management practice?

(a) If you own or operate an existing or new coal-fired boiler with a heat input capacity of less than 10 million Btu per hour, you must conduct a performance tune-up according to § 63.11223(b) and you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted a tune-up of the boiler.

(b) If you own or operate an existing or new biomass-fired boiler or an existing or new oil-fired boiler, you must conduct a performance tune-up according to § 63.11223(b) and you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted a tune-up of the boiler.

(c) If you own or operate an existing affected boiler with a heat input capacity of 10 million Btu per hour or greater, you must submit a signed certification in the Notification of Compliance Status report that an energy assessment of the boiler and its energy use systems was completed and submit, upon request, the energy assessment report.

(d) If you own or operate a boiler subject to emission limits in Table 1 of this subpart, you must minimize the boiler's startup and shutdown periods following the manufacturer's recommended procedures, if available. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available. You must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted startups and shutdowns according to the manufacturer's recommended procedures or procedures specified for a boiler of similar design if manufacturer's recommended procedures are not available.

Continuous Compliance Requirements

§ 63.11220 When must I conduct subsequent performance tests?

(a) If your boiler has a heat input capacity of 10 million Btu per hour or greater, you must conduct all applicable performance (stack) tests according to § 63.11212 on an triennial basis, unless you follow the requirements listed in paragraphs (b) through (d) of this section. Triennial performance tests must be completed no more than 37 months after the previous performance test, unless you follow the requirements listed in paragraphs (b) through (d) of this section.

(b) You can conduct performance stack tests less often for particulate matter or mercury if your performance stack tests for the pollutant for at least 3 consecutive years show that your emissions are at or below 75 percent of the emission limit, and if there are no changes in the operation of the affected source or air pollution control equipment that could increase emissions. In this case, you do not have to conduct a performance stack test for that pollutant for the next 2 years. You must conduct a performance stack test during the third year and no more than 37 months after the previous performance stack test.

(c) If your boiler continues to meet the emission limit for particulate matter or mercury, you may choose to conduct performance stack tests for the pollutant every third year if your emissions are at or below 75 percent of the emission limit, and if there are no changes in the operation of the affected source or air pollution control equipment that could increase emissions, but each such performance stack test must be conducted no more than 37 months after the previous performance test.

(d) If you have an applicable CO emission limit, you must conduct triennial performance tests for CO according to § 63.11212. Each triennial performance test must be conducted between no more than 37 months after the previous performance test.

(e) If you demonstrate compliance with the mercury emission limit based on fuel analysis, you must conduct a fuel analysis according to § 63.11213 for each type of fuel burned monthly. If you plan to burn a new type of fuel or fuel mixture, you must conduct a fuel analysis before burning the new type of fuel or mixture in your boiler. You must recalculate the mercury emission rate using Equation 1 of § 63.11211. The recalculated mercury emission rate must be less than the applicable emission limit.

§ 63.11221 How do I monitor and collect data to demonstrate continuous compliance?

(a) You must monitor and collect data according to this section.

(b) You must operate the monitoring system and collect data at all required intervals at all times the affected source is operating except for periods of monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods (see section 63.8(c)(7) of this part), and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments. A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to effect monitoring system repairs in response to monitoring system malfunctions or out-of-control periods and to return the monitoring system to operation as expeditiously as practicable.

(c) You may not use data recorded during monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You must use all the data collected during all other periods in assessing the operation of the control device and associated control system.

(d) Except for periods of monitoring system malfunctions or out-of-control periods, repairs associated with monitoring system malfunctions or out-of-control periods, and required monitoring system quality assurance or quality control activities including, as applicable, calibration checks and required zero and span adjustments, failure to collect required data is a deviation of the monitoring requirements.

§ 63.11222 How do I demonstrate continuous compliance with the emission limits?

(a) You must demonstrate continuous compliance with each emission limit and operating limit in Tables 1 and 3 to this subpart that applies to you according to the methods specified in Table 7 to this subpart and to paragraphs (a)(1) through (4) of this section.

(1) Following the date on which the initial compliance demonstration is completed or is required to be completed under §§ 63.7 and 63.11196, whichever date comes first, you must continuously monitor the operating parameters. Operation above the established maximum, below the established minimum, or outside the allowable range of the operating limits specified in paragraph (a) of this section constitutes a deviation from your operating limits established under this subpart, except during performance tests conducted to determine compliance with the emission and operating limits or to establish new operating limits. Operating limits are confirmed or reestablished during performance tests.

(2) If you have an applicable mercury or PM emission limit, you must keep records of the type and amount of all fuels burned in each boiler during the reporting period to demonstrate that all fuel types and mixtures of fuels burned would result in lower emissions of mercury than the applicable emission limit (if you demonstrate compliance through fuel analysis), or result in lower fuel input of mercury than the maximum values calculated during the last performance stack test (if you demonstrate compliance through performance stack testing).

(3) If you have an applicable mercury emission limit and you plan to burn a new type of fuel, you must determine the mercury concentration for any new fuel type in units of pounds per million Btu, using the procedures in Equation 1 of § 63.11211 based on supplier data or your own fuel analysis, and meet the requirements in paragraphs (a)(3)(i) or (ii) of this section.

(i) The recalculated mercury emission rate must be less than the applicable emission limit.

(ii) If the mercury concentration is higher than mercury fuel input during the previous performance test, then you must conduct a new performance test within 60 days of burning the new fuel type or fuel mixture according to the procedures in § 63.11212 to demonstrate that the mercury emissions do not exceed the emission limit.

(4) If your unit is controlled with a fabric filter, and you demonstrate continuous compliance using a bag leak detection system, you must initiate corrective action within 1 hour of a bag leak detection system alarm and operate and maintain the fabric filter system such that the alarm does not sound more than 5 percent of the operating time during a 6-month period. You must also keep records of the date, time, and duration of each alarm, the time corrective action was initiated and completed, and a brief description of the cause of the alarm and the corrective action taken. You must also record the percent of the operating time during each 6-month period that the alarm sounds. In calculating this operating time percentage, if inspection of the fabric filter demonstrates that no corrective action is required, no alarm time is counted. If corrective action is required, each alarm is counted as a minimum of 1 hour. If you take longer than 1 hour to initiate corrective action, the alarm time is counted as the actual amount of time taken to initiate corrective action.

(b) You must report each instance in which you did not meet each emission limit and operating limit in Tables 1 and 3 to this subpart that apply to you. These instances are deviations from the emission limits in this subpart. These deviations must be reported according to the requirements in § 63.11225.

§ 63.11223 How do I demonstrate continuous compliance with the work practice and management practice standards?

(a) For affected sources subject to the work practice standard or the management practices of a tune-up, you must conduct a biennial performance tune-up according to paragraphs (b) of this section and keep records as required in § 63.11225(c) to demonstrate continuous compliance. Each biennial tune-up must be conducted no more than 25 months after the previous tune-up.

(b) You must conduct a tune-up of the boiler biennially to demonstrate continuous compliance as specified in paragraphs (b)(1) through (7) of this section.

(1) As applicable, inspect the burner, and clean or replace any components of the burner as necessary (you may delay the burner inspection until the next scheduled unit shutdown, but you must inspect each burner at least once every 36 months).

(2) Inspect the flame pattern, as applicable, and adjust the burner as necessary to optimize the flame pattern. The adjustment should be consistent with the manufacturer's specifications, if available.

(3) Inspect the system controlling the air-to-fuel ratio, as applicable, and ensure that it is correctly calibrated and functioning properly.

(4) Optimize total emissions of carbon monoxide. This optimization should be consistent with the manufacturer's specifications, if available.

(5) Measure the concentrations in the effluent stream of carbon monoxide in parts per million, by volume, and oxygen in volume percent, before and after the adjustments are made (measurements may be either on a dry or wet basis, as long as it is the same basis before and after the adjustments are made).

(6) Maintain onsite and submit, if requested by the Administrator, biennial report containing the information in paragraphs (b)(6)(i) through (iii) of this section.

(i) The concentrations of CO in the effluent stream in parts per million, by volume, and oxygen in volume percent, measured before and after the tune-up of the boiler.

(ii) A description of any corrective actions taken as a part of the tune-up of the boiler.

(iii) The type and amount of fuel used over the 12 months prior to the biennial tune-up of the boiler.

(7) If the unit is not operating on the required date for a tune-up, the tune-up must be conducted within one week of startup.

(c) If you own or operate an existing or new coal-fired boiler with a heat input capacity of 10 million Btu per hour or greater, you must minimize the boiler's time spent during startup and shutdown following the manufacturer's recommended procedures and you must submit a signed statement in the Notification of Compliance Status report that indicates that you conducted startups and shutdowns according to the manufacturer's recommended procedures.

§ 63.11224 What are my monitoring, installation, operation, and maintenance requirements?

(a) If your boiler is subject to a carbon monoxide emission limit in Table 1 to this subpart, you must install, operate, and maintain a continuous oxygen monitor according to the procedures in paragraphs (a)(1) through (6) of this section by the compliance date specified in § 63.11196. The oxygen level shall be monitored at the outlet of the boiler.

(1) Each monitor must be installed, operated, and maintained according to the applicable procedures under Performance Specification 3 at 40 CFR part 60, appendix B, and according to the site-specific monitoring plan developed according to paragraph (c) of this section.

(2) You must conduct a performance evaluation of each CEMS according to the requirements in § 63.8(e) and according to Performance Specification 3 at 40 CFR part 60, appendix B.

(3) Each CEMS must complete a minimum of one cycle of operation (sampling, analyzing, and data recording) for each successive 15-minute period.

(4) The CEMS data must be reduced as specified in § 63.8(g)(2).

(5) You must calculate and record the 12-hour block average concentrations.

(6) For purposes of calculating data averages, you must use all the data collected during all periods in assessing compliance, excluding data collected during periods when the monitoring system malfunctions or is out of control, during associated repairs, and during required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments). Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions. Any period for which the monitoring system malfunctions or is out of control and data are not available for a required calculation constitutes a deviation from the monitoring requirements. Periods when data are unavailable because of required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments) do not constitute monitoring deviations.

(b) If you are using a control device to comply with the emission limits specified in Table 1 to this subpart, you must maintain each operating limit in Table 3 to this subpart that applies to your boiler as specified in Table 7 to this subpart. If you use a control device not covered in Table 3 to this subpart, or you wish to establish and monitor an alternative operating limit and alternative monitoring parameters, you must apply to the United States Environmental Protection Agency (EPA) Administrator for approval of alternative monitoring under § 63.8(f).

(c) If you demonstrate compliance with any applicable emission limit through stack testing and subsequent compliance with operating limits, you must develop a site-specific monitoring plan according to the requirements in paragraphs (c)(1) through (4) of this section. This requirement also applies to you if you petition the EPA Administrator for alternative monitoring parameters under § 63.8(f).

(1) For each continuous monitoring system (CMS) required in this section, you must develop, and submit to the EPA Administrator for approval upon request, a site-specific monitoring plan that addresses paragraphs (b)(1)(i) through (iii) of this section. You must submit this site-specific monitoring plan (if requested) at least 60 days before your initial performance evaluation of your CMS.

(i) Installation of the CMS sampling probe or other interface at a measurement location relative to each affected unit such that the measurement is representative of control of the exhaust emissions (*e.g.,* on or downstream of the last control device).

(ii) Performance and equipment specifications for the sample interface, the pollutant concentration or parametric signal analyzer, and the data collection and reduction systems.

(iii) Performance evaluation procedures and acceptance criteria (*e.g.,* calibrations).

(2) In your site-specific monitoring plan, you must also address paragraphs (b)(2)(i) through (iii) of this section.

(i) Ongoing operation and maintenance procedures in accordance with the general requirements of § 63.8(c)(1), (3), and (4)(ii).

(ii) Ongoing data quality assurance procedures in accordance with the general requirements of § 63.8(d).

(iii) Ongoing recordkeeping and reporting procedures in accordance with the general requirements of § 63.10(c), (e)(1), and (e)(2)(i).

(3) You must conduct a performance evaluation of each CMS in accordance with your site-specific monitoring plan.

(4) You must operate and maintain the CMS in continuous operation according to the site-specific monitoring plan.

(d) If you have an operating limit that requires the use of a CMS, you must install, operate, and maintain each continuous parameter monitoring system according to the procedures in paragraphs (d)(1) through (5) of this section.

(1) The continuous parameter monitoring system must complete a minimum of one cycle of operation for each successive 15-minute period. You must have a minimum of four successive cycles of operation to have a valid hour of data.

(2) Except for monitoring malfunctions, associated repairs, and required quality assurance or control activities (including, as applicable, calibration checks and required zero and span adjustments), you must conduct all monitoring in continuous operation at all times that the unit is operating. A monitoring malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring to provide valid data. Monitoring failures that are caused in part by poor maintenance or careless operation are not malfunctions.

(3) For purposes of calculating data averages, you must not use data recorded during monitoring malfunctions, associated repairs, out of control periods, or required quality assurance or control activities. You must use all the data collected during all other periods in assessing compliance. Any period for which the monitoring system is out-of-control and data are not available for a required calculation constitutes a deviation from the monitoring requirements.

(4) Determine the 12-hour block average of all recorded readings, except as provided in paragraph (d)(3) of this section.

(5) Record the results of each inspection, calibration, and validation check.

(e) If you have an applicable opacity operating limit under this rule, you must install, operate, certify and maintain each continuous opacity monitoring system (COMS) according to the procedures in paragraphs (e)(1) through (7) of this section by the compliance date specified in § 63.11196.

(1) Each COMS must be installed, operated, and maintained according to Performance Specification 1 of 40 CFR part 60, appendix B.

(2) You must conduct a performance evaluation of each COMS according to the requirements in § 63.8 and according to Performance Specification 1 of 40 CFR part 60, appendix B.

(3) As specified in § 63.8(c)(4)(i), each COMS must complete a minimum of one cycle of sampling and analyzing for each successive 10-second period and one cycle of data recording for each successive 6-minute period.

(4) The COMS data must be reduced as specified in § 63.8(g)(2).

(5) You must include in your site-specific monitoring plan procedures and acceptance criteria for operating and maintaining each COMS according to the requirements in § 63.8(d). At a minimum, the monitoring plan must include a daily calibration drift assessment, a quarterly performance audit, and an annual zero alignment audit of each COMS.

(6) You must operate and maintain each COMS according to the requirements in the monitoring plan

and the requirements of § 63.8(e). Identify periods the COMS is out of control including any periods that the COMS fails to pass a daily calibration drift assessment, a quarterly performance audit, or an annual zero alignment audit.

(7) You must determine and record all the 1-hour block averages collected for periods during which the COMS is not out of control.

(f) If you use a fabric filter bag leak detection system to comply with the requirements of this subpart, you must install, calibrate, maintain, and continuously operate the bag leak detection system as specified in paragraphs (f)(1) through (8) of this section.

(1) You must install and operate a bag leak detection system for each exhaust stack of the fabric filter.

(2) Each bag leak detection system must be installed, operated, calibrated, and maintained in a manner consistent with the manufacturer's written specifications and recommendations and in accordance with EPA–454/R–98–015 (incorporated by reference, see § 63.14).

