Comprehensive Exhibit List for Entry into Hearing Record

Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Entered
Staff				
1		Exhibit List - 1	Comprehensive Exhibit List	
2		Staff's Composite Exhibit – 2	**Florida Power & Light** **Interrogatories** 1. FPL's Response to Staff's 1st Set of Interrogatories (Nos. 1-36) *[Bates Nos. 00000001-00000076]* 2. FPL's Response to Staff's 2nd Set of Interrogatories (Nos. 37-38) *[Bates Nos. 00000077-00000083]* 3. FPL's Response to Staff's 3rd Set of Interrogatories (Nos. 39-46) *[Bates Nos. 00000084-00000102]* 4. FPL's Response to Staff's 4th Set of Interrogatories (No. 47) *[Bates Nos. 00000103-00000104]* 5. FPL's Response to Staff's 5th Set of Interrogatories (Nos. 48-50) *[Bates Nos. 00000105-00000119]* 6. FPL's Response to Staff's 6th Set of Interrogatories (No. 51) *[Bates Nos. 00000120-00000123]* 7. FPL's Response to Staff's 7th Set of Interrogatories (No. 52) *[Bates Nos. 00000124-00000145]* 8. FPL's Response to Staff's 8th Set of Interrogatories (Nos. 53-56) *[Bates Nos. 00000146-00000182]*	

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI **EXHIBIT** 1
PARTY FLORIDA PUBLIC SERVICE COMMISSION STAFF
DESCRIPTION COMPREHENSIVE EXHIBIT LIST
DATE 11/01/11

Comprehensive Exhibit List for Entry into Hearing Record

Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Entered
			9. FPL's Response to Staff's 9th Set of Interrogatories (Nos. 57-60) *[Bates Nos. 00000183-00000194]*	
			10. FPL's Response to Staff's 10th Set of Interrogatories (Nos. 61-67) *[Bates Nos. 00000195-000000287]*	
			11. FPL's Response to Staff's 11th Set of Interrogatories (Nos. 68-71) *[Bates Nos. 000000288-00000298]*	
			12. FPL's Response to Staff's 12th Set of Interrogatories (No. 72) *[Bates Nos. 000000299-00000301]*	
			Progress Energy Florida	
			Interrogatories	
			13. PEF's Response to Staff's 1st Set of Interrogatories (Nos. 1-7) *[Bates Nos. 00000302-00000314]*	
			14. PEF's Response to Staff's 2nd Set of Interrogatories (No. 8) *[Bates Nos. 00000315-00000318]*	
			15. PEF's Response to Staff's 3rd Set of Interrogatories (No. 9) *[Bates Nos. 00000319-00000323]*	
			16. PEF's Response to Staff's 4th Set of Interrogatories (Nos. 10-11) *[Bates Nos. 00000324-00000330]*	
			17. PEF's Response to Staff's 5th Set of Interrogatories (No. 12) *[Bates Nos. 00000331-00000335]*	

Comprehensive Exhibit List for Entry into Hearing Record

Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Entered
			18. PEF's Response to Staff's 6th Set of Interrogatories (Nos. 13-14) *[Bates Nos. 00000336-00000360]* 19. PEF's Response to Staff's 7th Set of Interrogatories (Nos. 15-16) *[Bates Nos. 00000361-00000367]* 20 PEF's Response to Staff's 8th Set of Interrogatories (No. 17) *[Bates Nos. 00000368-00000375]* 21 PEF's Response to Staff's 9th Set of Interrogatories (Nos. 18-19) *[Bates Nos. 00000376-00000387]* 22 PEF's Response to Staff's 10th Set of Interrogatories (No. 20) *[Bates Nos. 00000388-00000391]* **Tampa Electric Company** **Interrogatories** 23. TECO's Response to Staff's 1st Set of Interrogatories (Nos. 1-9) *[Bates Nos. 00000392-00000418]* 24. TECO's Response to Staff's 2nd Set of Interrogatories (Nos. 10-11) *[Bates Nos. 00000419-00000424]* 25. TECO's Response to Staff's 3rd Set of Interrogatories (Nos. 12-14) *[Bates Nos. 00000425-00000432]*	

Comprehensive Exhibit List for Entry into Hearing Record

Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Entered
			Production of Documents	
			26. TECO's Response to Staff's 1st Production of Documents (1-2) *[Bates Nos. 00000433-00000464]*	
			Gulf Power Company	
			Interrogatories	
			27. Gulf's Response to Staff's 1st Set of Interrogatories (No. 1) *[Bates Nos. 00000465-00000466]*	
			28. Gulf's Response to Staff's 2nd Set of Interrogatories (Nos. 2-3) *[Bates Nos. 00000467-00000472]*	
			29. Gulf's Response to Staff's 3rd Set of Interrogatories (No. 4) *[Bates Nos. 00000473-00000476]*	
			30. Gulf's Response to Staff's 4th Set of Interrogatories (Nos. 5-7) *[Bates Nos. 00000477-00000482]*	
			31. Gulf's Response to Staff's 5th Set of Interrogatories (Nos. 8-12) *[Bates Nos. 00000483-00000493]*	
			32. Gulf's Response to Staff's 6th Set of Interrogatories (Nos. 13-15) *[Bates Nos. 00000494-0000507]*	
			33. Gulf's Response to Staff's 7th Set of Interrogatories (Nos. 16-30) *[Bates Nos. 00000508-00000528]*	

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
			Additional Materials 34. Gulf Power ECRC Projections for January 2012-December 2012 without turbine upgrades. See Exhibit RWD-3 *[Bates Nos. 00000529-00000533]*	
Exhibits preceded by an asterisk have been stipulated for admission into the record. ***Florida Power & Light Company (Direct)***				
*3	T. J. Keith	TJK-1 (Revised)	Appendix - Environmental Cost Recovery Final True-up January 2010-December 2010 Commission Forms 42 - 1A through 42 - 9A	
*4	T. J. Keith	TJK-2 (Revised)	Appendix - Environmental Cost Recovery - Estimated/Actual Period January 2011-December 2011 Commission Forms 42-1E through 42-9E	
*5	T. J. Keith	TJK-3	Appendix I - Environmental Cost Recovery Projections January 2012-December 2012 - Commission Forms 42-1P through 42-8P	
*6	R. R. Labauve	RRL-1	Florida Department of Environmental Protection Industrial Wastewater Facility Permit No. FL0002208 for St. Lucie Power Plant	
*7	R. R. Labauve	RRL-2	Florida Department of Environmental Protection Administrative Order No AO022TL for St. Lucie Power Plant	
*8	R. R. Labauve	RRL-3	FPL Supplemental CAIR/CAMR/CAVR Filing	

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
*9	R. R. Labauve	RRL-4	Changes and Anticipated Changes in WET testing for FPL Facilities	
*10	R. R. Labauve	RRL-5	NPES Permit No. FL0001538- Port Everglades Plant	
*11	R. R. Labauve	RRL-6	Pertinent Excerpts from Final Industrial Boiler MACT Rule for Area Sources 40-CFR Part 63 Subpart DDDDD	
*12	R. R. Labauve	RRL-7	Pertinent Excerpts from Final Industrial Boiler MACT Rule for Area Sources 40-CFR Part 63 Subpart JJJJJ	
*13	R. R. Labauve	RRL-8	EPA Delay of Subpart DDDDD	
*14	R. R. Labauve	RRL-9	ERG Memorandum	
*15	R. R. Labauve	RRL-10	FPL IBM ACT Cost Matrix	
Exhibits preceded by an asterisk have been stipulated for admission into the record. ***Progress Energy Florida, Inc.***				
16	Will Garrett	WG-1	PSC Forms 42-1A thru 42-8A - January 2010 – December 2010	
17	Will Garrett	WG-2	Capital Program Detail January 2010 – December 2010	
18	Patricia Q. West	PQW-1	Review of Integrated Clean Air Compliance Plan	

Comprehensive Exhibit List for Entry into Hearing Record				
Hearing I.D. #	**Witness**	**I.D. # As Filed**	**Exhibit Description**	**Entered**
19	Patricia Q. West	PQW-2 **(Confidential)**	Verified Petition for Approval of Cost Recovery for New Enviromental Program and associated Exhibits filed on March 11, 2011	
20	Patricia Q. West	PQW-3	Verified Petition to Modify Scope of Existing Enviromental Progam and associated exhibits files on March 11, 2011	
21	Patricia Q West	TGF-3	Form 42-5P, pages 3 of 18, 4 of 18, 6 of 18, 8 of 18, 10 of 18, 11 of 18, 12 of 18, 13 of 18, 14 of 18, 15 of 18, 16 of 18, 17 of 18, and 18 of 18	
*22	Cory Zeigler	TGF-3	Form 42-5P, Pages 1 of 18, 2 of 18, and 9 of 18	
*23	Kevin Murray	KM-1	Crystal River Project Organizational Structure	
*24	David Sorrick	DS-1	Crystal River Project Organizational Structure	
*25	David Sorrick	TGF-3	Form 42-5P, Page 7 of 16	
26	Thomas G. Foster	TGF-1	PSC Forms 42-1E through 42-9E January 2011 – December 2011	
27	Thomas G. Foster	TGF-2	Capital Program Detail January 2011 – December 2011	
28	Thomas G. Foster	TGF-3 (Revised)	PSC Forms 42-IP through 42-8P January 2012 – December 2012	
29	Thomas G. Foster	TGF-4	Capital Program Detail January 2012 – December 2012	

Comprehensive Exhibit List for Entry into Hearing Record

Hearing I.D. #	Witness	I.D. # As Filed	Exhibit Description	Entered
30	Thomas G. Foster	TGF-5	Commission Form 42-8E, Page 15 Revised	
Exhibits preceded by an asterisk have been stipulated for admission into the record. ***Tampa Electric Company (Direct)***				
*31	Howard T. Bryant	HTB-1	Final Environmental Cost Recovery Commission Forms 42-1A through 42-8A for the period January 2010 through December 2010	
*32	Howard T. Bryant	HTB-2	Environmental Cost Recovery Commission Forms 42-1E through 42-9E for the Period January 2011 through December 2011	
*33	Howard T. Bryant	HTB-3	Forms 42-1P through 42-8P Forms for January 2012 through December 2012	
Exhibits preceded by an asterisk have been stipulated for admission into the record. ***Gulf Power Company (Direct)***				
34	J.O. Vick	JOV-1	Plant Crist NPDES Permit	
*35	R. W. Dodd	RWD-1	Calculation of Final True-up 1/10 – 12/10	
*36	R. W. Dodd	RWD-2	Calculation of Estimated True-up 1/11 – 12/11	
*37	R. W. Dodd	RWD-3	Calculation of Projection 1/12 - 12/12	

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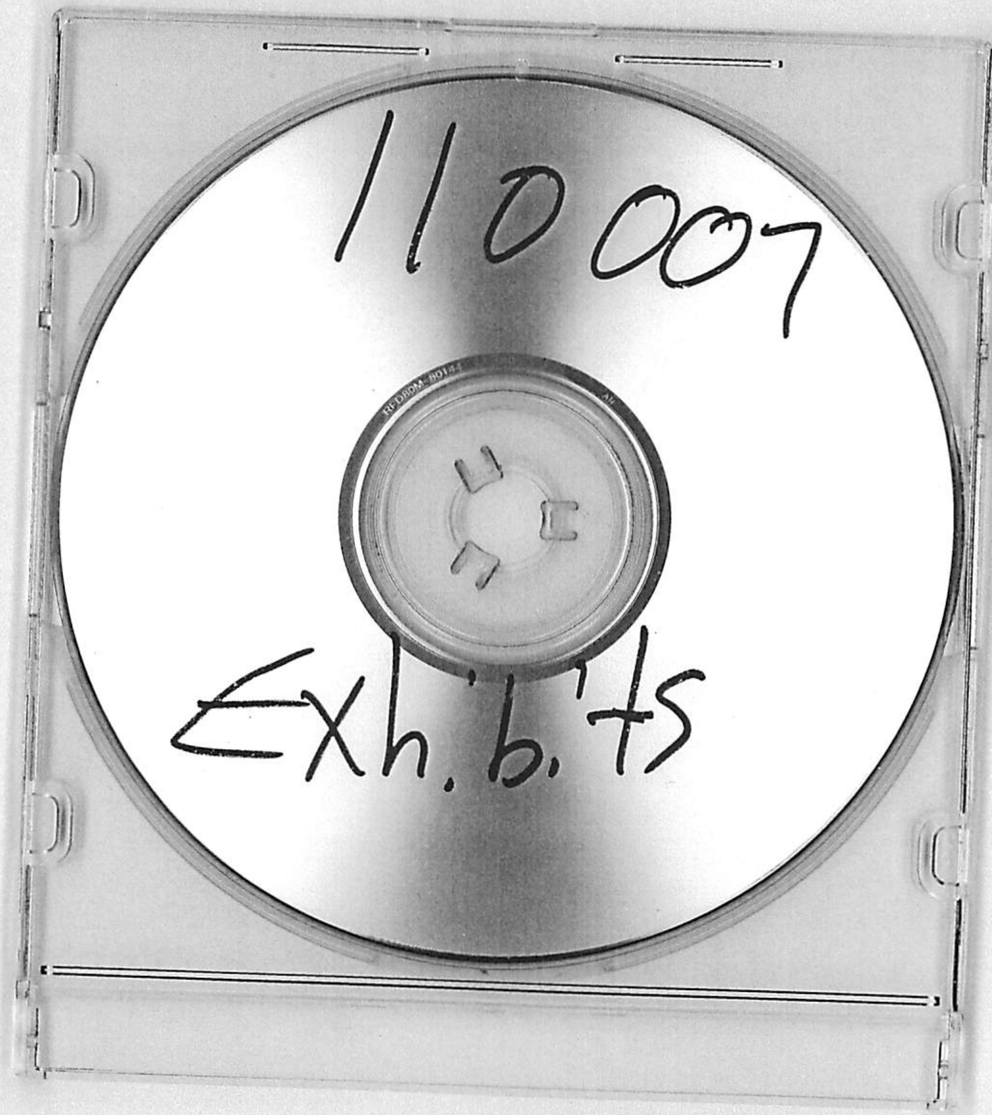
FPL Responses to Staff's First Set of Interrogatories (Nos. 1-36)