(3) The bag leak detection system must be certified by the manufacturer to be capable of detecting particulate matter emissions at concentrations of 10 milligrams per actual cubic meter or less.

(4) The bag leak detection system sensor must provide output of relative or absolute particulate matter loadings.

(5) The bag leak detection system must be equipped with a device to continuously record the output signal from the sensor.

(6) The bag leak detection system must be equipped with an audible or visual alarm system that will activate automatically when an increase in relative particulate matter emissions over a preset level is detected. The alarm must be located where it is easily heard or seen by plant operating personnel.

(7) For positive pressure fabric filter systems that do not duct all compartments of cells to a common stack, a bag leak detection system must be installed in each baghouse compartment or cell.

(8) Where multiple bag leak detectors are required, the system's instrumentation and alarm may be shared among detectors.

§ 63.11225 What are my notification, reporting, and recordkeeping requirements?

(a) You must submit the notifications specified in paragraphs (a)(1) through (a)(5) of this section to the delegated authority.

(1) You must submit all of the notifications in §§ 63.7(b); 63.8(e) and (f); 63.9(b) through (e); and 63.9(g) and (h) that apply to you by the dates specified in those sections.

(2) As specified in § 63.9(b)(2), you must submit the Initial Notification no later than 120 calendar days after May 20, 2011 or within 120 days after the source becomes subject to the standard.

(3) If you are required to conduct a performance stack test you must submit a Notification of Intent to conduct a performance test at least 60 days before the performance stack test is scheduled to begin.

(4) You must submit the Notification of Compliance Status in accordance with § 63.9(h) no later than 120 days after the applicable compliance date specified in § 63.11196 unless you must conduct a performance stack test. If you must conduct a performance stack test, you must submit the Notification of Compliance Status within 60 days of completing the performance stack test. In addition to the information required in § 63.9(h)(2), your notification must include the following certification(s) of compliance, as applicable, and signed by a responsible official:

(i) "This facility complies with the requirements in § 63.11214 to conduct an initial tune-up of the boiler."

(ii) "This facility has had an energy assessment performed according to § 63.11214(c)."

(iii) For an owner or operator that installs bag leak detection systems: "This facility has prepared a bag leak detection system monitoring plan in accordance with § 63.11224 and will operate each bag leak detection system according to the plan."

(iv) For units that do not qualify for a statutory exemption as provided in section 129(g)(1) of the Clean Air Act: "No secondary materials that are solid waste were combusted in any affected unit."

(5) If you are using data from a previously conducted emission test to serve as documentation of conformance with the emission standards and operating limits of this subpart consistent with § 63.7(e)(2)(iv), you must submit the test data in lieu of the initial performance test results with the Notification of Compliance Status required under paragraph (a)(4) of this section.

(b) You must prepare, by March 1 of each year, and submit to the delegated authority upon request, an annual compliance certification report for the previous calendar year containing the information specified in paragraphs (b)(1) through (4) of this section. You must submit the report by March 15 if you had any instance described by paragraph (b)(3) of this section. For boilers that are subject only to a requirement to conduct a biennial tune-up according to § 63.11223(a) and not subject to emission limits or operating limits, you may prepare only a biennial compliance report as specified in paragraphs (b)(1) through (4) of this section, instead of a semi-annual compliance report.

(1) Company name and address.

(2) Statement by a responsible official, with the official's name, title, phone number, e-mail address, and signature, certifying the truth, accuracy and completeness of the notification and a statement of whether the source has complied with all the relevant standards and other requirements of this subpart.

(3) If the source experiences any deviations from the applicable requirements during the reporting period, include a description of deviations, the time periods during which the deviations occurred, and the corrective actions taken.

(4) The total fuel use by each affected boiler subject to an emission limit, for each calendar month within the reporting period, including, but not limited to, a description of the fuel, whether the fuel has received a non-waste determination by you or EPA through a petition process to be a non-waste under § 241.3(c), whether the fuel(s) were processed from discarded non-hazardous secondary materials within the meaning of § 241.3, and the total fuel usage amount with units of measure.

(c) You must maintain the records specified in paragraphs (c)(1) through (5) of this section.

(1) As required in § 63.10(b)(2)(xiv), you must keep a copy of each notification and report that you submitted to comply with this subpart and all documentation supporting any Initial Notification or Notification of Compliance Status that you submitted.

(2) You must keep records to document conformance with the work practices, emission reduction measures, and management practices required by § 63.11214 as specified in paragraphs (c)(2)(i) and (ii) of this section.

(i) Records must identify each boiler, the date of tune-up, the procedures followed for tune-up, and the manufacturer's specifications to which the boiler was tuned.

(ii) Records documenting the fuel type(s) used monthly by each boiler, including, but not limited to, a description of the fuel, including whether the fuel has received a non-waste determination by you or EPA, and the total fuel usage amount with units of measure. If you combust non-hazardous secondary materials that have been determined not to be solid waste pursuant to § 241.3(b)(1), you must keep a record which documents how the secondary material meets each of the legitimacy criteria. If you combust a fuel that has been processed from a discarded non-hazardous secondary material pursuant to § 241.3(b)(4), you must keep records as to how the operations that produced the fuel satisfies the definition of processing in § 241.2. If the fuel received a non-waste determination pursuant to the petition process submitted under § 241.3(c), you must keep a record that documents how the fuel satisfies the requirements of the petition process.

(3) For sources that demonstrate compliance through fuel analysis, a copy of all calculations and supporting documentation that were done to demonstrate compliance with the mercury emission limits. Supporting documentation should include results of any fuel analyses. You can use the results from one fuel analysis for multiple boilers provided they are all burning the same fuel type.

(4) Records of the occurrence and duration of each malfunction of the boiler, or of the associated air pollution control and monitoring equipment.

(5) Records of actions taken during periods of malfunction to minimize emissions in accordance with the general duty to minimize emissions in § 63.11205(a), including corrective actions to restore the malfunctioning boiler, air pollution control, or monitoring equipment to its normal or usual manner of operation.

(6) You must keep the records of all inspection and monitoring data required by §§ 63.11221 and 63.11222, and the information identified in paragraphs (c)(6)(i) through (vi) of this section for each required inspection or monitoring.

(i) The date, place, and time of the monitoring event.

(ii) Person conducting the monitoring.

(iii) Technique or method used.

(iv) Operating conditions during the activity.

(v) Results, including the date, time, and duration of the period from the time the monitoring indicated a problem to the time that monitoring indicated proper operation.

(vi) Maintenance or corrective action taken (if applicable).

(7) If you use a bag leak detection system, you must keep the records specified in paragraphs (c)(7)(i) through (iii) of this section.

(i) Records of the bag leak detection system output.

(ii) Records of bag leak detection system adjustments, including the date and time of the adjustment, the initial bag leak detection system settings, and the final bag leak detection system settings.

(iii) The date and time of all bag leak detection system alarms, and for each valid alarm, the time you initiated corrective action, the corrective action taken, and the date on which corrective action was completed.

(d) Your records must be in a form suitable and readily available for expeditious review, according to § 63.10(b)(1). As specified in § 63.10(b)(1), you must keep each record for 5 years following the date of each recorded action. You must keep each record onsite for at least 2 years after the date of each recorded action according to § 63.10(b)(1). You may keep the records off site for the remaining 3 years.

(e) As of January 1, 2012 and within 60 days after the date of completing each performance test, as defined in § 63.2, conducted to demonstrate compliance with this subpart, you must submit relative accuracy test audit (i.e., reference method) data and performance test (i.e., compliance test) data, except opacity data, electronically to EPA's Central Data Exchange (CDX) by using the Electronic Reporting Tool (ERT) (*see http://www.epa.gov/ttn/chief/ert/ert tool.html/*) or other compatible electronic spreadsheet. Only data collected using test methods compatible with ERT are subject to this requirement to be submitted electronically into EPA's WebFIRE database.

(f) If you intend to commence or recommence combustion of solid waste, you must provide 30 days prior notice of the date upon which you will commence or recommence combustion of solid waste. The notification must identify:

(1) The name of the owner or operator of the affected source, the location of the source, the boiler(s) that will commence burning solid waste, and the date of the notice.

(2) The currently applicable subcategory under this subpart.

(3) The date on which you became subject to the currently applicable emission limits.

(4) The date upon which you will commence combusting solid waste.

(g) If you intend to switch fuels, and this fuel switch may result in the applicability of a different subcategory or a switch out of subpart JJJJJJ due to a switch to 100 percent natural gas, you must provide 30 days prior notice of the date upon which you will switch fuels. The notification must identify:

(1) The name of the owner or operator of the affected source, the location of the source, the boiler(s) that will switch fuels, and the date of the notice.

(2) The currently applicable subcategory under this subpart.

(3) The date on which you became subject to the currently applicable standards.

(4) The date upon which you will commence the fuel switch.

§ 63.11226 How can I assert an affirmative defense if I exceed an emission limit during a malfunction?

In response to an action to enforce the standards set forth in paragraph § 63.11201 you may assert an affirmative defense to a claim for civil penalties for exceedances of numerical emission limits that are caused by malfunction, as defined at § 63.2. Appropriate penalties may be assessed, however, if you fail to meet your burden of proving all of the requirements in the affirmative defense. The affirmative defense shall not be available for claims for injunctive relief.

(a) To establish the affirmative defense in any action to enforce such a limit, you must timely meet the notification requirements in paragraph (b) of this section, and must prove by a preponderance of evidence that:

(1) The excess emissions:

(i) Were caused by a sudden, infrequent, and unavoidable failure of air pollution control and monitoring equipment, process equipment, or a process to operate in a normal or usual manner, and

(ii) Could not have been prevented through careful planning, proper design or better operation and maintenance practices; and

(iii) Did not stem from any activity or event that could have been foreseen and avoided, or planned for; and

(iv) Were not part of a recurring pattern indicative of inadequate design, operation, or maintenance; and

(2) Repairs were made as expeditiously as possible when the applicable emission limitations were being exceeded. Off-shift and overtime labor were used, to the extent practicable to make these repairs; and

(3) The frequency, amount and duration of the excess emissions (including any bypass) were minimized to the maximum extent practicable during periods of such emissions; and

(4) If the excess emissions resulted from a bypass of control equipment or a process, then the bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and

(5) All possible steps were taken to minimize the impact of the excess

emissions on ambient air quality, the environment and human health; and

(6) All emissions monitoring and control systems were kept in operation if at all possible, consistent with safety and good air pollution control practices; and

(7) All of the actions in response to the excess emissions were documented by properly signed, contemporaneous operating logs; and

(8) At all times, the facility was operated in a manner consistent with good practices for minimizing emissions; and

(9) A written root cause analysis has been prepared, the purpose of which is to determine, correct, and eliminate the primary causes of the malfunction and the excess emissions resulting from the malfunction event at issue. The analysis shall also specify, using best monitoring methods and engineering judgment, the amount of excess emissions that were the result of the malfunction.

(b) *Notification.* The owner or operator of the facility experiencing an exceedance of its emission limit(s) during a malfunction shall notify the Administrator by telephone or facsimile (FAX) transmission as soon as possible, but no later than two business days after the initial occurrence of the malfunction, if it wishes to avail itself of an affirmative defense to civil penalties for that malfunction. The owner or operator seeking to assert an affirmative defense shall also submit a written report to the Administrator within 45 days of the initial occurrence of the exceedance of the standard in § 63.11201 to demonstrate, with all necessary supporting documentation, that it has met the requirements set forth in paragraph (a) of this section. The owner or operator may seek an extension of this deadline for up to 30 additional days by submitting a written request to the Administrator before the expiration of the 45 day period. Until a request for an extension has been approved by the Administrator, the owner or operator is subject to the requirement to submit such report within 45 days of the initial occurrence of the exceedance.

Other Requirements and Information

§ 63.11235 What parts of the General Provisions apply to me?

Table 8 to this subpart shows which parts of the General Provisions in §§ 63.1 through 63.15 apply to you.

§ 63.11236 Who implements and enforces this subpart?

(a) This subpart can be implemented and enforced by EPA or a delegated authority such as your state, local, or tribal agency. If the EPA Administrator has delegated authority to your state, local, or tribal agency, then that agency has the authority to implement and enforce this subpart. You should contact your EPA Regional Office to find out if implementation and enforcement of this subpart is delegated to your state, local, or tribal agency.

(b) In delegating implementation and enforcement authority of this subpart to a state, local, or tribal agency under 40 CFR part 63, subpart E, the authorities contained in paragraphs (c) of this section are retained by the EPA Administrator and are not transferred to the state, local, or tribal agency.

(c) The authorities that cannot be delegated to state, local, or tribal agencies are specified in paragraphs (c)(1) through (5) of this section.

(1) Approval of an alternative non-opacity emission standard and work practice standards in § 63.11223(a).

(2) Approval of alternative opacity emission standard under § 63.6(h)(9).

(3) Approval of major change to test methods under § 63.7(e)(2)(ii) and (f). A "major change to test method" is defined in § 63.90.

(4) Approval of a major change to monitoring under § 63.8(f). A "major change to monitoring" is defined in § 63.90.

(5) Approval of major change to recordkeeping and reporting under § 63.10(f). A "major change to recordkeeping/reporting" is defined in § 63.90.

§ 63.11237 What definitions apply to this subpart?

Terms used in this subpart are defined in the Clean Air Act, in § 63.2 (the General Provisions), and in this section as follows:

Affirmative defense means, in the context of an enforcement proceeding, a response or defense put forward by a defendant, regarding which the defendant has the burden of proof, and the merits of which are independently and objectively evaluated in a judicial or administrative proceeding.

Annual heat input basis means the heat input for the 12 months preceding the compliance demonstration.

Bag leak detection system means a group of instruments that is capable of monitoring particulate matter loadings in the exhaust of a fabric filter (*i.e.*, baghouse) in order to detect bag failures. A bag leak detection system includes, but is not limited to, an instrument that operates on electrodynamic, triboelectric, light scattering, light transmittance, or other principle to monitor relative particulate matter loadings.

Biomass means any biomass-based solid fuel that is not a solid waste. This includes, but is not limited to, wood residue and wood products (e.g., trees, tree stumps, tree limbs, bark, lumber, sawdust, sander dust, chips, scraps, slabs, millings, and shavings); animal manure, including litter and other bedding materials; vegetative agricultural and silvicultural materials, such as logging residues (slash), nut and grain hulls and chaff (*e.g.*, almond, walnut, peanut, rice, and wheat), bagasse, orchard prunings, corn stalks, coffee bean hulls and grounds. This definition of biomass is not intended to suggest that these materials are or are not solid waste.

Biomass subcategory includes any boiler that burns at least 15 percent biomass on an annual heat input basis.

Boiler means an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. Waste heat boilers are excluded from this definition.

Boiler system means the boiler and associated components, such as, the feedwater system, the combustion air system, the boiler fuel system (including burners), blowdown system, combustion control system, steam system, and condensate return system.

Coal means all solid fuels classifiable as anthracite, bituminous, sub-bituminous, or lignite by the American Society for Testing and Materials in ASTM D388 (incorporated by reference, see § 63.14), coal refuse, and petroleum coke. For the purposes of this subpart, this definition of "coal" includes synthetic fuels derived from coal including, but not limited to, solvent-refined coal, coal-oil mixtures, and coal-water mixtures. Coal derived gases are excluded from this definition.

Coal subcategory includes any boiler that burns any solid fossil fuel and no more than 15 percent biomass on an annual heat input basis.

Commercial boiler means a boiler used in commercial establishments such as hotels, restaurants, and laundries to provide electricity, steam, and/or hot water.

Deviation (1) Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(i) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(ii) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(2) A deviation is not always a violation. The determination of whether a deviation constitutes a violation of the standard is up to the discretion of the entity responsible for enforcement of the standards.

Dry scrubber means an add-on air pollution control system that injects dry alkaline sorbent (dry injection) or sprays an alkaline sorbent (spray dryer) to react with and neutralize acid gas in the exhaust stream forming a dry powder material. Sorbent injection systems in fluidized bed boilers are included in this definition. A dry scrubber is a dry control system.

Electrostatic precipitator (ESP) means an add-on air pollution control device used to capture particulate matter by charging the particles using an electrostatic field, collecting the particles using a grounded collecting surface, and transporting the particles into a hopper. An electrostatic precipitator is a dry control system, except when it is operated with a wet scrubber.

Energy assessment means the following only as this term is used in Table 3 to this subpart:

(1) Energy assessment for facilities with affected boilers using less than 0.3 trillion Btu (TBtu) per year heat input will be one day in length maximum. The boiler system and energy use system accounting for at least 50 percent of the affected boiler(s) energy output will be evaluated to identify energy savings opportunities, within the limit of performing a one day energy assessment.

(2) Energy assessment for facilities with affected boilers and process heaters using 0.3 to 1 TBtu/year will be three days in length maximum. The boiler system(s) and any energy use system(s) accounting for at least 33 percent of the affected boiler(s) energy output will be evaluated to identify energy savings opportunities, within the limit of performing a 3-day energy assessment.

(3) Energy assessment for facilities with affected boilers and process heaters using greater than 1.0 TBtu/year, the boiler system(s) and any energy use system(s) accounting for at least 20 percent of the affected boiler(s) energy output will be evaluated to identify energy savings opportunities.

Energy use system includes, but not limited to, process heating; compressed air systems; machine drive (motors, pumps, fans); process cooling; facility heating, ventilation, and air-conditioning (HVAC) systems; hot heater systems;, building envelop; and lighting.

Equivalent means the following only as this term is used in Table 5 to this subpart:

(1) An equivalent sample collection procedure means a published voluntary consensus standard or practice (VCS) or EPA method that includes collection of a minimum of three composite fuel samples, with each composite consisting of a minimum of three increments collected at approximately equal intervals over the test period.

(2) An equivalent sample compositing procedure means a published VCS or EPA method to systematically mix and obtain a representative subsample (part) of the composite sample.

(3) An equivalent sample preparation procedure means a published VCS or EPA method that: Clearly states that the standard, practice or method is appropriate for the pollutant and the fuel matrix; or is cited as an appropriate sample preparation standard, practice or method for the pollutant in the chosen VCS or EPA determinative or analytical method.

(4) An equivalent procedure for determining heat content means a published VCS or EPA method to obtain gross calorific (or higher heating) value.

(5) An equivalent procedure for determining fuel moisture content means a published VCS or EPA method to obtain moisture content. If the sample analysis plan calls for determining mercury using an aliquot of the dried sample, then the drying temperature must be modified to prevent vaporizing this metal. On the other hand, if metals analysis is done on an "as received" basis, a separate aliquot can be dried to determine moisture content and the mercury concentration mathematically adjusted to a dry basis.

(6) An equivalent mercury determinative or analytical procedure means a published VCS or EPA method that clearly states that the standard, practice, or method is appropriate for mercury and the fuel matrix and has a published detection limit equal or lower than the methods listed in Table 5 to this subpart for the same purpose.

Fabric filter means an add-on air pollution control device used to capture particulate matter by filtering gas streams through filter media, also known as a baghouse. A fabric filter is a dry control system.

Federally enforceable means all limitations and conditions that are enforceable by the EPA Administrator, including the requirements of 40 CFR part 60 and 40 CFR part 61, requirements within any applicable state implementation plan, and any permit requirements established under §§ 52.21 or under 51.18 and § 51.24.

Fuel type means each category of fuels that share a common name or classification. Examples include, but are not limited to, bituminous coal, sub-bituminous coal, lignite, anthracite, biomass, distillate oil, residual oil. Individual fuel types received from different suppliers are not considered new fuel types.

Gaseous fuels includes, but is not limited to, natural gas, process gas, landfill gas, coal derived gas, refinery gas, hydrogen, and biogas.

Gas-fired boiler includes any boiler that burns gaseous fuels not combined with any solid fuels, burns liquid fuel only during periods of gas curtailment, gas supply emergencies, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year.

Heat input means heat derived from combustion of fuel in a boiler and does not include the heat input from preheated combustion air, recirculated flue gases, or returned condensate.

Hot water heater means a closed vessel with a capacity of no more than 120 U.S. gallons in which water is heated by combustion of gaseous or liquid fuel and is withdrawn for use external to the vessel at pressures not exceeding 160 psig, including the apparatus by which the heat is generated and all controls and devices necessary to prevent water temperatures from exceeding 210 degrees Fahrenheit (99 degrees Celsius).

Industrial boiler means a boiler used in manufacturing, processing, mining, and refining or any other industry to provide steam, hot water, and/or electricity.

Institutional boiler means a boiler used in institutional establishments such as medical centers, research centers, and institutions of higher education to provide electricity, steam, and/or hot water.

Liquid fuel means, but not limited to, petroleum, distillate oil, residual oil, any form of liquid fuel derived from petroleum, used oil, liquid biofuels, and biodiesel.

Minimum activated carbon injection rate means load fraction (percent) multiplied by the lowest 1-hour average activated carbon injection rate measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limits.

Minimum oxygen level means the lowest 1-hour average oxygen level measured according to Table 6 of this subpart during the most recent performance stack test demonstrating compliance with the applicable CO emission limit.

Minimum PM scrubber pressure drop means the lowest 1-hour average PM scrubber pressure drop measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limit.

Minimum sorbent flow rate means the boiler load (percent) multiplied by the lowest 2-hour average sorbent (or activated carbon) injection rate measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limits.

Minimum voltage or amperage means the lowest 1-hour average total electric power value (secondary voltage × secondary current = secondary electric power) to the electrostatic precipitator measured according to Table 6 to this subpart during the most recent performance stack test demonstrating compliance with the applicable emission limits.

Natural gas means:

(1) A naturally occurring mixture of hydrocarbon and nonhydrocarbon gases found in geologic formations beneath the earth's surface, of which the principal constituent is methane including intermediate gas streams generated during processing of natural gas at production sites or at gas processing plants; or

(2) Liquefied petroleum gas, as defined by the American Society for Testing and Materials in ASTM D1835 (incorporated by reference, see § 63.14).

(3) A mixture of hydrocarbons that maintains a gaseous state at ISO conditions. Additionally, natural gas must either be composed of at least 70 percent methane by volume or have a gross calorific value between 34 and 43 megajoules (MJ) per dry standard cubic meter (910 and 1,150 Btu per dry standard cubic foot).

(4) Propane or propane-derived synthetic natural gas. Propane means a colorless gas derived from petroleum and natural gas, with the molecular structure C_3H_8.

Oil subcategory includes any boiler that burns any liquid fuel and is not in either the biomass or coal subcategories. Gas-fired boilers that burn liquid fuel during periods of gas curtailment, gas supply emergencies, or for periodic testing not to exceed 48 hours during any calendar year are not included in this definition.

Opacity means the degree to which emissions reduce the transmission of light and obscure the view of an object in the background.

Particulate matter (PM) means any finely divided solid or liquid material, other than uncombined water, as measured by the test methods specified under this subpart, or an alternative method.

Performance testing means the collection of data resulting from the execution of a test method used (either by stack testing or fuel analysis) to demonstrate compliance with a relevant emission standard.

Period of natural gas curtailment or supply interruption means a period of time during which the supply of natural gas to an affected facility is halted for reasons beyond the control of the facility. The act of entering into a contractual agreement with a supplier of natural gas established for curtailment purposes does not constitute a reason that is under the control of a facility for the purposes of this definition. An increase in the cost or unit price of natural gas does not constitute a period of natural gas curtailment or supply interruption.

Qualified energy assessor means:

(1) someone who has demonstrated capabilities to evaluate a set of the typical energy savings opportunities available in opportunity areas for steam generation and major energy using systems, including, but not limited to:

(i) Boiler combustion management.

(ii) Boiler thermal energy recovery, including

(A) Conventional feed water economizer,

(B) Conventional combustion air preheater, and

(C) Condensing economizer.

(iii) Boiler blowdown thermal energy recovery.

(iv) Primary energy resource selection, including

(A) Fuel (primary energy source) switching, and

(B) Applied steam energy versus direct-fired energy versus electricity.

(v) Insulation issues.

(vi) Steam trap and steam leak management.

(vi) Condensate recovery.

(viii) Steam end-use management.

(2) Capabilities and knowledge includes, but is not limited to:

(i) Background, experience, and recognized abilities to perform the assessment activities, data analysis, and report preparation.

(ii) Familiarity with operating and maintenance practices for steam or process heating systems.

(iii) Additional potential steam system improvement opportunities including improving steam turbine operations and reducing steam demand.

(iv) Additional process heating system opportunities including effective utilization of waste heat and use of proper process heating methods.

(v) Boiler-steam turbine cogeneration systems.

(vi) Industry specific steam end-use systems.

Responsible official means responsible official as defined in § 70.2.

Solid fossil fuel includes, but not limited to, coal, petroleum coke, and tire derived fuel.

Waste heat boiler means a device that recovers normally unused energy and converts it to usable heat. Waste heat boilers are also referred to as heat recovery steam generators.

Work practice standard means any design, equipment, work practice, or operational standard, or combination thereof, which is promulgated pursuant to section 112(h) of the Clean Air Act.

TABLE 1 TO SUBPART JJJJJJ OF PART 63—EMISSION LIMITS

[As stated in § 63.11201, you must comply with the following applicable emission limits:]

If your boiler is in this subcategory	For the following pollutants. . .	You must achieve less than or equal to the following emission limits, except during periods of startup and shutdown. . .
1. New coal-fired boiler with heat input capacity of 30 million Btu per hour or greater.	a. Particulate Matter	0.03 lb per MMBtu of heat input.
	b. Mercury	0.0000048 lb per MMBtu of heat input.
	c. Carbon Monoxide	400 ppm by volume on a dry basis corrected to 3 percent oxygen.
2. New coal-fired boiler with heat input capacity of between 10 and 30 million Btu per hour.	a. Particulate Matter	0.42 lb per MMBtu of heat input.

TABLE 1 TO SUBPART JJJJJJ OF PART 63—EMISSION LIMITS—Continued

[As stated in §63.11201, you must comply with the following applicable emission limits:]

If your boiler is in this subcategory	For the following pollutants. . .	You must achieve less than or equal to the following emission limits, except during periods of startup and shutdown. . .
	b. Mercury	0.0000048 lb per MMBtu of heat input.
	c. Carbon Monoxide	400 ppm by volume on a dry basis corrected to 3 percent oxygen.
3. New biomass-fired boiler with heat input capacity of 30 million Btu per hour or greater.	a. Particulate Matter	0.03 lb per MMBtu of heat input.
4. New biomass fired boiler with heat input capacity of between 10 and 30 million Btu per hour.	a. Particulate Matter	0.07 lb per MMBtu of heat input.
5. New oil-fired boiler with heat input capacity of 10 million Btu per hour or greater.	a. Particulate Matter	0.03 lb per MMBtu of heat input.
6. Existing coal (units with heat input capacity of 10 million Btu per hour or greater).	a. Mercury	0.0000048 lb per MMBtu of heat input.
	b. Carbon Monoxide	400 ppm by volume on a dry basis corrected to 3 percent oxygen.

TABLE 2 TO SUBPART JJJJJJ OF PART 63—WORK PRACTICE STANDARDS, EMISSION REDUCTION MEASURES, AND MANAGEMENT PRACTICES

[As stated in §63.11201, you must comply with the following applicable work practice standards, emission reduction measures, and management practices:]

If your boiler is in this subcategory. . .	You must meet the following. . .
1. Existing or new coal, new biomass, and new oil (units with heat input capacity of 10 million Btu per hour or greater).	Minimize the boiler's startup and shutdown periods following the manufacturer's recommended procedures. If manufacturer's recommended procedures are not available, you must follow recommended procedures for a unit of similar design for which manufacturer's recommended procedures are available.
2. Existing or new coal (units with heat input capacity of less than 10 million Btu per hour).	Conduct a tune-up of the boiler biennially as specified in §63.11223.
3. Existing or new biomass or oil	Conduct a tune-up of the boiler biennially as specified in §63.11223.
4. Existing coal, biomass, or oil (units with heat input capacity of 10 million Btu per hour and greater).	Must have a one-time energy assessment performed by a qualified energy assessor. An energy assessment completed on or after January 1, 2008, that meets or is amended to meet the energy assessment requirements in this table satisfies the energy assessment requirement. The energy assessment must include: (1) A visual inspection of the boiler system, (2) An evaluation of operating characteristics of the facility, specifications of energy using systems, operating and maintenance procedures, and unusual operating constraints, (3) Inventory of major systems consuming energy from affected boiler(s), (4) A review of available architectural and engineering plans, facility operation and maintenance procedures and logs, and fuel usage, (5) A list of major energy conservation measures, (6) A list of the energy savings potential of the energy conservation measures identified, (7) A comprehensive report detailing the ways to improve efficiency, the cost of specific improvements, benefits, and the time frame for recouping those investments.

TABLE 3 TO SUBPART JJJJJJ OF PART 63—OPERATING LIMITS FOR BOILERS WITH EMISSION LIMITS

[As stated in §63.11201, you must comply with the applicable operating limits:]

If you demonstrate compliance with applicable emission limits using . . .	You must meet these operating limits. . .
1. Fabric filter control	a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); OR
	b. Install and operate a bag leak detection system according to §63.11224 and operate the fabric filter such that the bag leak detection system alarm does not sound more than 5 percent of the operating time during each 6-month period.
2. Electrostatic precipitator control	a. Maintain opacity to less than or equal to 10 percent opacity (daily block average); OR
	b. Maintain the secondary power input of the electrostatic precipitator at or above the lowest 1-hour average secondary electric power measured during the most recent performance test demonstrating compliance with the particulate matter emission limitations.
3. Wet PM scrubber control	Maintain the pressure drop at or above the lowest 1-hour average pressure drop across the wet scrubber and the liquid flow-rate at or above the lowest 1-hour average liquid flow rate measured during the most recent performance test demonstrating compliance with the PM emission limitation.