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI **EXHIBIT** 2
PARTY FLORIDA PUBLIC SERVICE COMMISSION STAFF
DESCRIPTION STAFF'S COMPOSITE EXHIBIT 2
DATE 11/01/11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Exhibits

APPENDIX I

ENVIRONMENTAL COST RECOVERY
COMMISSION FORMS 42-1A THROUGH 42-9A

JANUARY 2010 - DECEMBER 2010
FINAL TRUE-UP

TJK-1
DOCKET NO. 110007-EI
EXHIBIT________
PAGES 1-67

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI **EXHIBIT** 3
PARTY FLORIDA POWER & LIGHT COMPANY
DESCRIPTION T. J. KEITH (TJK-1)
DATE 11/01/11

Form 42-1A

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up
For the Period January 2010 through December 2010

Line No.				
1	Over/(Under) Recovery for the Current Period (Form 42-2A Page 2 of 2, Line 5)	$40,678,722		
2	Interest Provision (Form 42-2A Page 2 of 2, Line 6)	$78,595		
3	Total		$40,757,317	
4	Actual/Estimated Over/(Under) Recovery for the Same Period *	$35,632,441		
5	Interest Provision	88,450		
6	Total		$35,720,891	
7	Net True-Up for the period			$5,036,426

*Approved in FPSC Order No. PSC-11-0083-FOF-EI dated January 31, 2011.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January 2010 through December 2010

Form 42-2A
Page 1 of 2

Line No.		January	February	March	April	May	June
1	ECRC Revenues (net of Revenue Taxes)	$15,293,229	$12,507,180	$12,023,726	$11,407,926	$13,835,797	$16,740,007
2	True-up Provision (Order No. PSC-09-0759-FOF-EI)	524,748	524,748	524,748	524,748	524,748	524,748
3	ECRC Revenues Applicable to Period (Lines 1 + 2)	15,817,977	13,031,928	12,548,474	11,932,674	14,360,545	17,264,755
4	Jurisdictional ECRC Costs						
	a - O&M Activities (Form 42-5A, Line 9)	958,469	1,634,497	1,981,959	1,722,650	2,131,555	1,461,603
	b - Capital Investment Projects (Form 42-7A, Line 9)	8,933,817	9,301,070	8,601,781	9,141,769	9,602,004	9,901,278
	c - Total Jurisdictional ECRC Costs	9,892,286	10,935,567	10,583,740	10,864,419	11,733,559	11,362,881
5	Over/(Under) Recovery (Line 3 - Line 4c)	5,925,690	2,096,360	1,964,734	1,068,255	2,626,986	5,901,874
6	Interest Provision (Form 42-3A, Line 10)	2,250	2,901	3,237	3,573	4,944	7,061
7	Prior Periods True-Up to be (Collected)/Refunded in 2009	6,296,975	11,700,168	13,274,681	14,717,905	15,264,984	17,372,166
	a - Deferred True-Up from 2009 (Form 42-1A, Line 7)	4,500,433	4,500,433	4,500,433	4,500,433	4,500,433	4,500,433
8	True-Up Collected /(Refunded) (See Line 2)	(524,748)	(524,748)	(524,748)	(524,748)	(524,748)	(524,748)
9	End of Period True-Up (Lines 5+6+7+7a+8)	16,200,601	17,775,115	19,218,338	19,765,418	21,872,600	27,256,787
10	Adjustments to Period Total True-Up Including Interest						
11	End of Period Total Net True-Up (Lines 9+10)	$16,200,601	$17,775,115	$19,218,338	$19,765,418	$21,872,600	$27,256,787

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Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January 2010 through December 2010

Line No.		July	August	September	October	November	December	End of Period Amount
1	ECRC Revenues (net of Revenue Taxes)	$17,618,338	$17,402,894	$17,087,087	$14,789,950	$13,009,338	$13,220,401	$174,935,873
2	True-up Provision (Order No. PSC-09-0759-FOF-EI)	524,748	524,748	524,748	524,748	524,748	524,748	6,296,975
3	ECRC Revenues Applicable to Period (Lines 1 + 2)	18,143,086	17,927,642	17,611,835	15,314,697	13,534,086	13,745,149	181,232,848
4	Jurisdictional ECRC Costs							
	a - O&M Activities (Form 42-5A, Line 9)	1,715,483	980,141	1,559,461	1,174,335	2,176,588	3,582,734	21,079,475
	b - Capital Investment Projects (Form 42-7A, Line 9)	10,127,904	10,300,370	10,418,972	10,524,957	10,805,341	11,815,388	119,474,651
	c - Total Jurisdictional ECRC Costs	11,843,387	11,280,511	11,978,433	11,699,292	12,981,929	15,398,122	140,554,126
5	Over/(Under) Recovery (Line 3 - Line 4c)	6,299,699	6,647,131	5,633,402	3,615,405	552,157	(1,652,973)	40,678,722
6	Interest Provision (Form 42-3A, Line 10)	7,913	8,424	9,214	9,549	9,875	9,654	78,595
7	Prior Periods True-Up to be (Collected)/Refunded in 2009	22,756,354	28,539,218	34,670,025	39,787,893	42,888,100	42,925,384	6,296,975
	a - Deferred True-Up from 2009 (Form 42-1A, Line 7)	4,500,433	4,500,433	4,500,433	4,500,433	4,500,433	4,500,433	
8	True-Up Collected /(Refunded) (See Line 2)	(524,748)	(524,748)	(524,748)	(524,748)	(524,748)	(524,748)	(6,296,975)
9	End of Period True-Up (Lines 5+6+7+7a+8)	33,039,651	39,170,458	44,288,326	47,388,533	47,425,817	45,257,751	40,757,317
10	Adjustments to Period Total True-Up Including Interest							
11	End of Period Total Net True-Up (Lines 9+10)	$33,039,651	$39,170,458	$44,288,326	$47,388,533	$47,425,817	$45,257,751	$40,757,317

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January 2010 through December 2010

Interest Provision (in Dollars)

Line No.		January	February	March	April	May	June
1	Beginning True-Up Amount (Form 42-2A, Lines 7 + 7a + 10)	$10,797,408	$16,200,601	$17,775,115	$19,218,338	$19,765,418	$21,872,600
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	16,198,351	17,772,214	19,215,101	19,761,845	21,867,656	27,249,726
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	$26,995,759	$33,972,815	$36,990,216	$38,980,183	$41,633,074	$49,122,326
4	Average True-Up Amount (Line 3 x 1/2)	$13,497,880	$16,986,407	$18,495,108	$19,490,091	$20,816,537	$24,561,163
5	Interest Rate (First Day of Reporting Month)	0.20000%	0.20000%	0.21000%	0.21000%	0.23000%	0.34000%
6	Interest Rate (First Day of Subsequent Month)	0.20000%	0.21000%	0.21000%	0.23000%	0.34000%	0.35000%
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	0.40000%	0.41000%	0.42000%	0.44000%	0.57000%	0.69000%
8	Average Interest Rate (Line 7 x 1/2)	0.20000%	0.20500%	0.21000%	0.22000%	0.28500%	0.34500%
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.01667%	0.01708%	0.01750%	0.01833%	0.02375%	0.02875%
10	Interest Provision for the Month (Line 4 x Line 9)	$2,250	$2,901	$3,237	$3,573	$4,944	$7,061

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January 2010 through December 2010

Interest Provision (In Dollars)

Line No.		July	August	September	October	November	December	End of Period Amount
1	Beginning True-Up Amount (Form 42-2A, Lines 7 + 7a + 10)	$27,256,787	$33,039,651	$39,170,458	$44,288,326	$47,388,533	$47,425,817	N/A
2	Ending True-Up Amount before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	33,031,738	39,162,034	44,279,112	47,378,984	47,415,942	45,248,097	N/A
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	$60,288,526	$72,201,686	$83,449,571	$91,667,311	$94,804,475	$92,673,914	N/A
4	Average True-Up Amount (Line 3 x 1/2)	$30,144,263	$36,100,843	$41,724,785	$45,833,655	$47,402,238	$46,336,957	N/A
5	Interest Rate (First Day of Reporting Month)	0.35000%	0.28000%	0.28000%	0.25000%	0.25000%	0.25000%	N/A
6	Interest Rate (First Day of Subsequent Month)	0.28000%	0.28000%	0.25000%	0.25000%	0.25000%	0.25000%	N/A
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	0.63000%	0.56000%	0.53000%	0.50000%	0.50000%	0.50000%	N/A
8	Average Interest Rate (Line 7 x 1/2)	0.31500%	0.28000%	0.26500%	0.25000%	0.25000%	0.25000%	N/A
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.02625%	0.02333%	0.02208%	0.02083%	0.02083%	0.02083%	N/A
10	Interest Provision for the Month (Line 4 x Line 9)	$7,913	$8,424	$9,214	$9,549	$9,875	$9,654	$78,595

Form 42-4A

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-Up Amount for the Period
January 2010 - December 2010

Variance Report of O&M Activities
(In Dollars)

Line		(1) Actual	(2) Estimated Actual	(3) Variance Amount	(4) Variance Percent
1	Description of O&M Activities				
1	Air Operating Permit Fees-O&M	$1,335,682	$1,338,433	($2,751)	-0.2%
3a	Continuous Emission Monitoring Systems-O&M	$1,137,280	$1,217,205	($79,925)	-6.6%
5a	Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	$1,799,407	$2,194,365	($394,958)	-18.0%
8a	Oil Spill Cleanup/Response Equipment-O&M	$200,045	$197,600	$2,445	1.2%
13	RCRA Corrective Action-O&M	$1,851	$1,702	$149	8.8%
14	NPDES Permit Fees-O&M	$124,400	$124,400	$0	0.0%
17a	Disposal of Noncontainerized Liquid Waste-O&M	$184,823	$240,000	($55,177)	-23.0%
19a	Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	$1,472,406	$1,717,471	($245,065)	-14.3%
19b	Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	$787,230	$651,189	$136,041	20.9%
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	0.0%
NA	Amortization of Gains on Sales of Emissions Allowances	($249,269)	($249,269)	($0)	0.0%
21	St. Lucie Turtle Net	$0	$0	$0	0.0%
22	Pipeline Integrity Management	$362,642	$429,918	($67,276)	-15.6%
23	SPCC-Spill Prevention, Control & Countermeasures	$2,646,422	$2,561,123	$85,299	3.3%
24	Manatee Reburn	$522,903	$499,999	$22,904	4.6%
25	Port Everglades ESP	$877,373	$958,333	($80,960)	-8.4%
26	UST Replacement/Removal	$0	$0	$0	0.0%
27	Lowest Quality Water Source	$316,936	$311,192	$5,744	1.8%
28	CWA 316(b) Phase II Rule	$33,088	$44,217	($11,129)	-25.2%
29	SCR Consumables	$342,888	$373,849	($30,961)	-8.3%
30	HBMP	$19,797	$19,578	$219	1.1%
31	CAIR Compliance	$2,417,817	$2,571,128	($153,311)	-6.0%
32	BART	$0	$0	$0	0.0%
33	CAMR Compliance	$1,590,467	$2,470,373	($879,906)	-35.6%
34	St. Lucie Cooling Water System Inspection & Maintenance	$1,129,351	$994,905	$134,446	13.5%
35	Martin Plant Drinking Water System Compliance	$30,250	$25,000	$5,250	21.0%
36	Low-Level Radioactive Waste Storage	$0	$0	$0	0.0%
37	DeSoto Next Generation Solar Energy Center	$979,233	$1,012,678	($33,445)	-3.3%
38	Space Coast Next Generation Solar Energy Center	$314,174	$444,536	($130,362)	-29.3%
39	Martin Next Generation Solar Energy Center	$8,941	$0	$8,941	N/A
40	Greenhouse Gas Reduction Program	$0	$59,000	($59,000)	-100.0%
41	Manatee Temporary Heating System Project	$699,024	$239,663	$459,361	191.7%
42	Turkey Point Cooling Canal Monitoring Plan	$1,756,536	$2,195,080	($438,544)	-20.0%
43	NESHAP Information Collection Request Project	$1,197,928	$1,190,773	$7,155	0.6%
2	Total O&M Activities	$21,479,395	$23,274,209	($1,794,814)	-7.7%
3	Recoverable Costs Allocated to Energy	$ 12,052,506	$ 13,330,711	($1,278,205)	-9.6%
4a	Recoverable Costs Allocated to CP Demand	$ 8,234,598	$ 8,506,143	($271,545)	-3.2%
4b	Recoverable Costs Allocated to GCP Demand	$ 1,192,290	$ 1,437,355	($245,065)	-17.0%