TABLE 3 TO SUBPART JJJJJJ OF PART 63—OPERATING LIMITS FOR BOILERS WITH EMISSION LIMITS—Continued

[As stated in § 63.11201, you must comply with the applicable operating limits:]

If you demonstrate compliance with applicable emission limits using . . .	You must meet these operating limits. . .
4. Dry sorbent or carbon injection control	Maintain the sorbent or carbon injection rate at or above the lowest 2-hour average sorbent flow rate measured during the most recent performance test demonstrating compliance with the mercury emissions limitation. When your boiler operates at lower loads, multiply your sorbent or carbon injection rate by the load fraction (e.g., actual heat input divided by the heat input during performance stack test, for 50 percent load, multiply the injection rate operating limit by 0.5).
5. Any other add-on air pollution control type	This option is for boilers that operate dry control systems. Boilers must maintain opacity to less than or equal to 10 percent opacity (daily block average).
6. Fuel analysis	Maintain the fuel type or fuel mixture (annual average) such that the mercury emission rates calculated according to § 63.11211(b) is less than the applicable emission limits for mercury.
7. Performance stack testing	For boilers that demonstrate compliance with a performance stack test, maintain the operating load of each unit such that is does not exceed 110 percent of the average operating load recorded during the most recent performance stack test.
8. Continuous Oxygen Monitor	Maintain the oxygen level at or above the lowest 1-hour average oxygen level measured during the most recent CO performance stack test.

TABLE 4 TO SUBPART JJJJJJ OF PART 63—PERFORMANCE (STACK) TESTING REQUIREMENTS

[As stated in § 63.11212, you must comply with the following requirements for performance (stack) test for affected sources:]

To conduct a performance test for the following pollutant. . .	You must. . .	Using. . .
1. Particulate Matter	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A–1 to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A–2 to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A–2 to part 60 of this chapter, or ASTM D6522–00 (Reapproved 2005),[a] or ANSI/ASME PTC 19.10–1981.[a]
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A–3 to part 60 of this chapter.
	e. Measure the particulate matter emission concentration.	Method 5 or 17 (positive pressure fabric filters must use Method 5D) in appendix A–3 and A–6 to part 60 of this chapter and a minimum 1 dscm of sample volume per run.
	f. Convert emissions concentration to lb/MMBtu emission rates.	Method 19 F-factor methodology in appendix A–7 to part 60 of this chapter.
2. Mercury	a. Select sampling ports location and the number of traverse points.	Method 1 in appendix A–1 to part 60 of this chapter.
	b. Determine velocity and volumetric flow-rate of the stack gas.	Method 2, 2F, or 2G in appendix A–2 to part 60 of this chapter.
	c. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A–2 to part 60 of this chapter, or ASTM D6522–00 (Reapproved 2005),[a] or ANSI/ASME PTC 19.10–1981.[a]
	d. Measure the moisture content of the stack gas.	Method 4 in appendix A–3 to part 60 of this chapter.
	e. Measure the mercury emission concentration.	Method 29, 30A, or 30B in appendix A–8 to part 60 of this chapter or Method 101A in appendix B to part 61 of this chapter or ASTM Method D6784–02.[a] Collect a minimum 2 dscm of sample volume with Method 29 of 101A per run. Use a minimum run time of 2 hours with Method 30A.
	f. Convert emissions concentration to lb/MMBtu emission rates.	Method 19 F-factor methodology in appendix A–7 to part 60 of this chapter.
3. Carbon Monoxide	a. Select the sampling ports location and the number of traverse points.	Method 1 in appendix A–1 to part 60 of this chapter.
	b. Determine oxygen and carbon dioxide concentrations of the stack gas.	Method 3A or 3B in appendix A–2 to part 60 of this chapter, or ASTM D6522–00 (Reapproved 2005),[a] or ANSI/ASME PTC 19.10–1981.[a]
	c. Measure the moisture content of the stack gas.	Method 4 in appendix A–3 to part 60 of this chapter.

Table 4 to Subpart JJJJJJ of Part 63—Performance (Stack) Testing Requirements—Continued

[As stated in § 63.11212, you must comply with the following requirements for performance (stack) test for affected sources:]

To conduct a performance test for the following pollutant. . .	You must. . .	Using. . .
	d. Measure the carbon monoxide emission concentration.	Method 10, 10A, or 10B in appendix A–4 to part 60 of this chapter or ASTM D6522–00 (Reapproved 2005) [a] and a minimum 1 hour sampling time per run.

[a] Incorporated by reference, see § 63.14.

Table 5 to Subpart JJJJJJ of Part 63—Fuel Analysis Requirements

[As stated in § 63.11213, you must comply with the following requirements for fuel analysis testing for affected sources:]

To conduct a fuel analysis for the following pollutant . . .	You must. . .	Using . . .
1. Mercury	a. Collect fuel samples	Procedure in § 63.11213(b) or ASTM D2234/D2234M [a] (for coal) or ASTM D6323 [a] (for biomass) or equivalent.
	b. Compose fuel samples	Procedure in § 63.11213(b) or equivalent.
	c. Prepare composited fuel samples	EPA SW–846–3050B [a] (for solid samples) or EPA SW–846–3020A [a] (for liquid samples) or ASTM D2013/D2013M [a] (for coal) or ASTM D5198 [a] (for biomass) or equivalent.
	d. Determine heat content of the fuel type	ASTM D5865 [a] (for coal) or ASTM E711 [a] (for biomass) or equivalent.
	e. Determine moisture content of the fuel type	ASTM D3173 [a] or ASTM E871 [a] or equivalent.
	f. Measure mercury concentration in fuel sample	ASTM D6722 [a] (for coal) or EPA SW–846–7471B [a] (for solid samples) or EPA SW–846–7470A [a] (for liquid samples) or equivalent.
	g. Convert concentrations into units of lb/MMBtu of heat content	

[a] Incorporated by reference, see § 63.14.

Table 6 to Subpart JJJJJJ of Part 63—Establishing Operating Limits

[As stated in § 63.11211, you must comply with the following requirements for establishing operating limits:]

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must. . .	Using. . .	According to the following requirements
1. Particulate matter or mercury.	a. Wet scrubber operating parameters.	i. Establish a site-specific minimum pressure drop and minimum flow rate operating limit according to § 63.11211(b).	(1) Data from the pressure drop and liquid flow rate monitors and the particulate matter or mercury performance stack test.	(a) You must collect pressure drop and liquid flow-rate data every 15 minutes during the entire period of the performance stack tests;
	(b) Determine the average pressure drop and liquid flow-rate for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run..			
	b. Electrostatic precipitator operating parameters (option only for units that operate wet scrubbers).	i. Establish a site-specific minimum secondary electric power according to § 63.11211(b).	(1) Data from the secondary electric power monitors during the particulate matter or mercury performance stack test.	(a) You must collect secondary electric power input data every 15 minutes during the entire period of the performance stack tests; (b) Determine the secondary electric power input for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.

TABLE 6 TO SUBPART JJJJJJ OF PART 63—ESTABLISHING OPERATING LIMITS—Continued

[As stated in § 63.11211, you must comply with the following requirements for establishing operating limits:]

If you have an applicable emission limit for . . .	And your operating limits are based on . . .	You must. . .	Using. . .	According to the following requirements
2. Mercury	a. Activated carbon injection.	i. Establish a site-specific minimum activated carbon injection rate operating limit according to § 63.11211(b).	(1) Data from the activated carbon rate monitors and mercury performance stack tests.	(a) You must collect activated carbon injection rate data every 15 minutes during the entire period of the performance stack tests; (b) Determine the average activated carbon injection rate for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run. (c) When your unit operates at lower loads, multiply your activated carbon injection rate by the load fraction (e.g., actual heat input divided by heat input during performance stack test, for 50 percent load, multiply the injection rate operating limit by 0.5) to determine the required injection rate.
3. Carbon monoxide	a. Oxygen	i. Establish a unit-specific limit for minimum oxygen level according to § 63.11211(b).	(1) Data from the oxygen monitor specified in § 63.11224(a).	(a) You must collect oxygen data every 15 minutes during the entire period of the performance stack tests; (b) Determine the average oxygen concentration for each individual test run in the three-run performance stack test by computing the average of all the 15-minute readings taken during each test run.

TABLE 7 TO SUBPART DDDDD OF PART 63—DEMONSTRATING CONTINUOUS COMPLIANCE

[As stated in § 63.11222, you must show continuous compliance with the emission limitations for affected sources according to the following:]

If you must meet the following operating limits. . .	You must demonstrate continuous compliance by. . .
1. Opacity	a. Collecting the opacity monitoring system data according to § 63.11224(e) and § 63.11221; and b. Reducing the opacity monitoring data to 6-minute averages; and c. Maintaining opacity to less than or equal to 10 percent (daily block average).
2. Fabric filter bag leak detection operation	Installing and operating a bag leak detection system according to § 63.11224 and operating the fabric filter such that the requirements in § 63.11222(a)(4) are met.
3. Wet scrubber pressure drop and liquid flow-rate.	a. Collecting the pressure drop and liquid flow rate monitoring system data according to §§ 63.11224 and 63.11221; and b. Reducing the data to 12-hour block averages; and c. Maintaining the 12-hour average pressure drop and liquid flow-rate at or above the operating limits established during the performance test according to § 63.1140.
4. Dry scrubber sorbent or carbon injection rate	a. Collecting the sorbent or carbon injection rate monitoring system data for the dry scrubber according to §§ 63.11224 and 63.11220; and b. Reducing the data to 12-hour block averages; and c. Maintaining the 12-hour average sorbent or carbon injection rate at or above the minimum sorbent or carbon injection rate as defined in § 63.11237.
5. Electrostatic precipitator secondary amperage and voltage, or total power input.	a. Collecting the secondary amperage and voltage, or total power input monitoring system data for the electrostatic precipitator according to §§ 63.11224 and 63.11220; and b. Reducing the data to 12-hour block averages; and c. Maintaining the 12-hour average secondary amperage and voltage, or total power input at or above the operating limits established during the performance test according to § 63.11214.
6. Fuel pollutant content	a. Only burning the fuel types and fuel mixtures used to demonstrate compliance with the applicable emission limit according to § 63.11214 as applicable; and b. Keeping monthly records of fuel use according to § 63.11222.
7. Oxygen content	a. Continuously monitor the oxygen content in the combustion exhaust according to § 63.11224. b. Maintain the 12-hour average oxygen content at or above the operating limit established during the most recent carbon monoxide performance test.

TABLE 8 TO SUBPART JJJJJJ OF PART 63—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART JJJJJJ

[As stated in § 63.11235, you must comply with the applicable General Provisions according to the following:]

General provisions cite	Subject	Does it apply?
§ 63.1	Applicability	Yes.
§ 63.2	Definitions	Yes. Additional terms defined in § 63.11237.
§ 63.3	Units and Abbreviations	Yes.
§ 63.4	Prohibited Activities and Circumvention	Yes.
§ 63.5	Preconstruction Review and Notification Requirements.	No
§ 63.6(a), (b)(1)–(b)(5), (b)(7), (c), (f)(2)–(3), (g), (i), (j)	Compliance with Standards and Maintenance Requirements.	Yes.
§ 63.6(e)(1)(i)	General Duty to minimize emissions	No. *See* § 63.11205 for general duty requirement.
§ 63.6(e)(1)(ii)	Requirement to correct malfunctions ASAP.	No.
§ 63.6(e)(3)	SSM Plan	No.
§ 63.6(f)(1)	SSM exemption	No.
§ 63.6(h)(1)	SSM exemption	No.
§ 63.6(h)(2) to (9)	Determining compliance with opacity emission standards.	Yes.
§ 63.7(a), (b), (c), (d) , (e)(2)–(e)(9), (f), (g), and (h)	Performance Testing Requirements	Yes.
§ 63.7(e)(1)	Performance testing	No. *See* § 63.11210.
§ 63.8(a), (b), (c)(1), (c)(1)(ii), (c)(2) to (c)(9), (d)(1) and (d)(2), (e),(f), and (g).	Monitoring Requirements	Yes.
§ 63.8(c)(1)(i)	General duty to minimize emissions and CMS operation.	No.
§ 63.8(c)(1)(iii)	Requirement to develop SSM Plan for CMS.	No.
§ 63.8(d)(3)	Written procedures for CMS	Yes, except for the last sentence, which refers to an SSM plan. SSM plans are not required.
§ 63.9	Notification Requirements	Yes.
§ 63.10(a) and (b)(1)	Recordkeeping and Reporting Requirements.	Yes.
§ 63.10(b)(2)(i)	Recordkeeping of occurrence and duration of startups or shutdowns.	No.
§ 63.10(b)(2)(ii)	Recordkeeping of malfunctions	No. *See* § 63.11225 for recordkeeping of (1) occurrence and duration and (2) actions taken during malfunctions.
§ 63.10(b)(2)(iii)	Maintenance records	Yes.
§ 63.10(b)(2)(iv) and (v)	Actions taken to minimize emissions during SSM.	No.
§ 63.10(b)(2)(vi)	Recordkeeping for CMS malfunctions	Yes.
§ 63.10(b)(2)(vii) to (xiv)	Other CMS requirements	Yes.
§ 63.10(b)(3)	Recordkeeping requirements for applicability determinations.	No.
§ 63.10(c)(1) to (9)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(10)	Recording nature and cause of malfunctions.	No. *See* § 63.11225 for malfunction recordkeeping requirements.
§ 63.10(c)(11)	Recording corrective actions	No. *See* § 63.11225 for malfunction recordkeeping requirements.
§ 63.10(c)(12) and (13)	Recordkeeping for sources with CMS	Yes.
§ 63.10(c)(15)	Allows use of SSM plan	No.
§ 63.10(d)(1) and (2)	General reporting requirements	Yes.
§ 63.10(d)(3)	Reporting opacity or visible emission observation results.	No.
§ 63.10(d)(4)	Progress reports under an extension of compliance.	Yes.
§ 63.10(d)(5)	SSM reports	No. *See* § 63.11225 for malfunction reporting requirements.
§ 63.10(e) and (f)		Yes.
§ 63.11	Control Device Requirements	No.
§ 63.12	State Authority and Delegation	Yes.
§ 63.13–63.16	Addresses, Incorporation by Reference, Availability of Information, Performance Track Provisions.	Yes.
§ 63.1(a)(5), (a)(7)–(a)(9), (b)(2), (c)(3)–(4), (d), 63.6(b)(6), (c)(3), (c)(4), (d), (e)(2), (e)(3)(ii), (h)(3), (h)(5)(iv), 63.8(a)(3), 63.9(b)(3), (h)(4), 63.10(c)(2)–(4), (c)(9).	Reserved	No.

[FR Doc. 2011–4493 Filed 3–18–11; 8:45 am]

BILLING CODE 6560–50–P

a chance to comment on EPA's determination after the effective date, and EPA will consider any comments received in determining whether to reverse such action.

EPA believes that notice-and-comment rulemaking before the effective date of this action is impracticable and contrary to the public interest. EPA has reviewed the State's submittal and, through its proposed action, is indicating that it is more likely than not that the State is no longer obligated to submit the plan that was the basis for the finding that started the sanctions clocks. Therefore, it is not in the public interest to impose sanctions. Moreover, it would be impracticable to go through notice-and-comment rulemaking on a finding that the State no longer is required to submit the plan prior to the rulemaking approving the State's termination determination. Therefore, EPA believes that it is necessary to use the interim final rulemaking process to defer sanctions while EPA completes its rulemaking process on the approvability of the State's submittal. Moreover, with respect to the effective date of this action, EPA is invoking the good cause exception to the 30-day notice requirement of the APA because the purpose of this notice is to relieve a restriction (5 U.S.C. 553(d)(1)).

Note that today's action has no impact on the January 5, 2010 (75 FR 232) findings regarding the Southeast Desert and the Los Angeles-South Coast Air Basin.

III. Statutory and Executive Order Reviews

This action defers Federal sanctions and imposes no additional requirements.

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is not a "significant regulatory action" and therefore is not subject to review by the Office of Management and Budget.

This action is not subject to Executive Order 13211, "Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use" (66 FR 28355, May 22, 2001) because it is not a significant regulatory action.

The administrator certifies that this action will not have a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*).

This rule does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4).

This rule does not have Tribal implications because it will not have a substantial direct effect on one or more Indian Tribes, on the relationship between the Federal government and Indian Tribes, or on the distribution of power and responsibilities between the Federal government and Indian Tribes, as specified by Executive Order 13175 (65 FR 67249, November 9, 2000).

This action does not have Federalism implications because it does not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132 (64 FR 43255, August 10, 1999).

This rule is not subject to Executive Order 13045, "Protection of Children from Environmental Health Risks and Safety Risks" (62 FR 19885, April 23, 1997), because it is not economically significant.

The requirements of section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272) do not apply to this rule because it imposes no standards.

This rule does not impose an information collection burden under the provisions of the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*).

The Congressional Review Act, 5 U.S.C. 801 *et seq.*, as added by the Small Business Regulatory Enforcement Fairness Act of 1996, generally provides that before a rule may take effect, the agency promulgating the rule must submit a rule report to Congress and the Comptroller General. However, section 808 provides that any rule for which the issuing agency for good cause finds that notice and public procedure thereon are impracticable, unnecessary, or contrary to the public interest, shall take effect at such time as the agency promulgating the rule determines. 5 U.S.C. 808(2). EPA has made such a good cause finding, including the reasons therefore, and established an effective date of May 18, 2011. EPA will submit a report containing this rule and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States prior to publication of the rule in the Federal Register. A major rule cannot take effect until 60 days after it is published in the Federal Register. This rule is not a "major rule" as defined by 5 U.S.C. 804(2).

Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by July 18, 2011. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this rule for the purpose of judicial review nor does it extend the time within which petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action may not be challenged later in proceedings to enforce its requirements (see section 307(b)(2)).

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Intergovernmental regulations, Ozone, Reporting and recordkeeping requirements.

Dated: May 9, 2011.

Jared Blumenfeld,

Regional Administrator, Region IX.

[FR Doc. 2011–12062 Filed 5–17–11; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2002–0058; EPA–HQ–2003–0119; FRL–9308–6]

RIN 2060–AQ25; 2060–AO12

Industrial, Commercial, and Institutional Boilers and Process Heaters and Commercial and Industrial Solid Waste Incineration Units

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rules; Delay of effective dates.

SUMMARY: The EPA is delaying the effective dates for the final rules titled "National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters" and "Standards of Performance for New Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Units" under the authority of the Administrative Procedure Act (APA) until the proceedings for judicial review of these rules are completed or the EPA completes its reconsideration of the rules, whichever is earlier.

DATES: The effective dates of the final rules published in the Federal Register on March 21, 2011 (76 FR 15608 and 76 FR 15704), are delayed until such time as judicial review is no longer pending or until the EPA completes its reconsideration of the rules, whichever is earlier. The Director of the Federal Register has reviewed certain publications listed in these final rules for incorporation by reference approval. That approval is delayed until such time as the proceedings for judicial review of these rules are completed or the EPA completes its reconsideration of the rules, whichever is earlier. The EPA will publish in the **Federal Register** announcing the effective dates and the incorporation by reference approvals once delay is no longer necessary.

ADDRESSES: *Docket:* The final rules, the petitions for reconsideration, and all other documents in the record for the rulemakings are in Docket ID. No. EPA–HQ–OAR–2002–0058 and EPA–HQ–OAR–2003–0119. All documents in the dockets are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.*, Confidential Business Information or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *http://www.regulations.gov* or in hard copy at the EPA's Docket Center, Public Reading Room, EPA West Building, Room 3334, 1301 Constitution Avenue, NW., Washington, DC 20004. This Docket Facility is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1741.

FOR FURTHER INFORMATION CONTACT: "National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters": Mr. Brian Shrager, Energy Strategies Group, Sector Policies and Programs Division, Office of Air Quality Planning and Standards (D243–01), U.S. Environmental Protection Agency, Research Triangle Park, NC 27711, telephone (919) 541–7689, fax number (919) 541–5450, e-mail address: *shrager.brian@epa.gov*. "Standards of Performance for New Sources and Emission Guidelines for Existing Sources: Commercial and Industrial Solid Waste Incineration Units": Ms. Toni Jones, Fuels and Incineration Group, Sector Policies and Programs Division, Office of Air Quality Planning and Standards (E143–03), U.S. Environmental Protection Agency, Research Triangle Park, NC 27711, telephone (919) 541–0316, fax number (919) 541–3470, e-mail address: *jones.toni@epa.gov*.

SUPPLEMENTARY INFORMATION:

I. Background

On March 21, 2011, the EPA issued a final rule to regulate emissions of hazardous air pollutants (HAP) from industrial, commercial, and institutional boilers and process heaters located at major sources of HAP emissions (the "Major Source Boiler MACT"). On the same date, the EPA issued a final rule to regulate emissions of certain air pollutants from commercial and industrial solid waste incineration units (the "CISWI Rule"). For further information on the Major Source Boiler MACT, *see* 76 FR 15608 (March 21, 2011). For further information on the CISWI Rule, *see* 76 FR 15704 (March 21, 2011). In the March 21 notices, the EPA established an effective date of May 20, 2011, for each rule.

On the same day the rules were issued, the EPA also published a notice explaining that the Agency was in the process of developing a notice proposing reconsideration of certain aspects of both rules. 76 FR 15267. In that notice, the EPA explained that the proposed reconsideration would address issues on which the EPA believes further opportunity for public comment is appropriate, as well as any provisions of the rules that the EPA believes warrant modification after further consideration of the data and comments already received. The EPA has received petitions from a number of interested parties seeking reconsideration of both rules. The petitions identify specific issues that the EPA is being asked to reconsider. The EPA intends to initiate a reconsideration process for both rules, as explained above. The EPA will issue a notice of proposed reconsideration of each rule that identifies the specific issue or issues raised in the petitions on which the Agency is granting reconsideration. The EPA understands that members of the public may wish to submit additional data and information to inform the EPA's proposed reconsideration, and the Agency will consider any additional information submitted in time to do so. Given the anticipated schedule for the reconsideration process, we request that any additional data and information be provided to the EPA by July 15, 2011, to allow the Agency to fully consider it.

The EPA has also received petitions for judicial review of the Major Source Boiler MACT from the United States Sugar Corporation as well as from a coalition of industry groups. The EPA has received a petition for judicial review of the CISWI Rule from a coalition of industry groups as well. Under section 705 of the APA, "an agency * * * may postpone the effective date of [an] action taken by it pending judicial review." The provision requires that the Agency find that justice requires postponing the action, that the action has not gone into effect, and that litigation is pending. As described above, neither the Major Source Boiler MACT nor the CISWI Rule has gone into effect and petitions for judicial review of both rules have been filed.

We find that justice requires postponing the effectiveness of these rules. As explained in the March 21, 2011, notice, EPA has identified several issues in the final rules which it intends to reconsider because we believe the public did not have a sufficient opportunity to comment on certain revisions EPA made to the proposed rules. These issues include revisions to the proposed subcategories and revisions to some of the proposed emissions limits. In addition, EPA received data before finalizing both rules but was unable to incorporate that data into the final rules given the court deadline for issuing the rules, which the Agency was unable to extend. EPA also notes thousands of facilities across multiple, diverse industries will need to begin to make major compliance investments soon, in light of the pressing compliance deadlines. These investments may not be reversible if the standards are in fact revised following reconsideration and full evaluation of all relevant data.

Finally, the EPA notes that it is delaying the effective date of the Major Source Boiler MACT and the CISWI Rule pursuant to the APA, rather than section 307(d)(7)(B) of the Clean Air Act. As explained above, the APA authorizes the EPA to find that justice requires postponing the effective date of a rule when litigation is pending. In contrast, the Clean Air Act authorizes the EPA to stay the effectiveness of a rule for three months if the Administrator has convened a proceeding to reconsider the rule. The EPA further notes that section 307(d) of the Act expressly states that it is intended to replace only sections 553–557 of the APA (except as otherwise provided in section 307(d)), and does not state that it replaces section 705 of the APA. Therefore, the EPA has the discretion to decide whether it is appropriate to delay the effective date of a rule under either provision, based on the specific facts and circumstances before the Agency. Since petitions for judicial review of both the Major Source Boiler MACT and the CISWI Rule have been filed, and, as explained above, justice requires a delay of the effective dates, it is reasonable for the EPA to exercise its authority to delay the effective dates of the Major Source Boiler MACT and the CISWI Rule under the APA for a period that exceeds three months.

II. Issuance of a Stay and Delay of Effective Date

Pursuant to section 705 of the APA, the EPA hereby postpones the effectiveness of the Major Source Boiler MACT and the CISWI Rule until the proceedings for judicial review of these rules are complete or the EPA completes its reconsideration of the rules, whichever is earlier. By this action, we are delaying the effective date of both rules, published in the Federal Register on March 21, 2011 (76 FR 15608 and 76 FR 15704). The delay of the effective date of the CISWI Rule applies only to those provisions issued on March 21, 2011, and not to any provisions of 40 CFR part 60, subparts CCCC and DDDD, in place prior to that date. This delay of effectiveness will remain in place until the proceedings for judicial review are completed or the EPA completes its reconsideration of the rules, whichever is earlier, and the Agency publishes a notice in the **Federal Register** announcing that the rules are in effect.

List of Subjects

40 CFR Part 60

Environmental protection, Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

40 CFR Part 63

Environmental protection, Administrative practice and procedure, Air pollution control, Hazardous substances, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

For the reasons set forth above, under the authority at 7 U.S.C. 705, the effective dates of FRL 9272–8, 76 FR 15608 (March 21, 2011), and FRL 9273–4, 76 FR 15704 (March 21, 2011) are delayed until further notice.

Dated: May 16, 2011.

Lisa P. Jackson,

Administrator.

[FR Doc. 2011–12308 Filed 5–17–11; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[OAR–2004–0080, FRL–9306–8]

RIN 2060–AF00

Method 301—Field Validation of Pollutant Measurement Methods From Various Waste Media

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action amends EPA's Method 301, Field Validation of Pollutant Measurement Methods from Various Waste Media. We revised the procedures in Method 301 based on our experience in applying the method and to correct errors that were brought to our attention. The revised Method 301 is more flexible, less expensive, and easier to use. This action finalizes amendments to Method 301 after considering comments received on the proposed rule published in the **Federal Register** on December 22, 2004.

DATES: This final rule is effective on May 18, 2011.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2004–0080. All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.*, confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically at *http://www.regulations.gov* or in hard copy at the Air Docket, EPA/DC, EPA West, Room 3334, 1301 Constitution Avenue, NW., Washington, DC. The Docket Facility and the Public Reading Room are open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Ms. Lula H. Melton, Office of Air Quality Planning and Standards, Air Quality Assessment Division, Measurement Technology Group (E143–02), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–2910; fax number: (919) 541–0516; e-mail address: *melton.lula@epa.gov*.

SUPPLEMENTARY INFORMATION:

Table of Contents

I. General Information

A. Does this action apply to me?

Method 301 affects/applies to you if you want to propose a new or alternative test method to meet an EPA compliance requirement.

B. Where can I obtain a copy of this action?

In addition to being available in the docket, an electronic copy of this rule will also be available on the Worldwide Web (www) through the Technology Transfer Network (TTN). Following the Administrator's signature, a copy of the final rule will be placed on the TTN's policy and guidance page for newly proposed or promulgated rules at *http://www.epa.gov/ttn/oarpg*. The TTN provides information and technology exchange in various areas of air pollution control. A redline strikeout

ERG

MEMORANDUM

TO: Brian Shrager, U.S. Environmental Protection Agency, OAQPS/SPPD

FROM: Amanda Singleton, and Graham Gibson, ERG

DATE: February 17, 2011

SUBJECT: Revised Methodology for Estimating Cost and Emissions Impacts for Industrial, Commercial, Institutional Boilers and Process Heaters National Emission Standards for Hazardous Air Pollutants – Major Source

1.0 INTRODUCTION

The purpose of this memorandum is to discuss the revised methodology used to estimate the costs, emission reductions, and secondary impacts from industrial, commercial, and institutional boilers at major sources of hazardous air pollutants (HAP). These impacts were calculated for existing units and new units projected to be operational by the year 2013, three years after the rule is expected to be promulgated. The results of the impacts analysis are presented for both the regulatory option contained in the promulgated rule and a more stringent regulatory option. The development of the maximum achievable control technology (MACT) floor level of control, projection of new units, and a detailed description of the cost equations used to estimate costs for various control technologies is presented in other memoranda.[1,2,3] This memorandum is organized as follows:

1.0 Introduction
2.0 Overview of Regulatory Options
3.0 Estimating Cost Impacts
4.0 Methodology for Estimating Emission Reductions
5.0 Methodology for Estimating Secondary Impacts
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2.0 OVERVIEW OF REGULATORY OPTIONS

Two control options were considered for existing boilers and process heaters at major sources of HAP. A description of the two options is included in this section.

2.1 Existing Units

- The recommended option is the option presented in the preamble and final rule. In this option, small boilers and process heaters (less than 10 mmBtu per her), limited use boilers and process heaters (operating less than 876 hours per year), and boilers burning natural gas, refinery gas, or other on-spec gaseous fuels are subject to work practice standards in lieu of numeric emission limitations. The work practice standard small and limited use units is a biennial tune-up and the work practice standard for larger natural gas, refinery gas, or other on-spec gaseous fuels is an annual boiler tune-up. Boilers not meeting one of those criteria are subject to numeric emission limitations for Hg, PM, HCl, CO, and TEQ dioxins/furans. Boilers combusting at least 10 percent solid fuels, either coal, other fossil solids or biomass are grouped into a single solid fuel subcategory and are subject to identical emission limitations for the fuel-based pollutants Hg, PM, and HCl. For combustion-based pollutants CO, and TEQ dioxins/furans separate combustor design subcategories are considered for coal/fossil solids and biomass. Units designed to burn liquid fuels, units located in non-continental States and United States Territories designed to burn liquid fuels, and units burning off-spec gaseous fuels (other process gases) each have a single subcategory for both fuel and combustor-based HAP.