Notes:
Column(1) is the 12-Month Totals on Form 42-5A
Column(2) is the approved actual/estimated 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 Final True-up Amount for the Period
January 2010 - December 2010

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	$ 106,712	$ 198,115	$ 107,295	$ 107,295	$ 102,377	$ 102,377	$724,171
3a Continuous Emission Monitoring Systems-O&M	191,345	30,785	46,153	80,010	143,429	34,515	526,237
5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	29,891	199,153	402,723	357,589	217,548	134,232	1,341,134
8a Oil Spill Cleanup/Response Equipment-O&M	29,627	13,135	12,026	13,836	7,612	15,910	92,146
13 RCRA Corrective Action-O&M	0	2,000	0	0	0	(298)	1,702
14 NPDES Permit Fees-O&M	112,900	0	0	11,500	0	0	124,400
17a Disposal of Noncontainerized Liquid Waste-O&M	0	2,411	30,544	66,410	30,979	(75)	130,269
19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	127,548	150,318	132,029	138,019	86,360	67,196	701,471
19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	49,988	62,589	38,033	26,952	30,614	63,012	271,189
19c Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(280,116)
20 Wastewater Discharge Elimination &Reuse	0	0	0	0	0	0	0
NA Amortization of Gains on Sales of Emissions Allowances	(14,461)	(14,461)	(14,461)	(36,755)	(20,034)	(24,706)	(124,878)
21 St. Lucie Turtle Nei	0	0	0	0	0	0	0
22 Pipeline Integrity Managemen	78	6,200	94,216	775	1,427	11,703	114,399
23 SPCC - Spill Prevention, Control & Countermeasure	51,661	39,389	123,503	59,281	97,333	77,265	448,432
24 Manatee Reburr	3,733	143,426	8,026	146,776	42,013	9,636	353,609
25 Pt. Everglades ESP Technology	56,742	99,528	21,855	40,195	48,178	111,296	377,793
26 UST Replacement/Remova	0	0	0	0	0	0	0
27 Lowest Quality Water Source	27,731	25,140	25,114	26,657	26,922	25,331	156,895
28 CWA 316(b) Phase II Rule	4,150	2,546	(55)	(353,199)	353,586	(1,713)	5,315
29 SCR Consumables	21,394	21,180	31,958	74,749	20,867	21,636	191,785
30 HBMP	1,631	1,637	1,631	1,631	1,631	1,637	9,798
31 CAIR Compliance	192,206	463,795	200,761	132,204	76,977	73,144	1,139,087
32 BART Compliance	0	0	0	0	0	0	0
33 CAMR Compliance	0	0	0	0	194,398	338,510	532,908
34 St. Lucie Cooling Water System Inspection & Maintenanc	8,359	14,522	131,594	350,354	426,584	40,771	972,185
35 Martin Plant Drinking Water System Complianc	0	3,641	0	0	10,533	0	14,174
36 Low-Level Radioactive Waste Storage	0	0	0	0	0	0	0
37 DeSoto Next Generation Solar Energy Cente	8,495	67,037	91,695	93,771	72,809	83,108	416,915
38 Space Coast Next Generation Solar Energy Cente	5,143	1,515	2,113	8,198	18,943	31,673	67,584
39 Martin Next Generation Solar Energy Cente	0	0	0	0	0	0	0
40 Greenhouse Gas Reduction Progran	0	0	0		0	0	0
41 Manatee Temporary Heating System Projec	0	9,852	0	5,549	1,312	524	17,237
42 Turkey Point Cooling Canal Monitoring Plar	7,463	166,056	108,833	130,117	7,340	213,270	635,080
43 NESHAP Information Collection Request Projeci	0	0	470,725	319,762	220,086	106,850	1,117,424
2 Total of O&M Activities	$ 975,651	$ 1,664,822	$ 2,019,625	$ 1,754,989	$ 2,173,137	$ 1,490,118	$ 10,078,342
3 Recoverable Costs Allocated to Energy	$ 596,812	$ 1,138,639	$ 1,024,846	$ 1,080,426	$ 876,093	$ 1,005,938	$ 5,722,954
4a Recoverable Costs Allocated to CP Demand	$ 274,634	$ 399,008	$ 886,093	$ 559,888	$ 1,234,026	$ 440,328	$ 3,793,976
4b Recoverable Costs Allocated to GCP Demand	$ 104,205	$ 126,975	$ 108,686	$ 114,676	$ 63,017	$ 43,853	$ 561,413
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)	$ 585,037	$ 1,116,371	$ 1,004,627	$ 1,059,110	$ 858,809	$ 986,092	$ 5,610,046
8a Jurisdictional CP Demand Recoverable Costs (B)	$ 269,227	$ 391,151	$ 868,648	$ 548,864	$ 1,209,729	$ 431,658	$ 3,719,275
8b Jurisdictional GCP Demand Recoverable Costs (C)	$ 104,205	$ 126,975	$ 108,686	$ 114,676	$ 63,017	$ 43,853	$ 561,412
9 Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 958,469	$ 1,634,497	$ 1,981,959	$ 1,722,650	$ 2,131,555	$ 1,461,603	$ 9,890,733

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

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January 2010 - December 2010

O&M Activities
(in Dollars)

Line # Project #	Actual JUL	Actual AUG	Actual SEP	Actual OCT	Actual NOV	Actual DEC	6-Month Sub-Total	12-Month Total	Method of Classification CP Demand	GCP Demand	Energy
1 Description of O&M Activities											
1 Air Operating Permit Fees-O&M	$ 102,377	$ 102,377	$ 102,377	$ 101,460	$ 101,460	$ 101,460	$611,511	$1,335,682			$1,335,682
3a Continuous Emission Monitoring Systems-O&M	156,387	64,161	80,751	139,351	69,592	100,802	611,043	1,137,280			1,137,280
5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	91,710	14,134	43,450	15,526	91,289	202,164	458,274	1,799,407	1,799,407		
8a Oil Spill Cleanup/Response Equipment-O&M	16,275	12,747	13,762	4,324	21,332	39,459	107,899	200,045			200,045
13 RCRA Corrective Action-O&M	149	0	0	0	0	0	149	1,851	1,851		
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	24,754	29,599	0	0	0	201	54,554	184,823			184,823
19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	92,598	58,409	162,439	98,503	64,324	294,662	770,936	1,472,406		1,472,406	
19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	38,702	73,881	17,446	12,996	72,934	300,082	516,042	787,230	726,674		60,556
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	(20,529)	(20,772)	(20,772)	(20,772)	(20,772)	(20,772)	(124,391)	(249,269)			(249,269)
21 St. Lucie Turtle Net	0	0	0	0	0	0	0	0	0		
22 Pipeline Integrity Management	0	11,280	28,067	62,519	88,022	58,354	248,243	362,642	362,642		
23 SPCC - Spill Prevention, Control & Countermeasures	136,033	110,398	214,895	81,064	802,053	853,545	2,197,989	2,646,422	2,646,422		
24 Manatee Reburn	4,561	2,241	12,176	10,923	87,507	51,885	169,294	522,903			522,903
25 Pt. Everglades ESP Technology	54,958	37,933	36,282	34,364	26,268	309,776	499,580	877,373			877,373
26 UST Replacement/Removal	0	0	0	0	0	0	0	0	0		
27 Lowest Quality Water Source	26,967	26,289	26,729	27,102	26,852	26,102	160,041	316,936	316,936		
28 CWA 316(b) Phase II Rule	856	0	6,988	1,812	6,774	11,344	27,774	33,088	33,088		
29 SCR Consumables	13,651	22,511	21,152	13,375	52,458	27,957	151,104	342,888			342,888
30 HBMP	1,631	1,637	1,631	1,659	1,720	1,720	9,999	19,797	19,797		
31 CAIR Compliance	451,285	86,864	201,786	197,067	164,591	177,137	1,278,730	2,417,817			2,417,817
32 BART Compliance	0	0	0	0	0	0	0	0			0
33 CAMR Compliance	178,718	64,445	293,300	156,374	195,070	169,653	1,057,559	1,590,467			1,590,467
34 St. Lucie Cooling Water System Inspection & Maintenance	151,724	1,000	366	0	221	3,855	157,167	1,129,351	1,129,351		
35 Martin Plant Drinking Water System Compliance	0	1,848	1,848	0	1,848	10,533	16,076	30,250	30,250		
36 Low-Level Radioactive Waste Storage	0	0	0	0	0	0	0	0	0		0
37 DeSoto Next Generation Solar Energy Center	124,242	90,496	115,555	70,832	82,265	78,928	562,319	979,233	979,233		
38 Space Coast Next Generation Solar Energy Center	35,521	39,369	48,641	40,998	34,115	47,946	246,590	314,174	314,174		
39 Martin Next Generation Solar Energy Center	0	0	0	0	0	8,941	8,941	8,941	8,941		
40 Greenhouse Gas Reduction Program	0	0	0	0	0	0	0	0			0
41 Manatee Temporary Heating System Project	100	0	18,280	39,432	42,470	581,505	681,787	699,024			699,024
42 Turkey Point Cooling Canal Monitoring Plan	102,025	174,083	192,779	153,269	244,976	254,325	1,121,457	1,756,536			1,756,536
43 NESHAP Information Collection Request Project	10,580	40,903	14,786	955	8,840	4,440	80,504	1,197,928			1,197,928
2 Total of O&M Activities	$ 1,748,591	$ 999,148	$ 1,588,029	$ 1,196,446	$ 2,219,521	$ 3,649,317	$ 11,401,052	$ 21,479,395	$ 8,234,598	$ 1,192,290	$ 12,052,506
3 Recoverable Costs Allocated to Energy	$ 1,096,324	$ 620,978	$ 966,206	$ 829,324	$ 997,605	$ 1,819,114	$ 6,329,552	$ 12,052,506			
4a Recoverable Costs Allocated to CP Demand	$ 583,012	$ 343,103	$ 482,727	$ 291,962	$ 1,180,935	$ 1,558,884	$ 4,440,623	$ 8,234,598			
4b Recoverable Costs Allocated to GCP Demand	$ 69,255	$ 35,066	$ 139,096	$ 75,160	$ 40,981	$ 271,319	$ 630,878	$ 1,192,290			
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)	$ 1,074,695	$ 608,727	$ 947,143	$ 812,962	$ 977,924	$ 1,783,225	$ 6,204,676	$ 11,814,722			
8a Jurisdictional CP Demand Recoverable Costs (B)	$ 571,533	$ 336,348	$ 473,222	$ 286,213	$ 1,157,683	$ 1,528,190	$ 4,353,189	$ 8,072,464			
8b Jurisdictional GCP Demand Recoverable Costs (C)	$ 69,255	$ 35,066	$ 139,096	$ 75,160	$ 40,981	$ 271,319	$ 630,877	$ 1,192,289			
9 Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 1,715,483	$ 980,141	$ 1,559,461	$ 1,174,335	$ 2,176,588	$ 3,582,734	$ 11,188,742	$ 21,079,475			

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

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-Up Amount for the Period
January 2010 - December 2010

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

Line		(1) Actual	(2) Estimated Actual	(3) Variance Amount	(4) Variance Percent
1	Description of Investment Projects				
2	Low NOx Burner Technology-Capital	$379,686	$379,686	$0	0.0%
3b	Continuous Emission Monitoring Systems-Capital	$728,468	$729,186	($718)	-0.1%
4b	Clean Closure Equivalency-Capital	$2,399	$2,399	$0	0.0%
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	$1,137,182	$1,140,960	($3,778)	-0.3%
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	$1,707	$1,707	($0)	0.0%
8b	Oil Spill Cleanup/Response Equipment-Capital	$101,549	$109,061	($7,512)	-6.9%
10	Relocate Storm Water Runoff-Capital	$8,797	$8,797	($0)	0.0%
NA	SO2 Allowances-Negative Return on Investment	($212,715)	($212,715)	$0	0.0%
12	Scherer Discharge Pipeline-Capital	$60,238	$60,238	$0	0.0%
20	Wastewater Discharge Elimination & Reuse	$140,732	$145,645	($4,913)	-3.4%
21	St. Lucie Turtle Net	$109,226	$109,226	($0)	0.0%
23	SPCC-Spill Prevention, Control & Countermeasures	$2,078,731	$2,076,350	$2,381	0.1%
24	Manatee Reburn	$3,535,476	$3,536,101	($625)	0.0%
25	Pt. Everglades ESP Technology	$8,578,072	$8,578,072	($0)	0.0%
26	UST Replacement/Removal	$55,516	$55,516	$0	0.0%
31	CAIR Compliance	$37,332,055	$37,445,111	($113,056)	-0.3%
33	CAMR Compliance	$11,531,103	$11,617,212	($86,109)	-0.7%
35	Martin Plant Drinking Water System Compliance	$27,523	$27,523	$0	0.0%
36	Low-Level Radioactive Waste Storage	$0	$19,671	($19,671)	-100.0%
37	DeSoto Next Generation Solar Energy Center	$18,484,719	$18,488,420	($3,701)	0.0%
38	Space Coast Next Generation Solar Energy Center	$7,781,526	$7,805,893	($24,367)	-0.3%
39	Martin Next Generation Solar Energy Center	$29,550,752	$30,287,664	($736,912)	-2.4%
41	Manatee Temporary Heating System Project	$445,352	$340,307	$105,045	30.9%
42	Turkey Point Cooling Canal Monitoring Plan	$17,062	$129,307	($112,245)	-86.8%
2	Total Investment Projects-Recoverable Costs	$ 121,875,156	$ 122,881,337	$ (1,006,181)	-0.8%
3	Recoverable Costs Allocated to Energy	$ 21,383,308	$ 21,461,945	$ (78,637)	-0.4%
4	Recoverable Costs Allocated to Demand	$ 100,491,849	$ 101,419,392	$ (927,543)	-0.9%