- The alternative option is identical to the recommended option except that boilers combusting at least 10 percent solid fuels are subject to separate numeric limits depending on the class of solid fuel combusted. Units burning coal or other fossil solids have separate numeric emission limitations from units burning biomass or other bio-based solids for Hg, PM, and HCl.

2.2 New Units

The same two control options for existing units were used for new units. However, since it is projected that no new boilers combusting solid fuel (biomass or coal) will be constructed by 2013, the results of the cost and emission impacts analyses for both options are identical.

3.0 ESTIMATING COST IMPACTS

For each option, the cost impacts analysis compares the baseline emissions for each unit to the corresponding MACT floor emission limit for the unit's subcategory. A control device was applied to the unit if its baseline emissions exceeded their applicable MACT floor emission limit.

A comparison of the overall capital and annualized costs of the recommended option are presented in Table 1. The detailed equations used to estimate the control, testing, monitoring, and work practice costs are discussed in another memorandum.[2] The following logic was used to apply control, testing, and monitoring costs to each boiler or process heater:

3.1 Recommended Option

The recommended option represents an option with a consolidated subcategory for fuel-based HAP from solid fuel units, where every unit must meet numerical emission limits and demonstrate compliance with performance stack testing, monitoring, and fuel analysis with a few exceptions. Units in the gas 1 subcategory, small units (less than 10 mmBtu/hr), and limited use units (less than 876 operating hours per year), qualify for work practices under Section 112(h) of the CAA and work practices consisting of an annual or biennial tune-up replace the traditional compliance demonstrations associated with numeric emission limits.

Control Cost Impacts

Mercury Control

- Fabric filters — a new fabric filter installation was expected to achieve most of the Hg emission limits in the final rule. Where baseline Hg emissions were found to be greater than the MACT floor, the cost of a fabric filter was estimated for an individual boiler or process heater, unless the unit already had a fabric filter installed. A new fabric filter was estimated to be installed at 454 existing boilers and process heaters. This does not include the fabric filters installed in combination with dry injection to achieve HCl controls that are discussed below.
- Activated carbon injection (ACI) — In the case of a unit with a fabric filter emitting Hg above the MACT floor emission limit, the incremental Hg removal efficiency required to meet the MACT floor was calculated, and then the costs to install activated carbon injection (ACI) technology on the boiler were estimated. Incremental ACI equipment was installed for 108 existing boilers and process heaters.
- Wet scrubbers—one of the technologies selected for the cost analysis to reduce emissions of hydrogen chloride (HCl)—is also capable of achieving modest reductions in Hg. Literature suggests that these scrubbers can achieve a 10-percent reduction in Hg

emissions. If a scrubber was being installed for HCl, and baseline Hg emissions were within 10 percent of the MACT floor, the wet scrubber was expected to achieve this level of emission reduction without installing a fabric filter.

Particulate Matter Control

- When baseline particulate (PM) emissions exceeded the MACT floor, the cost of an ESP was estimated, unless a fabric filter had already been included in the cost analysis for Hg reduction. ESP technology was estimated to be installed at 10 existing boilers and process heaters.
- Wet scrubbers are also capable of achieving a modest reduction in PM. Literature suggests that these scrubbers can achieve an 85-percent reduction in PM emissions. If a scrubber was being installed for HCl, and baseline PM emissions were within 85 percent of the MACT floor for PM, the wet scrubber was expected to achieve this level of emission reduction without installing an ESP.

Hydrogen Chloride Control

- When HCl baseline emissions were greater than the MACT floor, the cost of adding a packed bed scrubber, increasing the sorbent rate on an existing scrubber, or installing a combination fabric filter and dry injection (DIFF) system was estimated. Scrubbers and DIFF were estimated to be able to attain similar levels of hydrogen chloride control. Based on input received during the public comment period, many wood product facilities are not permitted to discharge wastewater, thereby restricting the type of controls needed to reduce emissions of HCl and other acid gases. For this analysis, facilities in NAICS codes 321 (wood products manufacturing) and 322 (paper manufacturing) were assumed to not be able to install a packed scrubber due to the regulation of wastewater discharge from those industries. For the remaining units requiring control device installation for hydrogen chloride reduction, the less expensive control option between a packed scrubber and DIFF was assumed to be the control installed. If the boiler already reported having a scrubber installed, a DIFF was not the selected control technology, and the baseline emissions still exceeded the floor, the incremental required HCl removal efficiency was calculated and the then the cost to increase the sorbent injection rate in the scrubber was estimated in the cost analysis. Wet scrubbers were estimated to be necessary to control HCl emissions at 774 existing boilers and process heaters. DIFF was identified to be necessary to control HCl emissions at 136 existing boilers and process heaters. Incremental sorbent injection was identified to be necessary to control HCl emissions at 7 existing boilers and process heaters.

- Since the fabric filter portion of a DIFF will achieve reductions in both HCl and Hg, the analysis first checked for whether a DIFF was necessary to achieve HCl reductions, and if so, this DIFF was assumed to achieve the MACT floor limits for both HCl and Hg. If a DIFF was not needed for HCl control, but a fabric filter was needed for mercury control, the costs of a fabric filter were estimated.

Dioxin/Furan Control

The final rule requires all units that measure dioxin data below the method detection level to report that congener as zero. Based on the reported dioxin/furan data and associated detection levels available at the time of the final rule, most units will fall below the MACT floor levels if the non-detect congeners are treated as zero, For coal, 17 of the 27 tests would meet the existing limits, 17 of the 22 tests for biomass would meet the existing limits, and all of the liquid and process gas tests would meet the existing limits. Given these results and the fact that some units are installing ACI for mercury control, which is expected to have a co-benefit of reducing dioxin/furan emissions, the cost analysis does not estimate any control costs for achieving the dioxin/furan emission limits.

Carbon Monoxide and Organic HAP Control

- Organic HAP and carbon monoxide can be controlled by either improving the combustion efficiency of the unit, or installing an oxidation catalyst on the exhaust of a combustion unit. The control strategy necessary to meet the MACT floor emission limit will vary depending on the magnitude between the baseline emissions and the CO MACT floor. A step function was used to delineate what type of control strategy should be analyzed in the cost impacts analysis:
    - A boiler tune-up was estimated in the cost impacts analysis if the unit's CO baseline emissions were less than or equal to 1.5 times the applicable numeric CO

emission limit. Some commenters, including facilities and boiler and burner vendors, suggested that the concrete threshold of 400 ppm used in the CO control cost analysis in the proposal was an inappropriate cutoff for determining whether or not a tune-up could achieve the CO emission limits for certain boiler types. Many of these commenters added that significant changes in CO could not be made without a tradeoff in increased NOX emissions. Based on data in the record as well as public comment submittals, CO emissions can fluctuate widely due to operating loads and conditions. Further, most units in the database do not report dedicated combustion controls or CO oxidation catalysts installed to reduce CO emissions. Instead of using a concrete threshold of 400 ppm in final analysis, we estimated that tune-ups could achieve a percent reduction from the unit's baseline emissions. To determine an appropriate threshold level that tune-ups could achieve the limits to demonstrate annual compliance with the CO stack test in the final rule, we looked at best performing units for CO that reported paired CO CEMS emissions and boiler load data. Best performing CO units in the coal/fossil solid stoker, biomass/bio-based solid dutch oven/suspension burner and hybrid suspension grate subcategories biomass had data available. None of these units with paired CO and load data reported having any add-on dedicated CO controls or combustion controls installed on the unit. The WVDupontWashingtonWorks P05 unit reported a wide range of CO emissions at loads greater than 75 percent of its design capacity, the maximum CO value was over 9 times greater than the minimum CO value at the unit. For biomass units, the range is even more pronounced, at TXDibollTemple-Inland PB-44, the maximum CO value at loads greater than 50 percent was nearly 900 times higher than the minimum CO value, and at hybrid suspension grate burners, FLUSSugar, Boiler 8, the maximum CO value was over 1,700 times higher than the minimum CO value. Despite these large ranges, the CO stack test values of these units were all meeting the floor values during their emission stack tests. We settled on a modest threshold condition of assuming that a tune-up would meet the limit if the floor value was within 150% of the baseline emissions. Based on data provided by best performing units, it is reasonable and a conservative estimate that this level of control can be achieved without capital installations.

- If the unit's baseline CO emissions were greater than 1.5 times but less than or equal to 2.5 times the applicable numeric CO emission limit, the cost of a replacement low-NOx burner was estimated to achieve the MACT floor emission limits. Since stokers, fuel cells, or fluidized bed unit do not have replaceable burners, a linkageless boiler management system (LBMS) was the technology estimated to achieve the MACT floor when baseline CO emissions exceeded the floor in lieu of replacement low-NOx burners. A threshold of 2.5 is still less than the reported findings from best performing boilers in the coal and biomass subcategories that demonstrate wide fluctuations in CO emissions without any added CO controls, as discussed above. However, since we do not have similar data available for the liquid and process gas subcategories, we opted to select a conservatively low threshold to address some concerns received from public comments about underestimating the costs of CO control.
- Finally, if the baseline CO emissions were greater than 2.5 times the applicable CO emission limit, the cost impacts analysis estimated that a CO oxidation catalyst would be required to meet MACT floor limits.

Work Practice Costs

- All small boilers (less than 10 mmBtu per hour), limited use boilers (less than 876 hours of operation per year), are required to conduct a biennial boiler tune-up. All large boilers burning natural gas, refinery gas, or other on-spec gaseous fuels are required to conduct an annual tune-up. The cost to conduct an annual tune-up is based on the cost estimate provided in a report by the Industrial Extension Service[16]. This report indicated that the initial set-up for boiler tune-up was \$3,000 to \$7,000 per boiler; thereafter, annual tuning costs \$1,000 per boiler. An average of \$5,000 per boiler initial set-up costs was annualized over 5 years at a 7 percent rate, and added to the subsequent year tune-up costs. The resultant annualized cost for an annual tune-up is \$2,875 per boiler, as shown in Equation 1.

$$\text{Annual Tune-up Cost (\$2008)} = \{[C_{\$2004} * (X_{2008} / X_{2004}) * i * (1+i)^y] / [(1+i)^y - 1)]\} + [Z_{\$2004} * (X_{2008} / X_{2004})] = \$2,875 \quad \textbf{(Equation 1)}$$

Where:

$C_{\$2004}$ = Average set-up cost, \$5,000 (from 2004)

X_{2008} = 2008 cost index, 575.4
X_{2004} = 2004 cost index, 442.2
i = interest rate, 7%
y = length of annuity, 5 years
$Z_{\$2004}$ = annual tuning cost, $1,000 (from 2004)

Biennial tune-up costs would provide some cost savings, although the costs of the initial tune-up set-up must be factored into both of the work practice frequencies, so this analysis used a single tune-up cost, which is based on an annual frequency. The annualized cost for a biennial tune-up is $2,228 per boiler, as shown in Equation 2.

$$\text{Biennial Tune-up Cost (\$2008)} = \{[C_{\$2004} * (X_{2008}/X_{2004}) * i * (1+i)^y] / [(1+i)^y - 1)]\} + [(Z_{\$2004} / 2) * (X_{2008}/X_{2004})] = \$2{,}228 \quad \textbf{(Equation 2)}$$

Where:
$C_{\$2004}$ = Average set-up cost, $5,000 (from 2004)
X_{2008} = 2008 cost index, 575.4
X_{2004} = 2004 cost index, 442.2
i = interest rate, 7%
y = length of annuity, 5 years
$Z_{\$2004}$ = annual tuning cost, $1,000 (from 2004)

A total of 12,266 boilers and process heaters meet one of the above criteria and are subject to a tune-up work practice in lieu of add-on controls.

- All facilities are expected to conduct a one-time energy audit. An annual cost of $854 per audit was used for commercial facilities and $18,292 per audit was used for industrial facilities, and these costs are the same as the estimates included in the proposal. Although some commenters indicated EPA underestimated the costs of the assessment, in the final rule EPA has reduced the scope of the assessment in the final rule to an assessment that does not exceed one to three days in length for units consuming less than 1 trillion Btu/year of energy. For larger units, the audit is reduced in scope to assess for at least 20 percent of the energy output of the boiler system. As discussed in the memorandum for Estimating Control Costs from Major Source Boilers and Process Heaters, the cost of an energy audit ranges from $75,000 for industrial-scale energy audits to between $2,000 and $5,000 per energy audit for institutional and commercial-scale audits.[2] This larget estimate is based on costs presented to the 2009 Boiler Small Business Regulatory Flexibility Act panel by an affected small entity, Port Townsend Paper Company. The cost of each type of audit was annualized over 5 years at 7 percent to obtain an annualized cost estimate. For the cost impacts analysis, 1,639 facilities are expected to conduct an audit, 197 facilities are commercial or institutional and 1,442 facilities are industrial.

Testing and Monitoring Cost Impacts

Testing and monitoring requirements varied depending on the equipment installed on the unit to control emissions, the design capacity of the unit, and the fuel category the unit was assigned to.

Testing Costs

All boilers and process heaters designed to burn solid and gaseous fuels were expected to conduct an annual compliance test for PM, HCl, Hg, D/F, and CO. The cost to conduct stack tests for these five pollutants was estimated to be $44,000 per year for boilers combusting solid or other gaseous fuels. Based on comments received about testing under worst-case conditions, many solid fuel boilers which fire multiple fuel streams or types of fuel are expected to conduct repeated testing for mercury and HCl at a cost of $18,000 per year.

Boilers and process heaters designed to burn liquid fuels were expected to conduct an annual compliance test for PM, D/F, and CO. In lieu of a stack test boilers designed to burn liquid fuels were expected to conduct fuel analysis, or report fuel analyses received from a fuel supplier for chlorine and Hg. Conducting stack tests for PM, D/F, and CO and fuel analysis for chlorine and Hg was estimated to be $16,000 per year. Although other fuels are eligible to comply with the promulgated rule through fuel analysis in lieu of stack testing, this cost estimate conservatively assumed that only units designed to fire liquid fuels would use this compliance alternative. The methods and data sources used to estimate testing and monitoring costs are discussed in other memoranda.[2]

The final rule includes a provision for gaseous fuels other than natural gas and refinery gas to demonstrate that they meet the specifications outlined in the rule for mercury and hydrogen sulfide. We reviewed the database for facilities that had boilers with heat input capacities of at least 10 mmBtu/hr that are firing gaseous fuels other than natural gas or refinery gas, and we estimated that these 45 facilities would need to conduct monthly fuel analysis, at a cost of $600 per month, or $7200 per year. The methods and costs associated with demonstrating that the gas meets the specifications for mercury and hydrogen sulfide are discussed in another memorandum.[4] Because the fuel spec can be conducted upstream of the combustion equipment, EPA determined that one specification per month, per facility, would be the likely compliance mechanism for units opting to demonstrate that their gaseous fuels meet the specification.

Small boilers often exhaust to small diameter stacks that do not have any test ports or test platforms installed. Similarly, based on the public comments received limited use units often do not have test ports or test platforms installed. For these units, we estimated the additional costs to these costs to construct or rent scaffolding and install test ports. The costs include installation of 4 test ports, 90 degrees opposed to each other, and five weeks rental of temporary scaffolding. EPA estimates that these small sources would incur an additional $196 million to install test ports and rent temporary scaffolding. Many establishments in each industry, commercial, or institutional sector are associated with multiple (as many as a 700) small units. A summary of the costs by fuel category is shown in Table 3-1 below.

Table 3-1: Cost Estimate for Renting Scaffolding and Constructing Test Ports at Limited Use and Small Boilers and Process Heaters

Fuel Category	Number of Limited Use and Small Boilers and Process Heaters	Port Costs ($2008)	Renting Temporary Scaffolding ($2008)	Total Costs ($2008)
Coal	15	164,722	210,000	374,722
Biomass	21	230,610	294,000	524,610
Gas 1	7433	81,624,999	104,062,000	185,686,999
Gas 2	51	560,053	714,000	1,274,053
Liquid	358	3,931,353	5,012,000	8,943,353
Total	7,878	86,511,737	110,292,000	196,803,737

Monitoring Costs

Various monitor configurations were installed based on the size of the unit and the pollution control devices expected to be installed to achieve the MACT floor emission limits. For units expected to install packed bed wet scrubbers, an annualized cost of $5,600 for a scrubber parametric monitor was included in the cost analysis. If a unit was expected to install DIFF, the cost to monitor sorbent injection rate and add a bag leak detection monitor was included in the analysis, based on the unit's hours of operation. For units expected to install a fabric filter, an annualized cost of $9,700 for a bag leak detection monitor was included in the cost analysis. If a unit was expected to install ACI, the cost to monitor the carbon injection rate was included in the analysis, based on the unit's hours of operation. For units that did not install a PM CEMS and did not install a scrubber to meet HCl limits, an annualized cost of $14,660 for an opacity monitor was included in the cost analysis. While the final rule includes a cutoff of greater than 250 mmBtu/hr, in order to be consistent with the thresholds in the boiler NSPS (40 CFR 60, Subparts Db and Dc) the cost analysis includes the cost of a PM CEMS for units with a heat input capacity of 250 mmBtu/hr or more. Oxygen monitors were required for all boilers and process heaters subject to CO emission limits, these monitors were assumed to be extractive type monitors with an annualized cost of $1,436. Although several units are expected to have O2 monitors installed on the units for other reasons, such as to monitor combustion efficiency, since the number of units with monitors installed and calibrated according to EPA performance specifications is unknown, this analysis applies the cost of an O2 monitor to all units subject to a CO emission limit. No PM CEMS or opacity monitors were assumed for boilers and process heaters designed to gaseous fuels.

Fuel Savings Impacts

This cost analysis includes an estimate of energy savings of one percent for every unit that is expected to install controls to improve combustion, or conduct an annual tune-up or energy audit. Further, documents from the Sustainable Energy Authority of Ireland have charted efficiency gains as a function of boiler fuel type and time elapsed since the previous tune-up.[8] Many best practices are considered pollution prevention because they reduce the amount of fuel combusted which results in a corresponding reduction in emissions from the fuel combustion. Further boiler tune-ups have been shown to improve the efficiency of a boiler between 1 and 5 percent, depending on the age of the unit and the time lapse since the previous tune-up[10-15, 17-19]. Other combustion controls such as upgrading burners and installation of an LBMS are also expected to improve the efficiency of the unit, thus reducing fuel consumption. This cost analysis assumes an annual fuel savings of 1 percent. The energy savings is estimated using the Equation 3:

Annual Fuel Savings (mmBtu/yr) = DC * CF * Op_{hours}* EG **(Equation 3)**
Where:
DC = unit design capacity (mmBtu/hr)
CF = capacity factor, 90% of design capacity
Op_{hours} = annual operating hours reported in 2008 survey (hours/year)
EG = Efficiency gain, estimated to be 1%

After the fuel savings for each boiler and process heater was calculated, the both industrial and commercial prices for coal, #2 distillate fuel oil, #6 residual fuel oil, and natural gas were obtain from the EIA.[5] The EIA data reported fuel prices as $/ton for coal, $/thousand cubic feet for natural gas, and cents per gallon for fuel oil. The higher heating values were obtained from Table C-1 of the EPA Mandatory Reporting Rule (40 CFR part 98 subpart C) and the higher heating values were used to convert the fuel prices to a standard unit of measure, $ per mmBtu. Using the NAICS code reported by each facility and the fuel category assigned to each combustion unit, the appropriate fuel price was multiplied by the calculated fuel savings. Table 3-2 below shows the distribution of reported NAICS codes considered as industrial versus commercial in terms of fuel pricing.

Table 3-2: Summary of NAICS Code Distribution by Sector

Sector	NAICS Codes
Industrial	221, 311, 312, 313, 314, 316, 321, 322, 323, 324, 325, 326, 327, 331, 332, 333, 334, 335, 336, 337, & 339
Commercial	111, 113, 115, 211, 212, 423, 424, 441, 481, 482, 486, 488, 493, 531, 541, 561, 562, 611, 622, 623, 811, 921, & 928

This cost analysis only estimates the fuel savings from units in the coal, liquid and natural gas and other gaseous fuel categories. A fuel savings was not estimated for units in the biomass fuel category since the price of biomass fuels is variable, and often biomass is an on-site industrial byproduct instead of a purchased fuel. The logic behind the costs analysis for new units were identical to that of existing units for the recommended option with the exception of the energy audit. Energy audits are a recommended beyond-the-floor option for existing units only and therefore no costs for an audit were included in the new source floor analysis.

3.2 Alternative Option

The alternative option includes control device and testing/monitoring cost estimation logic identical to the Recommended Option outlined above, except that units combusting biomass and coal must meet separate numeric emission limitations for Hg, PM, and HCl. All other aspects of the options are identical. As a result of this modified option and its computed MACT floors, the number of solid fuel units estimated to install controls to meet the limits were adjusted as follows:

- A new fabric filter was estimated to be installed at 451 existing boilers and process heaters to control Hg emissions. This does not include the fabric filters installed in combination with dry injection to achieve HCl control. A new fabric filter is required to be installed on 3 fewer boilers and process heaters under this option when compared to the recommended option.
- Incremental ACI equipment was estimated to be installed at 11 existing boilers and process heaters for the controlling Hg. Incremental ACI equipment is required to be installed on 97 fewer boilers and process heaters compared to the recommended option.
- ESP technology was estimated to be installed at 34 existing boilers and process heaters to control PM. ESP technology is required to be installed on an additional 24 boilers and process heaters under this option when compared to the recommended option.
- Wet scrubbers were estimated to be necessary to control HCl emissions at 774 existing boilers and process heaters. This is identical to the number of sources estimated to install a scrubber for HCl control under the recommended option.
- DIFF was identified to be necessary to control HCl emissions at 390 existing boilers and process heaters. DIFF is estimated to be installed on an additional 254 boilers and process heaters under this option when compared to the recommended option.
- Incremental sorbent injection was identified to be necessary to control HCl emissions at 23 existing boilers and process heaters. Incremental sorbent injection is estimated to be installed on an additional 16 boilers and process heaters under this option compared to the recommended option.

3.3 New Unit Options

The recommended option for new units follows the same logic for estimating control costs as the recommended option for existing units outlined above with one exception. For boilers with a rated heat capacity less than 500,000 Btu per hour, a tune-up cost of $200 was selected. This value was based on research of tune-up costs for similarly sized home boiler programs, which suggested the costs of a tune-up ranged from $60 to $150.[19,20] The alternative option for new units is also identical to the alternative option for existing units. However, no new boilers or process heaters combusting solid fuels are expected to be constructed by 2013. Since the differences in the recommended and alternative options are focused only on boilers and process heaters combusting solid fuel, there are no differences in the recommended and alternative options for new units. The new unit analysis also projects new gaseous fuels, but based on the EIA data used for the new unit projections all of these new boilers are estimated to be natural gas so no cost for a gas specification is included in the new unit analysis.

3.4 Summary of Cost Impacts

The recommended option is the promulgated option for existing and new boilers and process heaters. Tables 3-3 and 3-4 summarize the costs of the promulgated option for new and existing units. Appendix A of this memorandum provides a detailed summary of the costs according to unit size, subcategory, and individual control device costs. Appendix A also includes a summary of the costs on existing units under the alternative option considered in development of the final rule.

Table 3-3: Summary of Costs of Promulgated Options
Costs shown in $\$10^6$ (2008) with capital recovery estimated at 7%

Type of Unit	Option	Number of Units	TAC	TAC considering fuel savings	Testing & Monitoring TAC	Control TAC	Control TCI
New	Recommended	47	$6.3	$6.1	$0.3	$5.9	$20.9
Existing	Recommended	13,840	$1,804	$1,376	$135	$1,669	$5,082

Table 3-4: Summary of Total Annual Costs by Control Type for Existing Units under Recommended Option
Costs shown in $\$10^6$ (2008) with capital recovery estimated at 7%

Number of Boilers	Fabric Filter	ESP	Wet Scrubber	DIFF	Increased Caustic Rate	Combustion Controls and Oxidation Catalysts	Activated Carbon Injection	Work Practices (Tune-up)	Energy Audit
13,840	391	3.5	578	423	2.0	219	17.5	35.1	26.5

4.0 METHODOLOGY FOR ESTIMATING EMISSION REDUCTIONS

This section discusses the methodology used to estimate emission reductions from boilers and process heaters at both existing and new facilities and it presents a summary of the results for the recommended regulatory options.

4.1 Emission Reductions from Existing Boilers and Process Heaters

The emission reductions analysis for existing combustion units was done for each boiler and process heater in the major source inventory. There are a total of 13,840 boilers and process heaters at major sources that reported data in the 2008 questionnaire (ICR No. 2286.01). Each combustion unit was assigned a unit-specific or average baseline emission factor, depending on the availability of emission data reported for the unit. A detailed discussion of the procedures and results of the baseline emissions analysis is presented in another memorandum.[6]

Emission Reductions for Recommended Option

Emission reductions for PM, HCl, Hg, CO, and dioxins/furans were calculated on a ton per year basis by subtracting the baseline emissions assigned to each unit from the MACT floor emission limits corresponding to each unit's subcategory. A detailed discussion of the procedures and results of the MACT floor analysis is presented in another memorandum.[1] A percent reduction was calculated for CO. It was assumed that each combustion unit would achieve an identical percent reduction from baseline emissions for THC and VOC as was achieved for CO. A percent reduction was also calculated for HCl. It was assumed that each combustion unit would achieve an identical percent reduction from baseline emissions for HF as was achieved for HCl. A combustion unit is assumed to install a scrubber or DIFF for HCl control if it is not currently meeting the HCl floor limit, and if it doesn't already have a scrubber installed. For units required to install a scrubber or DIFF, it was assumed that the control will achieve a reduction from baseline for SO2 equivalent to the reduction in HCl. The logic for estimating SO2 reductions is a change since the proposal of the rule, to address public comments concerned with overestimating SO2 reductions. At proposal we had estimated that all units installing control for HCl removal would achieve a 95 percent reduction in SO2; by reducing the removal efficiency for SO2 to be equivalent to the reduction efficiency for HCl the revised emission reductions are more in line with the capability of the control devices estimated to be installed. A percent reduction in PM was also calculated in order to estimate total non-Hg metals reductions. It was assumed that each combustion unit would achieve an identical percent reduction from baseline emissions for each non-Hg metallic HAP as was achieved for PM. PM2.5 emissions were assumed to be a fraction of total filterable PM emissions based on fuel and control device configuration installed on the unit. The methods used to derive the contribution of PM2.5 to overall filterable PM are presented in other memoranda.[4] To calculate emission reductions for PM2.5, the emission reductions for PM were multiplied by the applicable PM2.5 fraction. Emission reductions for all pollutants for which there was no floor value were calculated on a ton per year basis.

To convert emission reductions from an emission rate on a heat input basis to an annual emission rate, Equation 4 was used:

Annual Emission Rate (tpy) = $ER_{HI} * 0.0005 * Op_{hours}$ **(Equation 4)**

Where:

ER_{HI} = emission rate (lb/mmBtu)

0.0005 = conversion factor, lbs per ton

Op_{hours} = annual operating hours reported in 2008 survey (hours/year)

To convert emission reductions from a concentration basis to an annual emission rate, Equations 5 and 6 were used:

Annual Emission Rate (tpy) = $ER_C * 0.000001 * Q_S * 60 * Op_{hours} * MW * 0.0026 * 0.0005 * (20.946 - O_2) / (20.946 - \text{Std } O_2)$ **(Equation 5)**

Where:

ER_C = emission concentration (ppm @ 3% O_2)

0.000001 = conversion factor, ppm to parts

Q_S = exhaust flowrate (dscfm)

60 = conversion factor, minutes to hours

Op_{hours} = annual operating hours reported in 2008 survey (hours/year)

MW = molecular weight of pollutant, in lb per lb-mole

0.0026 = conversion factor, lb-mole per dry standard cubic foot of gas

0.0005 = conversion factor, lb per ton

20.946 = percentage of oxygen in ambient air

O_2 = percentage of oxygen assumed in exhaust gas

Std. O_2 = 3 percent oxygen in standardized emission concentration for promulgated rule.

Annual Emission Rate (tpy) = $ER_C * 0.0283 * Q_S * 60 * Op_{hours} * 0.000000001 * 0.0022 * 0.0005 * (20.946 - O_2) / (20.946 - Std\ O_2)$ **(Equation 6)**

Where:

ER_C = emission concentration (ng/dscm @ 7% O_2)
0.0283 = conversion factor, dry standard cubic meter per dry std. cubic foot
Q_S = exhaust flowrate (dscfm)
60 = conversion factor, minutes per hour
Op_{hours} = annual operating hours reported in 2008 survey (hours/year)
0.000000001 = conversion factor, ng to g
0.0022 = conversion factor, g per lb
0.0005 = conversion factor, lb per ton
20.946 = percentage of oxygen in ambient air
O_2 = percentage of oxygen assumed in exhaust gas
Std O_2 = 7 percent oxygen in standardized emission concentration for promulgated rule.

Converting concentrations to an annual emission rate required an oxygen concentration and exhaust flowrate estimated for each specific fuel type. The development of these assumptions and estimates is presented in other memoranda.[2] All conversions required the annual operating hours for each combustion unit reported in the 2008 survey. If no operating hours were reported, the unit was assumed to operate for 8,400 hours per year (two weeks of downtime).

For units not subject to emission limitations, the emission reductions were based on a one percent gain in efficiency expected from the annual tune-up work practice standard. Efficiency gains reduce fuel use, and in turn, emissions of hazardous air pollutants. A one percent reduction in all types of emissions was estimated by multiplying the baseline emissions for each unit by a factor of 0.01.

Emission Reductions for Alternative Option

The same calculations discussed for estimating emission reductions for the recommended option were applied to all units except that boilers and process heaters combusting biomass and coal were subject to separate numeric emission limits for Hg, PM, and HCl. In these cases the adjusted MACT floors under this alternative option were subtracted from baseline emissions and then the remainder of the above calculations for the recommended option was performed.