Notes:
Column(1) is the 12-Month Totals on Form 42-7A
Column(2) is the approved actual/estimated 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 Final True-up Amount for the Period
January 2010 - December 2010

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	$39,086	$38,903	$36,167	$32,900	$29,632	$ 29,474	$ 206,163
3b Continuous Emission Monitoring Systems-Capital	69,152	69,256	63,023	61,025	59,026	58,830	380,313
4b Clean Closure Equivalency-Capital	260	259	233	208	182	181	1,323
5b Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	114,360	114,145	101,720	95,008	88,882	89,691	603,805
7 Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	155	155	142	141	141	140	875
8b Oil Spill Cleanup/Response Equipment-Capital	8,947	8,588	8,432	8,381	8,446	8,286	51,080
10 Relocate Storm Water Runoff-Capital	812	811	724	722	721	720	4,509
NA SO2 Allowances-Negative Return on Investment	(20,499)	(20,366)	(17,505)	(17,583)	(17,638)	(17,496)	(111,087)
12 Scherer Discharge Pipeline-Capital	5,530	5,514	4,978	4,965	4,952	4,939	30,879
20 Wastewater Discharge Elimination & Reuse	18,012	17,992	15,846	12,610	9,375	9,357	83,193
21 St. Lucie Turtle Net	9,990	10,231	8,919	8,915	8,911	8,907	55,874
23 SPCC - Spill Prevention, Control & Countermeasures	187,473	200,030	180,709	174,368	164,964	166,046	1,073,591
24 Manatee Reburn	326,684	326,034	291,000	290,438	289,785	289,133	1,813,074
25 Pt. Everglades ESP Technology	793,711	792,267	704,692	703,459	702,245	701,030	4,397,404
26 UST Removal / Replacement	5,145	5,137	4,554	4,547	4,541	4,534	28,459
31 CAIR Compliance	2,801,397	2,881,786	2,658,825	2,830,883	2,988,546	3,121,664	17,283,101
33 CAMR Compliance	811,905	829,166	742,133	874,354	1,002,195	1,011,360	5,271,113
35 Martin Plant Drinking Water System Compliance	2,552	2,548	2,257	2,254	2,251	2,247	14,109
36 Low-Level Radioactive Waste Storage	0	0	0	0	0	0	0
37 DeSoto Next Generation Solar Energy Center	1,641,086	1,630,694	1,539,381	1,530,484	1,526,926	1,524,849	9,393,419
38 Space Coast Next Generation Solar Energy Center	418,210	515,352	504,192	634,237	686,807	721,154	3,479,952
39 Martin Next Generation Solar Energy Center	1,850,731	2,030,888	1,895,356	2,046,736	2,207,529	2,338,543	12,369,783
41 Manatee Temporary Heating System Project	28,625	28,565	28,837	26,397	26,511	26,626	165,561
42 Turkey Point Cooling Canal Monitoring Plan	0	0	0	0	0	0	0
2 Total Investment Projects - Recoverable Costs	$ 9,113,326	$ 9,487,955	$ 8,774,616	$ 9,325,450	$ 9,794,929	$ 10,100,215	$ 56,596,491
3 Recoverable Costs Allocated to Energy	$ 1,816,226	$ 1,843,161	$ 1,669,472	$ 1,705,255	$ 1,734,733	$ 1,756,298	$ 10,525,146
4 Recoverable Costs Allocated to Demand	$ 7,297,101	$ 7,644,794	$ 7,105,143	$ 7,620,195	$ 8,060,196	$ 8,343,917	$ 46,071,345
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)	$ 1,780,393	$ 1,806,798	$ 1,636,535	$ 1,671,612	$ 1,700,509	$ 1,721,648	$ 10,317,495
8 Jurisdictional Demand Recoverable Costs (C)	$ 7,153,424	$ 7,494,272	$ 6,965,246	$ 7,470,157	$ 7,901,495	$ 8,179,630	$ 45,164,224
9 Total Jurisdictional Recoverable Costs fo Investment Projects (Lines 7 + 8)	$ 8,933,817	$ 9,301,070	$ 8,601,781	$ 9,141,769	$ 9,602,004	$ 9,901,278	$ 55,481,719

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

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Final True-up Amount for the Period
January 2010 - December 2010

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line # Project #	Actual JUL	Actual AUG	Actual SEP	Actual OCT	Actual NOV	Actual DEC	6-Month Sub-Total	12-Month Total	Method of Classification Demand	Method of Classification Energy
1 Description of Investment Projects (A)										
2 Low NOx Burner Technology-Capital	$ 29,316	$ 29,158	$ 29,000	$ 28,841	$ 28,683	$ 28,525	$ 173,523	$ 379,686		$ 379,686
3b Continuous Emission Monitoring Systems-Capital	58,633	58,453	57,615	58,013	57,818	57,623	348,155	728,468		728,468
4b Clean Closure Equivalency-Capital	181	180	180	179	179	178	1,076	2,399	2,215	184
5b Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	89,934	89,706	89,457	88,676	87,896	87,708	533,377	1,137,182	1,049,707	87,475
7 Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	140	139	139	138	138	137	832	1,707	1,576	131
8b Oil Spill Cleanup/Response Equipment-Capital	8,210	8,153	8,077	8,637	8,526	8,866	50,469	101,549	93,738	7,811
10 Relocate Storm Water Runoff-Capital	718	717	715	714	712	711	4,287	8,797	8,120	677
NA SO2 Allowances-Negative Return on Investment	(17,353)	(17,187)	(17,021)	(16,855)	(16,689)	(16,523)	(101,628)	(212,715)		(212,715)
12 Scherer Discharge Pipeline-Capital	4,926	4,913	4,900	4,887	4,874	4,861	29,360	60,238	55,605	4,633
20 Wastewater Discharge Elimination &Reuse	9,340	9,322	9,305	9,287	9,269	11,017	57,539	140,732	129,906	10,826
21 St. Lucie Turtle Net	8,903	8,898	8,894	8,890	8,886	8,881	53,352	109,226	100,824	8,402
23 SPCC - Spill Prevention, Control & Countermeasures	166,972	167,055	167,134	167,419	167,703	168,858	1,005,140	2,078,731	1,918,829	159,902
24 Manatee Reburn	288,572	288,012	287,451	286,891	286,330	285,145	1,722,403	3,535,476		3,535,476
25 Pt. Everglades ESP Technology	699,815	698,600	697,385	696,171	694,956	693,741	4,180,668	8,578,072		8,578,072
26 UST Removal / Replacement	4,527	4,520	4,513	4,506	4,499	4,492	27,057	55,516	51,246	4,270
31 CAIR Compliance	3,202,015	3,259,609	3,311,840	3,357,947	3,414,189	3,503,353	20,048,954	37,332,055	34,460,358	2,871,697
33 CAMR Compliance	1,020,298	1,032,167	1,037,501	1,049,386	1,059,901	1,060,739	6,259,991	11,531,103	10,644,095	887,008
35 Martin Plant Drinking Water System Compliance	2,244	2,241	2,237	2,234	2,231	2,227	13,414	27,523	25,406	2,117
36 Low-Level Radioactive Waste Storage	0	0	0	0	0	0	0	0	0	0
37 DeSoto Next Generation Solar Energy Cente	1,523,267	1,520,396	1,516,790	1,513,180	1,511,298	1,506,369	9,091,300	18,484,719	17,062,817	1,421,902
38 Space Coast Next Generation Solar Energy Cente	719,990	718,706	717,147	715,864	714,600	715,268	4,301,574	7,781,526	7,182,947	598,579
39 Martin Next Generation Solar Energy Cente	2,484,131	2,596,965	2,653,744	2,693,848	2,914,176	3,838,105	17,180,969	29,550,752	27,277,617	2,273,135
41 Manatee Temporary Heating System Project	26,617	26,601	41,308	57,568	62,263	65,433	279,790	445,352	411,094	34,258
42 Turkey Point Cooling Canal Monitoring Plar	0	0	0	0	0	17,062	17,062	17,062	15,749	1,313
2 Total Investment Projects - Recoverable Costs	$10,331,395	$10,507,324	$10,628,309	$10,736,422	$11,022,440	$12,052,776	$65,278,665	$121,875,156	$100,491,849	$21,383,307
3 Recoverable Costs Allocated to Energy	$ 1,772,246	$ 1,783,981	$ 1,790,882	$ 1,797,935	$ 1,818,125	$ 1,894,993	$10,858,162	$ 21,383,308		
4 Recoverable Costs Allocated to Demand	$ 8,559,149	$ 8,723,343	$ 8,837,427	$ 8,938,487	$ 9,204,315	$ 10,157,783	$54,420,503	$ 100,491,849		
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)	$ 1,737,281	$ 1,748,785	$ 1,755,550	$ 1,762,464	$ 1,782,255	$ 1,857,607	$10,643,942	$ 20,961,437		
8 Jurisdictional Demand Recoverable Costs (C)	$ 8,390,623	$ 8,551,585	$ 8,663,422	$ 8,762,493	$ 9,023,086	$ 9,957,781	$53,348,990	$ 98,513,214		
9 Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$10,127,904	$10,300,370	$10,418,972	$10,524,957	$10,805,341	$11,815,388	$63,992,932	$119,474,651		

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

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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

Line		Beginning of Period Amount	January 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	($7,062,729)	$0	$0	($7,062,729)
	c. Retirements		$0	$0	$0	($6,285,607)	$0	$0	($6,285,607)
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$16,959,531	16,959,531	16,959,531	16,959,531	9,896,803	9,896,803	9,896,803	n/a
3.	Less: Accumulated Depreciation	$14,861,547	14,881,323	14,901,098	14,920,873	8,655,041	8,674,816	8,694,592	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$2,097,984	$2,078,209	$2,058,433	$2,038,658	$1,241,762	$1,221,986	$1,202,211	n/a
6.	Average Net Investment		2,088,096	2,068,321	2,048,546	1,640,210	1,231,874	1,212,099	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		16,045	15,893	13,068	10,463	7,858	7,732	$71,059
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		3,266	3,235	3,324	2,662	1,999	1,967	$16,452
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)		$39,086	$38,903	$36,167	$32,900	$29,632	$29,474	$206,163

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 42-8A, pages 49-53.
(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	($7,062,729)
	c. Retirements		$0	$0	$0	($0)	$0	$0	($6,285,607)
	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	$8,694,592	8,714,367	8,734,142	8,753,918	8,773,693	8,793,468	8,813,243	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,202,211	$1,182,436	$1,162,661	$1,142,885	$1,123,110	$1,103,335	$1,083,559	n/a
6.	Average Net Investment		1,192,324	1,172,548	1,152,773	1,132,998	1,113,222	1,093,447	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		7,606	7,480	7,354	7,227	7,101	6,975	114,802
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		1,935	1,903	1,871	1,839	1,807	1,774	27,580
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)		$29,316	$29,158	$29,000	$28,841	$28,683	$28,525	$379,686

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 42-8A, pages 49-53.
(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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

Line		Beginning of Period Amount	January 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		$102,977	$0	$0	($1,737,945)	$0	$0	($1,634,967)
	c. Retirements		$31,642	$0	$0	($1,287,349)	$0	$0	($1,255,708)
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$11,866,572	11,969,550	11,969,550	11,969,550	10,231,605	10,231,605	10,231,605	n/a
3.	Less: Accumulated Depreciation	$7,057,138	7,113,238	7,137,695	7,162,153	5,899,261	5,923,719	5,948,176	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$4,809,434	$4,856,312	$4,831,855	$4,807,397	$4,332,344	$4,307,887	$4,283,429	n/a
6.	Average Net Investment		4,832,873	4,844,083	4,819,626	4,569,870	4,320,115	4,295,658	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		37,137	37,223	30,744	29,151	27,558	27,402	$189,215
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		7,558	7,576	7,821	7,416	7,011	6,971	$44,353
8.	Investment Expenses								
	a. Depreciation (E)		24,458	24,458	24,458	24,458	24,457	24,457	$146,745
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$69,152	$69,256	$63,023	$61,025	$59,026	$58,830	$380,313

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 42-8A, pages 49-53.
(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		($1,313)	$2,283	($100)	$0	$0	$0	($1,634,097)
	c. Retirements		($1,313)	$162	$0	$0	$0	$0	($1,256,858)
	d. Other		-	162.47	-	0.02	-	-	
2.	Plant-In-Service/Depreciation Base (A)	$10,231,605	10,230,292	10,232,575	10,232,475	10,232,475	10,232,475	10,232,475	n/a
3.	Less: Accumulated Depreciation	$5,948,176	5,971,318	5,995,944	6,019,754	6,044,155	6,068,557	6,092,959	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$4,283,429	$4,258,974	$4,236,631	$4,212,721	$4,188,320	$4,163,918	$4,139,517	n/a
6.	Average Net Investment		4,271,201	4,247,802	4,224,676	4,200,521	4,176,119	4,151,717	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		27,248	27,097	26,949	26,795	26,639	26,484	350,425
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		6,931	6,893	6,856	6,817	6,777	6,737	85,364
8.	Investment Expenses								
	a. Depreciation (E)		24,455	24,463	23,810	24,402	24,402	24,402	292,678
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$58,633	$58,453	$57,615	$58,013	$57,818	$57,623	$728,468

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 42-8A, pages 49-53.

(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6840% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.

(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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

Line		Beginning of Period Amount	January 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	($17,254)	$0	$0	($17,254)
	c. Retirements		$0	$0	$0	($10,983)	$0	$0	($10,983)
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$58,866	58,866	58,866	58,866	41,612	41,612	41,612	n/a
3.	Less: Accumulated Depreciation	$38,240	38,310	38,379	38,449	27,535	27,605	27,674	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$20,626	$20,556	$20,487	$20,417	$14,077	$14,007	$13,938	n/a
6.	Average Net Investment		20,591	20,521	20,452	17,247	14,042	13,972	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		158	158	130	110	90	89	$735
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		32	32	33	28	23	23	$171
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)		$260	$259	$233	$208	$182	$181	$1,323

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 42-8A, pages 49-53.
(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	($17,254)
	c. Retirements		$0	$0	$0	$0	$0	$0	($10,983)
	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	$27,674	27,744	27,813	27,883	27,952	28,022	28,091	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$13,938	$13,868	$13,799	$13,729	$13,659	$13,590	$13,520	n/a
6.	Average Net Investment		13,903	13,833	13,764	13,694	13,625	13,555	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		89	88	88	87	87	86	1,281
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		23	22	22	22	22	22	305
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)		$181	$180	$180	$179	$179	$178	$2,399

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 42-8A, pages 49-53.

(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.

(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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

Line		Beginning of Period Amount	January 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	($1,982,992)	$115,155	$80,431	($1,787,406)
	c. Retirements		$0	$0	$0	($352,190)	$0	$0	($352,190)
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$13,644,547	13,644,547	13,644,547	13,644,547	11,661,555	11,776,710	11,857,141	n/a
3.	Less: Accumulated Depreciation	$3,789,558	3,812,887	3,836,215	3,859,544	3,530,683	3,554,136	3,577,804	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$9,854,989	$9,831,660	$9,808,331	$9,785,003	$8,130,872	$8,222,574	$8,279,337	n/a
6.	Average Net Investment		9,843,324	9,819,996	9,796,667	8,957,938	8,176,723	8,250,955	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		75,638	75,458	62,493	57,143	52,159	52,633	$375,524
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		15,394	15,357	15,898	14,537	13,269	13,390	$87,845
8.	Investment Expenses								
	a. Depreciation (E)		23,329	23,329	23,329	23,329	23,453	23,668	$140,436
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$114,360	$114,145	$101,720	$95,008	$88,882	$89,691	$603,805

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 42-8A, pages 49-53.

(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.

(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$4,187	($11,593)	$22	($116,447)	($4)	$10	($1,911,230)
	c. Retirements		$0	$0	$0	$0	$0	$0	($352,190)
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$11,857,141	11,861,328	11,849,735	11,849,757	11,733,310	11,733,307	11,733,316	n/a
3.	Less: Accumulated Depreciation	$3,577,804	3,601,567	3,625,322	3,649,064	3,672,680	3,696,170	3,719,660	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$8,279,337	$8,259,761	$8,224,413	$8,200,693	$8,060,630	$8,037,136	$8,013,656	n/a
6.	Average Net Investment		8,269,549	8,242,087	8,212,553	8,130,662	8,048,883	8,025,396	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		52,751	52,576	52,388	51,865	51,344	51,194	687,643
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		13,420	13,375	13,327	13,194	13,062	13,024	167,247
8.	Investment Expenses								
	a. Depreciation (E)		23,763	23,755	23,742	23,616	23,490	23,490	282,292
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$89,934	$89,706	$89,457	$88,676	$87,896	$87,708	$1,137,182

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 42-8A, pages 49-53.
(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6840% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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

Line		Beginning of Period Amount	January 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	$20,899	20,961	21,023	21,085	21,147	21,209	21,271	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$10,131	$10,069	$10,007	$9,945	$9,883	$9,821	$9,759	n/a
6.	Average Net Investment		10,100	10,038	9,976	9,914	9,852	9,790	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		78	77	64	63	63	62	$407
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		16	16	16	16	16	16	$96
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)		$155	$155	$142	$141	$141	$140	$875

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 42-8A, pages 49-53.
(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
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	$21,271	21,333	21,395	21,457	21,519	21,581	21,643	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$9,759	$9,697	$9,635	$9,573	$9,511	$9,449	$9,387	n/a
6.	Average Net Investment		9,728	9,666	9,604	9,542	9,480	9,418	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		62	62	61	61	60	60	773
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		16	16	16	15	15	15	189
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)		$140	$139	$139	$138	$138	$137	$1,707

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 42-8A, pages 49-53.

(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.

(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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

Line		Beginning of Period Amount	January 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		$24,380	($3,200)	($3,563)	$0	($1,667)	$0	$15,950
	c. Retirements		$8,852	$0	($4,363)	$0	($2,467)	$0	$2,023
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$485,893	510,273	507,073	503,511	503,511	501,844	501,844	n/a
3.	Less: Accumulated Depreciation	$205,264	220,425	226,375	228,219	234,422	238,270	244,472	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$280,629	$289,848	$280,699	$275,291	$269,089	$263,573	$257,371	n/a
6.	Average Net Investment		285,239	285,274	277,995	272,190	266,331	260,472	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		2,192	2,192	1,773	1,736	1,699	1,662	$11,254
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		446	446	451	442	432	423	$2,640
8.	Investment Expenses								
	a. Depreciation (E)		6,309	5,949	6,208	6,203	6,315	6,202	$37,186
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$8,947	$8,588	$8,432	$8,381	$8,446	$8,286	$51,080

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 42-8A, pages 49-53.

(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6840% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.

(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$1,939	$1	$3,173	$27,721	$5,465	$54,250
	c. Retirements		$0	($1,943)	$0	($7,776)	$0	($3,364)	($11,061)
	d. Other								0
2.	Plant-In-Service/Depreciation Base (A)	$501,844	501,844	503,783	503,783	506,957	534,678	540,143	n/a
3.	Less: Accumulated Depreciation	$244,472	250,647	254,856	260,965	259,867	266,331	269,677	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$257,371	$251,196	$248,927	$242,818	$247,090	$268,347	$270,466	n/a
6.	Average Net Investment		254,284	250,062	245,873	244,954	257,719	269,407	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		1,622	1,595	1,568	1,563	1,644	1,719	20,965
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		413	406	399	398	418	437	5,110
8.	Investment Expenses								
	a. Depreciation (E)		6,175	6,152	6,110	6,677	6,464	6,710	75,474
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$8,210	$8,153	$8,077	$8,637	$8,526	$8,866	$101,549

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 42-8A, pages 49-53.

(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.

(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

Return on Capital Investments, Depreciation and Taxes
For Project: 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	$48,985	49,162	49,339	49,515	49,692	49,869	50,045	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$68,809	$68,632	$68,455	$68,278	$68,102	$67,925	$67,748	n/a
6.	Average Net Investment		68,720	68,543	68,367	68,190	68,013	67,837	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		528	527	436	435	434	433	$2,792
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		107	107	111	111	110	110	$657
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)		$812	$811	$724	$722	$721	$720	$4,509

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 42-8A, pages 49-53.

(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.

(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
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	$50,045	50,222	50,399	50,576	50,752	50,929	51,106	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$67,748	$67,572	$67,395	$67,218	$67,042	$66,865	$66,688	n/a
6.	Average Net Investment		67,660	67,483	67,307	67,130	66,953	66,777	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		432	430	429	428	427	426	5,365
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		110	110	109	109	109	108	1,311
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)		$718	$717	$715	$714	$712	$711	$8,797

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 42-8A, pages 49-53.

(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6840% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.

(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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

Line		Beginning of Period Amount	January 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	$442,037	443,669	445,301	446,934	448,566	450,198	451,831	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$422,224	$420,591	$418,959	$417,327	$415,694	$414,062	$412,430	n/a
6.	Average Net Investment		421,408	419,775	418,143	416,511	414,878	413,246	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		3,238	3,226	2,667	2,657	2,647	2,636	$17,071
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		659	656	679	676	673	671	$4,014
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)		$5,530	$5,514	$4,978	$4,965	$4,952	$4,939	$30,879

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 42-8A, pages 49-53.

(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.

(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
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	$451,831	453,463	455,095	456,728	458,360	459,992	461,625	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$412,430	$410,797	$409,165	$407,533	$405,900	$404,268	$402,636	n/a
6.	Average Net Investment		411,614	409,981	408,349	406,717	405,084	403,452	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		2,626	2,615	2,605	2,594	2,584	2,574	32,669
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		668	665	663	660	657	655	7,982
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)		$4,926	$4,913	$4,900	$4,887	$4,874	$4,861	$60,238

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 42-8A, pages 49-53.
(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	($1,267,288)	$0	$0	($1,267,288)
	c. Retirements		$0	$0	$0	($462,983)	$0	$0	($462,983)
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$2,361,662	2,361,662	2,361,662	2,361,662	1,094,374	1,094,374	1,094,374	n/a
3.	Less: Accumulated Depreciation	$650,566	652,764	654,962	657,160	196,375	198,573	200,771	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,711,096	$1,708,898	$1,706,700	$1,704,502	$897,999	$895,801	$893,603	n/a
6.	Average Net Investment		1,709,997	1,707,799	1,705,601	1,301,250	896,900	894,702	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		13,140	13,123	10,880	8,301	5,721	5,707	$56,872
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		2,674	2,671	2,768	2,112	1,455	1,452	$13,132
8.	Investment Expenses								
	a. Depreciation (E)		2,198	2,198	2,198	2,198	2,198	2,198	$13,188
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$18,012	$17,992	$15,846	$12,610	$9,375	$9,357	$83,193

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 42-8A, pages 49-53.

(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.

(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$368,488	($898,800)
	c. Retirements		$0	$0	$0	$0	$0	$0	($462,983)
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$1,094,374	1,094,374	1,094,374	1,094,374	1,094,374	1,094,374	1,462,862	n/a
3.	Less: Accumulated Depreciation	$200,771	202,969	205,167	207,366	209,564	211,762	214,251	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	*Net Investment (Lines 2 - 3 + 4)*	$893,603	$891,405	$889,207	$887,009	$884,810	$882,612	$1,248,611	n/a
6.	Average Net Investment		892,504	890,306	888,108	885,909	883,711	1,065,611	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		5,693	5,679	5,665	5,651	5,637	6,798	91,996
	b. *Debt Component (Line 6 x debt rate x 1/12) (C)*		1,448	1,445	1,441	1,438	1,434	1,729	22,067
8.	Investment Expenses								
	a. Depreciation (E)		2,198	2,198	2,198	2,198	2,198	2,490	26,669
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$9,340	$9,322	$9,305	$9,287	$9,269	$11,017	$140,732

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 42-8A, pages 49-53.
(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

Return on Capital Investments, Depreciation and Taxes
For Project: 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		$66,693	$0	$0	$0	$0	$0	$66,693
	c. Retirements		$13,582	$0	$0	$0	$0	$0	$13,582
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$286,249	352,942	352,942	352,942	352,942	352,942	352,942	n/a
3.	*Less: Accumulated Depreciation*	($710,488)	(696,376)	(695,847)	(695,317)	(694,788)	(694,258)	(693,729)	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$996,737	$1,049,318	$1,048,789	$1,048,259	$1,047,730	$1,047,201	$1,046,671	n/a
6.	Average Net Investment		1,023,027	1,049,054	1,048,524	1,047,995	1,047,465	1,046,936	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		7,861	8,061	6,689	6,685	6,682	6,678	$42,656
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		1,600	1,641	1,702	1,701	1,700	1,699	$10,042
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)		$9,990	$10,231	$8,919	$8,915	$8,911	$8,907	$55,874

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 42-8A, pages 49-53.