4.2 Emission Reductions from New Boilers and Process Heaters

Based on industrial and commercial fuel consumption projections from the EIA, there are 47 new boilers and process heaters expected to come on-line by 2013.[5] a discussion of the methodology used to project new boilers and process heaters is discussed in another memorandum.[3]

The New Source Performance Standards for Industrial, Commercial and Institutional Boilers (40 CFR part 60, subparts Db, Dc) (NSPS), was reviewed to identify the expected baseline level of control for projected new units. It was determined that new boilers and process heaters larger than 30 mmBtu/hr and combusting biomass would install an ESP. This technology selection is based on the analysis used to establish the PM NSPS limit for biomass boilers. New coal units larger than 75 mmBtu/hr would have a fabric filter and wet scrubber installed, while new coal units between 30 and 75 mmBtu/hr would only have a fabric filter installed and would meet the SO_2 limits in the NSPS by using coals with low sulfur content. New units larger than 30 mmBtu/hr and combusting liquid fuel would have a fabric filter installed. All new units less than 30 mmBtu/hr would have no add-on controls and liquid fuels were expected to meet the NSPS SO_2 limits using low sulfur fuel oils. Gas-fired units of all sizes were not expected to install controls to meet any of the NSPS limits. For this impacts analysis, it was assumed that all new solid fuel units would be stokers, since stoker boilers are the most common type of solid fuel boilers and all new units would have NOx control installed as a baseline control, regardless of fuel.

After an appropriate baseline level of control was determined for each model unit, an average baseline emission factor calculated for existing units within the same fuel category and having the same level of control was assigned to each model boiler. The NSPS specifies PM and SO2 limits for new solid- and liquid-fired combustion units based on heat input. It was assumed that all new solid and liquid units would be constructed to meet these limits, so they were used as baseline emission values where applicable. The baseline emissions for each unit were subtracted from the new source MACT floor emission limit corresponding to each unit's subcategory. The same calculations discussed in Section 3.1 of this memo were used to estimate the reductions for new units.

Similar to the methods discussed in Section 4.1 of this memorandum, the emission reductions for new units were calculated by subtracting the baseline emissions assigned to each unit from the MACT floor emission limits corresponding to each unit's subcategory, except for units not subject to numeric emission limits. For units not subject to emission limitations, the emission reductions were based on a one percent gain in efficiency expected from the tune-up work practice standard. A summary of the estimated emission reductions at existing units for both the recommended and alternative options are located in Appendix B-1.

5.0 METHODOLOGY FOR ESTIMATING SECONDARY IMPACTS

Secondary impacts include the solid waste, water, wastewater, electricity required to operate air pollution control devices and the resultant greenhouse gas emissions, as well as the additional energy savings resulting from improved combustion controls or work practices required by the NESHAP. This section documents the inputs and equations used to estimate these secondary impacts, and it summarizes the impacts at existing units under promulgated regulatory option 4 and new units under promulgated regulatory option 1. Table 5-1 summarizes the cost, emission, and secondary impacts of this promulgated NESHAP. Appendices C-1 and C-2 present a detailed breakdown of the secondary waste, water, and energy impacts from each subcategory of new and existing boilers and process heaters, respectively.

Table 5-1: Summary of Secondary Impacts

Impact	New Units (recommended option)	Existing Units (recommended option)
Water (gal/yr)	242,000	671 million
Wastewater (gal/yr)	193,900	266 million
Solid Waste (tons/yr)	580	100,500
Purchased Electricity (kW-hr/yr)	6.2 million	1.4 billion
CO2 Emissions from Purchased Electricity (tons/yr)	4,100	910,000
Energy Savings* (trillion Btu/yr)	0.01	44.5

* Energy savings is calculated for units in the coal, liquid and gas subcategories.

The secondary impacts were calculated using algorithms and assumptions described in another memorandum.[2] These algorithms and assumptions were applied to the existing boiler and process heaters, where the baseline emissions for each unit exceeded the promulgated MACT floor emission limit except for small units (less than 10 mmBtu/hr), limited use units, and units firing natural gas, refinery gas, or other on-spec gaseous fuels. A one percent energy savings was calculated for all units, including the small, limited use and gas-fired units since these units are expected to conduct a tune-up. For new units, the algorithms and assumptions were applied to model units representing units expected to come online between 2010 and 2013, when the baseline emissions for each model exceeded the promulgated MACT floor emission limit for new units except for small units and units firing natural gas, refinery gas, or other on-spec gaseous fuels. Similar to existing units these small and gas-fired units are not required to meet a numerical emission limit, and therefore not expected to incur any secondary waste, water, or electricity impacts from these controls. A one percent energy savings from small units and units burning natural gas, refinery gas, or other on-spec gaseous fuels are included in the energy savings estimate in Table 5-1 since these units are expected to conduct a tune-up. The methodology used to assign baseline emission factors to new and existing units are discussed in another memorandum.[6]

5.1 Wastewater and Water Impacts

The water required to create a slurry in the packed scrubber and the wastewater generated by the effluent of a packed bed scrubber were calculated for every unit expected to install a scrubber to meet the HCl limits in the promulgated rule. Both the water and wastewater calculations required the use of several constants and variables. The constants including the density of gas, moles of salt needed per mole of hydrogen chloride in the exhaust gas, the molecular weight of the salt used, the fraction of the waste stream treated, operating hours per year and the molecular weight of the gas. The data sources for these constants are provided in another memorandum.[2] The variables used to estimate the quantity of water required and wastewater generated were calculated based on characteristics reported for each existing unit in the 2008 survey and for the characteristics assigned to each new model unit. The variables included: exhaust flow rate from the combustion unit to the control device in actual cubic feet per minute, the inlet loading of hydrogen chloride to the control device (mole fraction), and the efficiency of the control device in removing hydrogen chloride from the exhaust gas (percent reduction). The calculations used to estimate each variable are provided in another memorandum.[2] The total national water and wastewater amounts in Table 5-1 were determined by adding the per unit water and wastewater estimates for all new and existing units, respectively.

5.2 Solid Waste Impacts

Solid waste is generated from collecting dust and fly ash in fabric filters or ESP control devices, spent carbon associated with ACI, or spent caustic from increasing the caustic injection rate. Solid waste impacts were estimated for every unit expected to install a fabric filter for mercury control or a DIFF for HCl control, ACI for mercury emission limits, or install an ESP to meet PM emission limits. The total national solid waste amounts in Table 5-1 were determined by adding the per unit solid waste estimates for all new and existing units, respectively. To estimate the solid waste contribution from each of these control devices, the variables were calculated based on characteristics reported for each existing unit in the 2008 survey and for the characteristics assigned to each new model unit. The calculations used to estimate each variable and the quantity of solid waste generated are provided in another memorandum.[2]

The solid waste (dust, fly ash) generated by the use of an electrostatic precipitator was calculated when an electrostatic precipitator was determined to be necessary to meet the NESHAP emission limits for PM. Estimates of the solid waste collected in an ESP was based on several variables including: exhaust flow rate from the combustion unit to the control device (acfm); the inlet loading of particulate matter to the control device (gr/acfm); operating hours (hr/year) and the efficiency of the control device required to meet the PM emission limits in the promulgated NESHAP.

The solid waste generated from the collection of dust and fly ash in a fabric filter was calculated when a fabric filter was determined to be necessary to meet the promulgated NESHAP emission limits for particulate matter and/or mercury. The calculation required the use of three variables, including: exhaust flow rate from the combustion unit to the control device (dscfm); operating hours (hr/year) and the inlet loading of particulate matter to the control device (gr/acfm).

For this analysis, the spent carbon collected from units with ACI is assumed to be disposed of instead of being re-generated. The amount of spent carbon created from ACI was calculated when ACI was expected to be necessary to meet the promulgated NESHAP emission limits for mercury or dioxin/furan. The calculation required the use of six variables, including: exhaust flow rate from the combustion unit to the control device (dscfm); operating hours (hr/year), required removal efficiency for mercury and dioxin/furan, and an adjustment factor based required removal efficiency of mercury or dioxin /furan.

The solid waste generated by the use of increased caustic was calculated for those units where additional caustic was expected to achieve the promulgated NESHAP emission limits for HCl. The calculation required the use of three variables, including: exhaust flow rate from the combustion unit to the control device (dscfm); operating hours (hr/year), and the required removal efficiency for HCl.

5.3 Electricity Impacts

The amount of electricity required to operate a control device was calculated for a packed scrubber, electrostatic precipitator, fabric filter, DIFF, CO oxidation catalyst and the fans for the ductwork associated with this equipment. These impacts were assessed for every unit that was estimated to require hydrogen chloride and/or particulate matter control. Electricity requirements are one output of the cost algorithms used in the analyses, so no additional calculations were necessary. For some units, an electrical demand from multiple control devices was estimated. The total national electricity demand in Table 5-1 was determined by adding the per unit solid waste estimates for all new and existing units, respectively. To estimate the electricity demand from each of these control devices, a set of variables were calculated based on characteristics reported for each existing unit in the 2008 survey and for the characteristics assigned to each new model unit. The constants, variables, and calculations used to estimate each variable and the electricity demand to operate the control devices are provided in another memorandum.[2]

5.4 Greenhouse Gas Emissions from Electricity Usage

Since greenhouse gases are generated from electricity production, an estimate of carbon dioxide emissions was generated for the electricity impacts of the add-on air pollution control devices. The total electricity usage from all control devices was multiplied by the national average carbon dioxide emission factor for carbon dioxide emissions from EPA's 2005 e-GRID to obtain the expected annual carbon dioxide emissions.[9] No carbon dioxide emissions were estimated for boilers or process heaters conducting a boiler tune-up since no electricity impacts were estimated for those units.

5.5 Energy Savings Impacts

The energy savings from combustion controls such as low NOx burners or linkageless boiler management systems, and work practice standards, including a tune-up, and implementing the energy audit findings with a short-term payback can improvements in efficiency, thereby reducing fuel consumption. This secondary impacts analysis only estimates a one percent efficiency gain from tune-up work practices and installation of combustion controls to be conservative and consistent with the assumptions made in Section 3.1 of this memorandum. No energy savings are attributed to the energy assessment in this analysis. Quantifying the exact gains in efficiency from each of these work practice standards is difficult, and may depend on the baseline operating efficiency of each unit.

Section 3.1 discusses the fuel savings impacts in terms of annualized cost savings to each boiler or process heater, and the national energy savings presented in Table 4.1 of this section follows the same methodology as was discussed in Section 3.1 and reflect the savings from boilers in the coal, gas, and liquid fuel categories only.

5.6 Estimating Secondary Impacts for Existing and New Units

Appendices C-1 and C-2 present a detailed breakdown of the secondary waste, water, and energy impacts from each subcategory of new and existing boilers and process heaters, respectively. The differences presented between the recommended and alternative regulatory options are based on the number of controls estimated to be installed to meet the floor limits associated with each option, which in turn affects the amount of waste, wastewater, water, and energy consumed by the control devices installed for PM, HCl, and Hg.

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FPL Industrial Boiler MACT Equipment / Estimated Compliance Costs

Facility	Equipment Type	Location HAP Status	MACT Rule	Rated Heat Input (MMBtu/hr)	Fuel Type 1	Fuel Type 2	Existing / New ?	Test Port?	Biennial Tune-Up?	Stack/Fuel Testing ?	Potential Emission Limits?	Energy Assessment?	Biennial Tune-Up[1]	Test Port Installation[2]	Fuel/Stack Testing[3]	Energy Assessment[4]
Canaveral	Manatee Heater	Major	DDDDD	30	Natural Gas	N/A	New	Unk	Yes	No	No	Yes	$ -	$ -	$ -	$ 18,292
Lauderdale	Auxilliary Boiler	Major	DDDDD	15.5	Propane	N/A	Existing	No	Yes	No	No	Yes	$ 2,875	$ 10,143	$ -	$ 18,292
Ft. Myers Plant	Process Heater (3A)	Major	DDDDD	10	Natural Gas	N/A	Existing	Yes	Yes	No	No	Yes	$ 2,875	$ 10,143	$ -	
Ft. Myers Plant	Process Heater (3B)	Major	DDDDD	10	Natural Gas	N/A	Existing	Yes	Yes	No	No	Yes			$ -	$ 75,000
Martin	Auxilliary Boiler (3&4)	Major	DDDDD	16.3	Natural Gas	N/A	Existing	No	Yes	No	No	Yes	$ 2,875	$ 10,143	$ -	$ 75,000
Putnam	Auxilliary Boiler	Major	DDDDD	16.3	Natural Gas	#2 Fuel Oil	Existing	No	Yes	Yes	Yes	Yes	$ 2,875	$ 10,143	$ 26,000	$ 18,292
West County Energy Center	Auxilliary Boiler	Major	DDDDD	98	Natural Gas	N/A	New	Yes	Yes	No	No	Yes	$ 2,875		$ -	$ 18,292
West County Energy Center	Process Heater (1)	Major	DDDDD	8.3	Natural Gas	N/A	New	No	Yes	No	No	Yes	$ 2,875	$ 10,143	$ -	
West County Energy Center	Process Heater (2)	Major	DDDDD	8.3	Natural Gas	N/A	New	No	Yes	No	No	Yes	$ 2,875	$ 10,143	$ -	
West County Energy Center	Process Heater (3)	Major	DDDDD	8.3	Natural Gas	N/A	New	No	Yes	No	No	Yes	$ 2,875	$ 10,143	$ -	
West County Energy Center	Process Heater (4)	Major	DDDDD	8.3	Natural Gas	N/A	New	No	Yes	No	No	Yes	$ 2,875	$ 10,143	$ -	
													$ 25,875	$ 81,144	$ 26,000	$ 223,168
Manatee Terminal	Process Heater (A)	Minor (Area)	JJJJJ	14.5	#2 Fuel Oil	N/A	Existing	Yes	No	No	No	No			$ -	
Manatee Terminal	Process Heater (B)	Minor (Area)	JJJJJ	12.5	Natural Gas	#2 Fuel Oil	New	Yes	No	No	No	No			$ -	
Martin Terminal	Auxilliary Boiler (A)	Minor (Area)	JJJJJ	12.5	#2 Fuel Oil	#6 Fuel Oil	Existing	No	Yes	No	No	Yes	$ 2,875	$ 10,143	$ -	$ 18,292
Martin Terminal	Auxilliary Boiler (B)	Minor (Area)	JJJJJ	12.5	#2 Fuel Oil	#6 Fuel Oil	Existing	No	Yes	No	No	Yes		$ 10,143	$ -	
													$ 2,875	$ 20,286	$ -	$ 18,292
													$ 28,750	$ 101,430	$ 26,000	$ 241,460
															Grand Total	$ 397,640

Notes: 1) EPA estimated annualized cost for Biennial Tune-Up = $2,875
2) Test port installation average projected cost of $10,143 per stack
3) Stack testing cost based on EPA estimate reduced for fewer analytical parameters (3/5)
4) EPA Energy Assessment for FPL sites with complex emission units/configuration assumes EPA estimate of $75 k and average cost using EPA estimate of $18,292 for sites with fewer process units.