(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.

(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$66,693
	c. Retirements		$0	$0	$0	$0	$0	$0	$13,582
	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	($693,729)	(693,200)	(692,670)	(692,141)	(691,611)	(691,082)	(690,552)	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$1,046,671	$1,046,142	$1,045,612	$1,045,083	$1,044,554	$1,044,024	$1,043,495	n/a
6.	Average Net Investment		1,046,407	1,045,877	1,045,348	1,044,818	1,044,289	1,043,759	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		6,675	6,672	6,668	6,665	6,662	6,658	82,656
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		1,698	1,697	1,696	1,696	1,695	1,694	20,217
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)		$8,903	$8,898	$8,894	$8,890	$8,886	$8,881	$109,226

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 42-8A, pages 49-53.

(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6840% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.

(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

Return on Capital Investments, Depreciation and Taxes
For Project: 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		$3,040,249	$0	$613,024	($2,572,356)	$937	$86,967	$1,168,821
	c. Retirements		$252,578	$0	$0	($295,070)	$0	($219,175)	($261,667)
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$17,691,822	20,732,072	20,732,072	21,345,096	18,772,739	18,773,676	18,860,643	n/a
3.	Less: *Accumulated Depreciation*	$2,695,989	2,984,634	3,020,701	3,057,382	2,799,605	2,836,901	2,655,174	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$14,995,834	$17,747,438	$17,711,371	$18,287,714	$15,973,134	$15,936,776	$16,205,469	n/a
6.	Average Net Investment		16,371,636	17,729,404	17,999,543	17,130,424	15,954,955	16,071,122	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		125,802	136,236	114,819	109,275	101,777	102,518	$690,426
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		25,604	27,727	29,210	27,799	25,892	26,080	$162,311
8.	Investment Expenses								
	a. Depreciation (E)		36,067	36,067	36,680	37,294	37,295	37,448	$220,853
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. *Property Expenses*								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$187,473	$200,030	$180,709	$174,368	$164,964	$166,046	$1,073,591

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 42-8A, pages 49-53.

(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - *Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component* is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.

(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

33

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$10	$79,885	($742)	$116,083	($815)	$291,537	$1,654,778
	c. Retirements		$0	$0	$0	$0	$0	$0	($261,667)
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$18,860,643	18,860,653	18,940,538	18,939,796	19,055,879	19,055,064	19,346,601	n/a
3.	Less: Accumulated Depreciation	$2,655,174	2,692,623	2,730,134	2,767,709	2,805,409	2,843,233	2,881,354	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$16,205,469	$16,168,031	$16,210,404	$16,172,087	$16,250,471	$16,211,830	$16,465,247	n/a
6.	Average Net Investment		16,186,750	16,189,217	16,191,245	16,211,279	16,231,150	16,338,539	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		103,255	103,271	103,284	103,412	103,538	104,224	1,311,410
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		26,268	26,272	26,275	26,308	26,340	26,514	320,288
8.	Investment Expenses								
	a. Depreciation (E)		37,448	37,512	37,574	37,700	37,825	38,120	447,032
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$166,972	$167,055	$167,134	$167,419	$167,703	$168,858	$2,078,731

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 42-8A, pages 49-53.

(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.

(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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

Line		Beginning of Period Amount	January 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	($84,241)	$0	($84,241)
	c. Retirements		$0	$0	$0	$0	($84,241)	$0	($84,241)
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$32,412,763	32,412,763	32,412,763	32,412,763	32,412,763	32,328,522	32,328,522	n/a
3.	Less: Accumulated Depreciation	$4,646,876	4,717,104	4,787,332	4,857,559	4,927,787	4,913,682	4,983,728	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$27,765,887	$27,695,659	$27,625,432	$27,555,204	$27,484,976	$27,414,840	$27,344,795	n/a
6.	Average Net Investment		27,730,773	27,660,545	27,590,318	27,520,090	27,449,908	27,379,817	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		213,088	212,548	175,999	175,551	175,103	174,656	$1,126,944
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		43,368	43,258	44,774	44,660	44,546	44,432	$265,037
8.	Investment Expenses								
	a. Depreciation (E)		70,228	70,228	70,228	70,228	70,136	70,045	$421,092
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$326,684	$326,034	$291,000	$290,438	$289,785	$289,133	$1,813,074

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 42-8A, pages 49-53.
(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	($578,976)	($663,217)
	c. Retirements		$0	$0	$0	$0	$0	($578,976)	($663,217)
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$32,328,522	32,328,522	32,328,522	32,328,522	32,328,522	32,328,522	31,749,547	n/a
3.	Less: Accumulated Depreciation	$4,983,728	5,053,773	5,123,818	5,193,863	5,263,908	5,333,953	4,824,395	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$27,344,795	$27,274,750	$27,204,705	$27,134,659	$27,064,614	$26,994,569	$26,925,151	n/a
6.	Average Net Investment		27,309,772	27,239,727	27,169,682	27,099,637	27,029,592	26,959,860	n/a
7.	Return on Average Net Investment								
	a. *Equity Component grossed up for taxes* (B)		174,209	173,762	173,315	172,869	172,422	171,977	2,165,498
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		44,318	44,205	44,091	43,977	43,864	43,750	529,243
8.	Investment Expenses								
	a. Depreciation (E)		70,045	70,045	70,045	70,045	70,045	69,418	840,736
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$288,572	$288,012	$287,451	$286,891	$286,330	$285,145	$3,535,476

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 42-8A, pages 49-53.
(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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

Line		Beginning of Period Amount	January 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		$373	($7,489)	($3,599)	$0	$0	$0	($10,715)
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$81,911,885	81,912,258	81,904,769	81,901,169	81,901,169	81,901,169	81,901,169	n/a
3.	Less: Accumulated Depreciation	$12,429,925	12,581,762	12,733,593	12,885,413	13,037,230	13,189,046	13,340,863	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$69,481,960	$69,330,495	$69,171,176	$69,015,756	$68,863,940	$68,712,123	$68,560,307	n/a
6.	Average Net Investment		69,406,227.64	69,250,836	69,093,466	68,939,848	68,788,032	68,636,215	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		533,329.09	532,135	440,747	439,767	438,799	437,830	$2,822,608
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		108,544	108,301	112,125	111,876	111,629	111,383	$663,858
8.	Investment Expenses								
	a. Depreciation (E)		151,838	151,831	151,820	151,817	151,817	151,817	$910,938
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$793,710.99	$792,267	$704,692	$703,459	$702,245	$701,030	$4,397,404

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 42-8A, pages 49-53.
(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	($10,715)
	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	$13,340,863	13,492,679	13,644,496	13,796,313	13,948,129	14,099,946	14,251,762	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$68,560,307	$68,408,490	$68,256,673	$68,104,857	$67,953,040	$67,801,224	$67,649,407	n/a
6.	Average Net Investment		68,484,398	68,332,582	68,180,765	68,028,949	67,877,132	67,725,315	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		436,862	435,893	434,925	433,957	432,988	432,020	5,429,252
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		111,136	110,890	110,644	110,397	110,151	109,905	1,326,982
8.	Investment Expenses								
	a. Depreciation (E)		151,817	151,817	151,817	151,817	151,817	151,817	1,821,838
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$699,815	$698,600	$697,385	$696,171	$694,956	$693,741	$8,578,072

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 42-8A, pages 49-53.
(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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

Line		Beginning of Period Amount	January 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)	$492,916	492,916	492,916	492,916	492,916	492,916	492,916	n/a
3.	Less: Accumulated Depreciation	$29,390	30,253	31,115	31,978	32,841	33,703	34,566	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$463,526	$462,664	$461,801	$460,939	$460,076	$459,213	$458,351	n/a
6.	Average Net Investment		463,095	462,232	461,370	460,507	459,645	458,782	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		3,558	3,552	2,943	2,938	2,932	2,927	$18,850
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		724	723	749	747	746	745	$4,434
8.	Investment Expenses								
	a. Depreciation (E)		863	863	863	863	863	863	$5,176
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$5,145	$5,137	$4,554	$4,547	$4,541	$4,534	$28,459

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 42-8A, pages 49-53.
(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

39

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$492,916	492,916	492,916	492,916	492,916	492,916	492,916	n/a
3.	Less: Accumulated Depreciation	$34,566	35,428	36,291	37,154	38,016	38,879	39,741	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$458,351	$457,488	$456,625	$455,763	$454,900	$454,038	$453,175	n/a
6.	Average Net Investment		457,919	457,057	456,194	455,332	454,469	453,606	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		2,921	2,916	2,910	2,905	2,899	2,894	36,294
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		743	742	740	739	738	736	8,871
8.	Investment Expenses								
	a. Depreciation (E)		863	863	863	863	863	863	10,351
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$4,527	$4,520	$4,513	$4,506	$4,499	$4,492	$55,516

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 42-8A, pages 49-53.

(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.

(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$6,282,065	$10,097,772	$15,895,917	$19,857,744	$12,687,777	$10,180,144	$75,001,419
	b. Clearings to Plant		$174,975	$971,863	$24,569,461	$98,423	$18,554,690	$10,761,450	$55,130,861
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$94,243,745	94,418,720	95,390,582	119,960,043	120,058,466	138,613,156	149,374,606	n/a
3.	Less: Accumulated Depreciation	$1,470,706	1,675,173	1,880,882	2,114,259	2,374,360	2,654,669	2,966,737	n/a
4.	CWIP - Non Interest Bearing	$184,908,507	191,190,572	201,288,344	193,581,673	213,439,417	209,825,207	210,049,678	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$277,681,545	$283,934,118	$294,798,044	$311,427,457	$331,123,522	$345,783,694	$356,457,547	n/a
6.	Average Net Investment		280,807,832	289,366,081	303,112,751	321,275,490	338,453,608	351,120,620	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		2,157,774	2,223,537	1,933,556	2,049,416	2,158,995	2,239,798	$12,763,077
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		439,155	452,540	491,891	521,366	549,243	569,799	$3,023,993
8.	Investment Expenses								
	a. Depreciation (E)		204,467	205,709	233,378	260,101	280,309	312,068	$1,496,031
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$2,801,397	$2,881,786	$2,658,825	$2,830,883	$2,988,546	$3,121,664	$17,283,101

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 42-8A, pages 49-53.
(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. *Expenditures/Additions*		$6,659,310	$7,555,695	$5,905,583	$6,675,518	$9,189,939	$13,298,285	$124,285,748
	b. Clearings to Plant		$125,859	$1,737,307	($334,885)	$17,414	($962,144)	$4,755,925	$60,470,336
	c. Retirements		$0	$0	$0	$0	$4,416	$0	$4,416
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$149,374,606	149,500,464	151,237,771	150,902,886	150,920,300	149,958,156	154,714,081	n/a
3.	Less: Accumulated Depreciation	$2,966,737	3,290,599	3,617,025	3,945,527	4,273,698	4,605,472	4,936,729	n/a
4.	CWIP - Non Interest Bearing	$210,049,678	216,708,988	222,591,545	228,497,127	235,172,645	244,362,584	253,353,253	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$356,457,547	$362,918,853	$370,212,291	$375,454,487	$381,819,247	$389,715,268	$403,130,605	n/a
6.	Average Net Investment		359,688,200	366,565,572	372,833,389	378,636,867	385,767,257	396,422,937	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		2,294,451	2,338,321	2,378,304	2,415,324	2,460,809	2,528,781	27,179,067
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		583,702	594,863	605,034	614,452	626,023	643,315	6,691,382
8.	Investment Expenses								
	a. Depreciation (E)		323,862	326,425	328,502	328,171	327,357	331,257	3,461,606
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$3,202,015	$3,259,609	$3,311,840	$3,357,947	$3,414,189	$3,503,353	$37,332,055

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 42-8A, pages 49-53.

(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.

(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$621,436	$3,111,281	$3,063,709	$0	$0	$0	$6,796,426
	b. Clearings to Plant		$0	$0	$0	$97,867,775	$1,717,944	$423,103	$100,008,823
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$0	0	0	0	97,867,775	99,585,719	100,008,823	n/a
3.	Less: Accumulated Depreciation	$0	0	0	0	106,023	319,931	536,159	n/a
4.	CWIP - Non Interest Bearing	$87,481,179	88,102,615	91,213,896	94,277,605	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$87,481,179	$88,102,615	$91,213,896	$94,277,605	$97,761,752	$99,265,788	$99,472,664	n/a
6.	Average Net Investment		87,791,897	89,658,256	92,745,751	96,019,678	98,513,770	99,369,226	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		674,608	688,949	591,625	612,509	628,419	633,876	$3,829,987
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		137,298	140,217	150,508	155,821	159,868	161,256	$904,967
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	106,023	213,908	216,227	$536,159
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$811,905	$829,166	$742,133	$874,354	$1,002,195	$1,011,360	$5,271,113

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 42-8A, pages 49-53.
(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$6,796,426
	b. Clearings to Plant		$1,676,907	$1,003,722	$395,114	$2,295,722	$129,894	$394,871	$105,905,052
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$100,008,823	101,685,729	102,689,452	103,084,565	105,380,287	105,510,181	105,905,052	n/a
3.	Less: Accumulated Depreciation	$536,159	754,661	976,068	1,198,990	1,424,826	1,653,291	1,882,324	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$99,472,664	$100,931,068	$101,713,384	$101,885,576	$103,955,461	$103,856,890	$104,022,728	n/a
6.	Average Net Investment		100,201,866	101,322,226	101,799,480	102,920,518	103,906,175	103,939,809	n/a
7.	Return on Average Net Investment								
	a. *Equity Component grossed up for taxes* (B)		639,188	646,334	649,379	656,530	662,817	663,032	7,747,266
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		162,608	164,426	165,200	167,019	168,619	168,674	1,901,513
8.	Investment Expenses								
	a. Depreciation (E)		218,502	221,406	222,922	225,837	228,465	229,033	1,882,324
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,020,298	$1,032,167	$1,037,501	$1,049,386	$1,059,901	$1,060,739	$11,531,103

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 42-8A, pages 49-53.
(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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

Line	Beginning of Period Amount	January 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)	$235,391	235,391	235,391	235,391	235,391	235,391	235,391	n/a
3. Less: Accumulated Depreciation	$3,767	4,179	4,591	5,003	5,415	5,827	6,239	n/a
4. CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5. Net Investment (Lines 2 - 3 + 4)	$231,624	$231,212	$230,800	$230,388	$229,977	$229,565	$229,153	n/a
6. Average Net Investment		231,418	231,006	230,594	230,183	229,771	229,359	n/a
7. Return on Average Net Investment								
a. Equity Component grossed up for taxes (B)		1,778	1,775	1,471	1,468	1,466	1,463	$9,421
b. Debt Component (Line 6 x debt rate x 1/12) (C)		362	361	374	374	373	372	$2,216
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)		$2,552	$2,548	$2,257	$2,254	$2,251	$2,247	$14,109

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 42-8A, pages 49-53.

(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.

(F) *Applicable amortization period(s). See Form 42-8A, pages 49-53.*

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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

Line	Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1. Investments								
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
c. Retirements		$0	$0	$0	$0	$0	$0	$0
d. Other								
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	$6,239	6,651	7,063	7,474	7,886	8,298	8,710	n/a
4. CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5. Net Investment (Lines 2 - 3 + 4)	$229,153	$228,741	$228,329	$227,917	$227,505	$227,093	$226,681	n/a
6. Average Net Investment		228,947	228,535	228,123	227,711	227,299	226,887	n/a
7. Return on Average Net Investment								
a. Equity Component grossed up for taxes (B)		1,460	1,458	1,455	1,453	1,450	1,447	18,145
b. *Debt Component (Line 6 x debt rate x 1/12)* (C)		372	371	370	370	369	368	4,435
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)*		$2,244	$2,241	$2,237	$2,234	$2,231	$2,227	$27,523

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 42-8A, pages 49-53.

(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.

(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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

Line		Beginning of Period Amount	January 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 42-8A, pages 49-53.

(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.

(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
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 42-8A, pages 49-53.
(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
a.	Expenditures/Additions		$0	$0	$0	$1,524	$6,981	$128	$8,633
b.	Clearings to Plant		$37,722	$27,670	$176,983	($48,277)	$36,246	$237,598	$467,941
c.	Retirements		$0	$0	$0	$0	$0	$0	$0
d.	Other								
2.	Plant-In-Service/Depreciation Base (A)	$150,663,424	150,701,146	150,728,815	150,905,798	150,857,521	150,893,767	151,131,364	n/a
3.	*Less: Accumulated Depreciation & Dismantlement*	$914,894	1,332,356	1,743,844	2,167,720	2,585,785	3,003,890	3,422,379	n/a
4.	CWIP - Non Interest Bearing	$278	278	278	278	1,803	8,783	8,912	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$149,748,808	$149,369,068	$148,985,249	$148,738,356	$148,273,539	$147,898,660	$147,717,897	n/a
6.	Average Net Investment		149,558,938	149,177,159	148,861,803	148,505,947	148,086,099	147,808,279	n/a
a.	Average ITC Balance				43,394,573	43,272,507	43,150,441	43,028,375	
7.	Return on Average Net Investment								
a.	Equity Component grossed up for taxes (B)		1,149,236	1,146,302	1,024,828	1,022,346	1,019,456	1,017,472	$6,379,641
b.	Debt Component (Line 6 x debt rate x 1/12) (C)		233,895	233,298	251,072	250,468	249,760	249,282	$1,467,775
8.	Investment Expenses								
a.	Depreciation (E)		411,403	411,488	411,758	412,006	412,046	412,430	$2,471,131
b.	Amortization (F)								
c.	Dismantlement (G)		6,059	0	12,118	6,059	6,059	6,059	$36,354
d.	Property Expenses								
e.	Amortization ITC Solar		(159,507)	(160,395)	(160,395)	(160,395)	(160,395)	(160,395)	($961,482)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,641,086	$1,630,694	$1,539,381	$1,530,484	$1,526,926	$1,524,849	$9,393,419

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 42-8A, pages 49-53.

(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.

Effective March 2010 equity return associated with solars (after plants are in service) are composed of two parts:
1) Non ITC Average Net investment: Monthly Equity Component of 4.7019%. Note that this will be the rate that will be used to calculate return while unit is in CWIP.
2) Unamortized Average ITC Balance: Monthly Equity Component of 5.98%.
Both pieces reflect a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI. Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%.

(C) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE.

Effective March 2010 return associated with solars (after plants are in service) are composed of two parts:
1) Non ITC Average Net Investment: Monthly Debt Component of 1.9473%. Note that this will be the rate that will be used to calculate return while unit is in CWIP.
2) Unamortized Average ITC Balance: Monthly Debt Component of 2.2100%.
Both pieces reflect a 10% return as approved on FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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

Line			Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments									
	a.	Expenditures/Additions		$134	$2,415	$170	$468	$9,012	$0	$20,831
	b.	Clearings to Plant		$134,335	($2,361)	($2,333)	($1,519)	$1,109	($39,177)	$557,994
	c.	Retirements		$0	$0	$0	$0	$0	$0	$0
	d.	Other								
2.	Plant-In-Service/Depreciation Base (A)		$151,131,364	151,265,699	151,263,338	151,261,004	151,259,486	151,260,595	151,221,418	n/a
3.	Less: Accumulated Depreciation & Dismantlement		$3,422,379	3,841,386	4,260,576	4,679,762	5,098,942	5,519,804	5,939,454	n/a
4.	CWIP - Non Interest Bearing		$8,912	9,045	11,460	11,630	12,097	21,109	21,109	n/a
5.	Net Investment (Lines 2 - 3 + 4)		$147,717,897	$147,433,358	$147,014,221	$146,592,873	$146,172,641	$145,761,900	$145,303,073	n/a
6.	Average Net Investment		147,808,279	147,575,628	147,223,790	146,803,547	146,382,757	145,967,270	145,532,487	n/a
	a.	Average ITC Balance	43,028,375	42,906,309	42,784,243	42,662,177	42,540,111	42,418,045	42,295,979	
7.	Return on Average Net Investment									
	a.	Equity Component grossed up for taxes (B)		1,015,777	1,013,321	1,010,428	1,007,532	1,004,670	1,001,685	12,433,054
	b.	Debt Component (Line 6 x debt rate x 1/12) (C)		248,878	248,280	247,572	246,862	246,161	245,429	2,950,957
8.	Investment Expenses									
	a.	Depreciation (E)		412,949	413,131	413,126	413,122	414,803	413,591	4,951,852
	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)	($1,923,852)
9.	Total System Recoverable Expenses (Lines 7 & 8)			$1,523,267	$1,520,396	$1,516,790	$1,513,180	$1,511,298	$1,506,369	$18,484,719

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 42-8A, pages 49-53.

(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.

Effective March 2010 equity return associated with solars (after plants are in service) are composed of two parts:
1) Non ITC Average Net Investment: Monthly Equity Component of 4.7019%. Note that this will be the rate that will be used to calculate return while unit is in CWIP.
2) Unamortized Average ITC Balance: Monthly Equity Component of 5.98%.
Both pieces reflect a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI. Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%

(C) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE.

Effective March 2010 return associated with solars (after plants are in service) are composed of two parts:
1) Non ITC Average Net investment: Monthly Debt Component of 1.9473%. Note that this will be the rate that will be used to calculate return while unit is in CWIP.
2) Unamortized Average ITC Balance: Monthly Debt Component of 2.2100%.
Both pieces reflect a 10% return as approved on FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.

(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
a.	*Expenditures/Additions*		$9,389,784	$10,938,892	$2,750,130	$0	$0	$0	$23,078,806
b.	Clearings to Plant		$0	$2,565,812	$17,950	$66,990,752	$390,048	$39,778	$70,004,340
c.	Retirements		$0	$0	$0	$0	$0	$0	$0
d.	Other								
2.	Plant-In-Service/Depreciation Base (A)	$0	0	2,565,812	2,583,762	69,574,513	69,964,562	70,004,340	n/a
3.	*Less: Accumulated Depreciation & Dismantlement*	$0	0	2,742	8,239	109,680	304,847	500,701	n/a
4.	CWIP - Non Interest Bearing	$40,526,444	49,916,227	58,378,504	61,128,634	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$40,526,444	$49,916,227	$60,941,574	$63,704,157	$69,464,833	$69,659,714	$69,503,639	n/a
6.	Average Net Investment		45,221,336	55,428,900	62,322,865	66,584,495	69,562,274	69,581,677	n/a
a.	Average ITC Balance						18,389,516	18,325,530	
7.	Return on Average Net Investment								
a.	Equity Component grossed up for taxes (B)		347,488	425,925	397,557	424,742	475,622	475,635	$2,546,970
b.	Debt Component (Line 6 x debt rate x 1/12) (C)		70,722	86,685	101,138	108,053	116,911	116,929	$600,437
8.	Investment Expenses								
a.	Depreciation (E)		0	2,742	5,497	98,530	192,255	192,941	$491,965
b.	Amortization (F)								
c.	Dismantlement (G)		0	0	0	2,912	2,912	2,912	$8,736
d.	Property Expenses								
e.	Amortization ITC Solar		*0*	*0*	*0*	*0*	*(100,893)*	*(87,263)*	($188,156)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$418,210	$515,352	$504,192	$634,237	$686,807	$721,154	$3,479,952

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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 42-8A, pages 49-53.

(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.

Effective March 2010 equity return associated with solars (after plants are in service) are composed of two parts:
1) Non ITC Average Net investment: Monthly Equity Component of 4.7019%. Note that this will be the rate that will be used to calculate return while unit is in CWIP.
2) Unamortized Average ITC Balance: Monthly Equity Component of 5.98%.
Both pieces reflect a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI. Gross-up factor for taxes uses 0.61425, which reflects *the Federal Income Tax Rate of* 35%.

(C) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE.

Effective March 2010 return associated with solars (after plants are in service) are composed of two parts:
1) Non ITC Average Net investment: Monthly Debt Component of 1.9473%. Note that this will be the rate that will be used to calculate return while unit is in CWIP.
2) Unamortized Average ITC Balance: Monthly Debt Component of 2.2100%.
Both pieces reflect a 10% return as approved on FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.

(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
a.	Expenditures/Additions		$0	$0	$0	$0	$0	$0	$23,078,806
b.	Clearings to Plant		$53,345	$17,062	$2,713	$71,548	$6,397	$428,361	$70,583,766
c.	Retirements		$0	$0	$0	$0	$0	$0	$0
d.	Other								
2.	Plant-In-Service/Depreciation Base (A)	$70,004,340	70,057,685	70,074,747	70,077,460	70,149,009	70,155,406	70,583,766	n/a
3.	Less: Accumulated Depreciation & Dismantlement	$500,701	696,686	892,773	1,088,892	1,285,100	1,481,403	1,678,307	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$69,503,639	$69,361,000	$69,181,974	$68,988,569	$68,863,909	$68,674,003	$68,905,459	n/a
6.	Average Net Investment		69,432,320	69,271,487	69,085,271	68,926,239	68,768,956	68,789,731	n/a
a.	*Average ITC Balance*	$18,325,530	18,274,341	18,223,152	18,171,963	18,120,774	18,069,585	18,018,396	
7.	Return on Average Net Investment								
a.	Equity Component grossed up for taxes (B)		474,593	473,478	472,202	471,099	470,007	470,050	5,378,398
b.	*Debt Component (Line 6 x debt rate x 1/12) (C)*		116,675	116,403	116,089	115,820	115,554	115,576	1,296,555
8.	Investment Expenses								
a.	Depreciation (E)		193,073	193,176	193,206	193,296	193,391	193,992	1,652,099
b.	Amortization (F)								
c.	Dismantlement (G)		2,912	2,912	2,912	2,912	2,912	2,912	26,208
d.	Property Expenses								
e.	Amortization ITC Solar		(67,263)	(67,263)	(67,263)	(67,263)	(67,263)	(67,263)	(571,734)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$719,990	$718,706	$717,147	$715,864	$714,600	$715,268	$7,781,526

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 42-8A, pages 49-53.

(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.

Effective March 2010 equity return associated with solars (after plants are in service) are composed of two parts:
1) Non ITC Average Net Investment: Monthly Equity Component of 4.7019%. Note that this will be the rate that will be used to calculate return while unit is in CWIP.
2) Unamortized Average ITC Balance: Monthly Equity Component of 5.98%.
Both pieces reflect a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI. Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%.

(C) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE.

Effective March 2010 return associated with solars (after plants are in service) are composed of two parts:
1) Non ITC Average Net Investment: Monthly Debt Component of 1.9473%. Note that this will be the rate that will be used to calculate return while unit is in CWIP.
2) Unamortized Average ITC Balance: Monthly Debt Component of 2.2100%.
Both pieces reflect a 10% return as approved on FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - *after units are in service.*

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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

Line		Beginning of Period Amount	January Actual	February Actual	March Actual	April Actual	May Actual	June Actual	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$17,906,653	$21,039,816	$13,365,988	$24,478,246	$15,718,721	$17,035,246	$109,544,650
	b. Clearings to Plant		$9	$0	($0)	$0	$0	$0	$9
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$1,318,056	1,318,065	1,318,065	1,318,065	1,318,065	1,318,065	1,318,065	n/a
3.	Less: Accumulated Depreciation & Dismantlement	$17,856	21,671	25,589	29,507	33,425	37,343	41,260	n/a
4.	CWIP - Non Interest Bearing	$189,456,703	207,363,356	228,403,172	241,769,140	266,247,386	281,966,107	299,001,353	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$190,756,902	$208,659,750	$229,695,649	$243,057,699	$267,532,026	$283,246,830	$300,278,158	n/a
6.	Average Net Investment		199,708,326	219,177,699	236,376,674	255,294,863	275,389,428	291,762,494	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		1,534,592	1,684,198	1,507,847	1,628,526	1,756,709	1,861,153	$9,973,024
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		312,324	342,772	383,592	414,293	446,902	473,472	$2,373,355
8.	Investment Expenses								
	a. Depreciation (E)		3,815	3,918	3,918	3,918	3,918	3,918	$23,404
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,850,731	$2,030,888	$1,895,356	$2,046,736	$2,207,529	$2,338,543	$12,369,783

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 42-8A, pages 49-53.*

(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.

Effective March 2010 equity return associated with solars (after plants are in service) are composed of two parts:
1) Non ITC Average Net Investment: Monthly Equity Component of 4.7019%. Note that this will be the rate that will be used to calculate return while unit is in CWIP.
2) Unamortized Average ITC Balance: Monthly Equity Component of 5.98%.
Both pieces reflect a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI. Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%.

(C) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% *ROE.*

Effective March 2010 return associated with solars (after plants are in service) are composed of two parts:
1) Non ITC Average Net Investment: Monthly Debt Component of 1.8473%. Note that this will be the rate that will be used to calculate return while unit is in CWIP.
2) Unamortized Average ITC Balance: Monthly Debt Component of 2.2100%.
Both pieces reflect a 10% return as approved on FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.

(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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

Line			Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments									
	a.	Expenditures/Additions		$19,118,367	$9,205,163	$4,994,750	$5,037,603	$50,039,043	$50,526	$197,990,102
	b.	Clearings to Plant		$21,384	$0	$0	$0	$1,287	$390,784,953	$390,807,633
	c.	Retirements		$0	$0	$0	$0	$0	$0	$0
	d.	Other								
2.	Plant-In-Service/Depreciation Base (A)		$1,318,065	1,339,449	1,339,449	1,339,449	1,339,449	1,340,736	392,125,689	n/a
3.	*Less: Accumulated Depreciation & Dismantlement*		$41,260	46,069	50,344	54,618	58,892	63,168	858,379	n/a
4.	CWIP - Non Interest Bearing		$299,001,353	318,119,720	327,324,883	332,319,633	337,357,236	387,396,279	394,809	n/a
5.	Net Investment (Lines 2 - 3 + 4)		$300,278,158	$319,413,100	$328,613,989	$333,604,465	$338,637,793	$388,673,847	$391,662,119	n/a
6.	Average Net Investment			309,845,629	324,013,545	331,109,227	336,121,129	363,655,820	390,167,983	n/a
	a.	Average ITC Balance	$0	0	0	0	0	0	123,645,277	
7.	Return on Average Net Investment									
	a.	Equity Component grossed up for taxes (B)		1,976,505	2,066,882	2,112,145	2,144,116	2,319,760	2,703,260	23,295,693
	b.	Debt Component (Line 6 x debt rate x 1/12) (C)		502,817	525,809	537,324	545,457	590,141	660,231	5,735,134
8.	Investment Expenses									
	a.	Depreciation (E)		4,809	4,274	4,274	4,274	4,276	766,364	811,675
	b.	Amortization (F)								
	c.	Dismantlement (G)		0	0	0	0	0	28,847	28,847
	d.	Property Expenses								
	e.	Amortization ITC Solar		0	0	0	0	0	(320,597)	(320,597)
9.	Total System Recoverable Expenses (Lines 7 & 8)			$2,484,131	$2,596,965	$2,653,744	$2,693,848	$2,914,176	$3,838,105	$29,550,752

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 42-8A, pages 49-53.

(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.

Effective March 2010 equity return associated with solars (after plants are in service) are composed of two parts:
1) Non ITC Average Net investment: Monthly Equity Component of 4.7019%. Note that this will be the rate that will be used to calculate return while unit is in CWIP.
2) Unamortized Average ITC Balance: Monthly Equity Component of 5.98%.
Both pieces reflect a 10% return on equity per FPSC Order No PSC-10-0153-FOF-EI. Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%.

(C) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE.

Effective March 2010 return associated with solars (after plants are in service) are composed of two parts:
1) Non ITC Average Net investment: Monthly Debt Component of 1.9473%. Note that this will be the rate that will be used to calculate return while unit is in CWIP.
2) Unamortized Average ITC Balance: Monthly Debt Component of 2.2100%.
Both pieces reflect a 10% return as approved on FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.

(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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

Line	Beginning of Period Amount	January 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		($13,324)	$11,125	$27,971	($184)	$31,298	($895)	$55,991
c. Retirements		$0	$0	$0	$0	$0	$0	$0
d. Other								
2. Plant-In-Service/Depreciation Base (A)	$2,986,407	2,973,083	2,984,208	3,012,179	3,011,995	3,043,293	3,042,398	n/a
3. Less: Accumulated Depreciation	$3,868	4,978	6,047	10,961	13,353	15,754	18,168	n/a
4. CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5. Net Investment (Lines 2 - 3 + 4)	$2,982,539	$2,968,106	$2,978,161	$3,001,218	$2,998,641	$3,027,539	$3,024,231	n/a
6. Average Net Investment		2,975,322	2,973,133	2,989,689	2,999,929	3,013,090	3,025,885	n/a
7. Return on Average Net Investment								
a. Equity Component grossed up for taxes (B)		22,863	22,846	19,071	19,137	19,220	19,302	$122,439
b. Debt Component (Line 6 x debt rate x 1/12) (C)		4,653	4,650	4,852	4,868	4,890	4,910	$28,823
8. Investment Expenses								
a. Depreciation (E)		1,109	1,069	4,914	2,392	2,401	2,413	$14,299
b. Amortization (F)								
c. Dismantlement (G)								
d. Property Expenses								
e. Other								
9. Total System Recoverable Expenses (Lines 7 & 8)		$28,625	$28,565	$28,837	$26,397	$26,511	$26,626	$165,561

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 42-8A, pages 49-53.

(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.

(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$2,536	($1,419)	$3,381,577	$362,966	$577,042	$47,752	$4,426,444
	c. Retirements		$0	$0	$0	$0	$659	$0	$659
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$3,042,398	3,044,934	3,043,515	6,425,092	6,788,058	7,365,099	7,412,851	n/a
3.	Less: Accumulated Depreciation	$18,168	20,585	23,001	26,625	31,561	38,136	44,776	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$3,024,231	$3,024,349	$3,020,514	$6,398,467	$6,756,497	$7,326,963	$7,368,075	n/a
6.	Average Net Investment		3,024,290	3,022,431	4,709,490	6,577,482	7,041,730	7,347,519	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		19,292	19,280	30,042	41,958	44,919	46,870	324,800
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		4,908	4,905	7,643	10,674	11,427	11,924	80,303
8.	Investment Expenses								
	a. Depreciation (E)		2,417	2,417	3,623	4,936	5,917	6,640	40,249
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$26,617	$26,601	$41,308	$57,568	$62,263	$65,433	$445,352

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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 42-8A, pages 49-53.

(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.

(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

Return on Capital Investments, Depreciation and Taxes
For Project: 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		$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 42-8A, pages 49-53.

(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.

(D) N/A

(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.

(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.

(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period July through December 2010

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

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		$0	$0	$0	$0	$0	$3,593,541	$3,593,541
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other								
2.	Plant-In-Service/Depreciation Base (A)	$0	0	0	0	0	0	3,593,541	n/a
3.	Less: Accumulated Depreciation	$0	0	0	0	0	0	2,695	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	$3,590,846	n/a
6.	Average Net Investment		0	0	0	0	0	1,795,423	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (B)		0	0	0	0	0	11,453	11,453
	b. Debt Component (Line 6 x debt rate x 1/12) (C)		0	0	0	0	0	2,914	2,914
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	2,695	2,695
	b. Amortization (F)								
	c. Dismantlement (G)								
	d. Property Expenses								
	e. Other								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$17,062	$17,062

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 42-8A, pages 49-53.
(B) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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) Jan & Feb 2010 - Debt component is 1.8767% and reflects an 11.75% ROE. From March 2010 forward the debt component is 1.9473% and reflects a 10% ROE per FPSC Order No PSC-10-0153-FOF-EI.
(D) N/A
(E) Applicable depreciation rate or rates. See Form 42-8A, pages 49-53.
(F) Applicable amortization period(s). See Form 42-8A, pages 49-53.
(G) Dismantlement only applies to Solar projects - DeSoto (37), NASA (38) & Martin (39) - after units are in service.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Period January through June 2010

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

Line		Beginning of Period Amount	January 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	(2,223,838)	(2,209,377)	(2,194,916)	(2,180,455)	(2,214,258)	(2,194,223)	(2,178,860)		
2	Total Working Capital	($2,223,838)	($2,209,377)	($2,194,916)	($2,180,455)	($2,214,258)	($2,194,223)	($2,178,860)		
3	Average Net Working Capital Balance		(2,216,608)	(2,202,147)	(2,187,686)	(2,197,357)	(2,204,240)	(2,186,541)		
4	Return on Average Net Working Capital Balance									
a	Equity Component grossed up for taxes (A)		(17,033)	(16,922)	(13,955)	(14,017)	(14,061)	(13,948)		
b	Debt Component (Line 6 x 1.6698% x 1/12)		(3,467)	(3,444)	(3,550)	(3,566)	(3,577)	(3,548)		
5	Total Return Component		($20,499)	($20,366)	($17,505)	($17,583)	($17,638)	($17,496)	($111,087)	(D)
6	Expense Dr (Cr)									
a	411.800 Gains from Dispositions of Allowances		(14,461)	(14,461)	(14,461)	(36,755)	(20,034)	(24,706)		
b	411.900 Losses from Dispositions of Allowances		0	0	0	0	0	0		
c	509.000 Allowance Expense		0	0	0	0	0	0		
7	Net Expense (Lines 6a+6b+6c)		($14,461)	($14,461)	($14,461)	($36,755)	($20,034)	($24,706)	($124,878)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		(34,960)	(34,826)	(31,966)	(54,338)	(37,672)	(42,202)		
a	Recoverable Costs Allocated to Energy		(34,960)	(34,826)	(31,966)	(54,338)	(37,672)	(42,202)		
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)		(34,270)	(34,139)	(31,336)	(53,266)	(36,929)	(41,369)		
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0		
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($34,270)	($34,139)	($31,336)	($53,266)	($36,929)	($41,369)		

Notes:

(A) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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 2010

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

Line		Beginning of Period Amount	July Actual	August Actual	September Actual	October Actual	November Actual	December Actual	Twelve Month Amount	
1	Working Capital Dr (Cr)									
a	158.100 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0		
b	158.200 Allowances Withheld	$0	0	0	0	0	0	0		
c	182.300 Other Regulatory Assets-Losses	$0	0	0	0	0	0	0		
d	254.900 Other Regulatory Liabilities-Gains	($2,178,860)	(2,158,331)	(2,137,558)	(2,116,786)	(2,096,013)	(2,075,241)	(2,054,468)		
2	Total Working Capital	($2,178,860)	($2,158,331)	($2,137,558)	($2,116,786)	($2,096,013)	($2,075,241)	($2,054,468)		
3	Average Net Working Capital Balance		(2,168,595)	(2,147,944)	(2,127,172)	(2,106,400)	(2,085,627)	(2,064,855)		
4	Return on Average Net Working Capital Balance									
a	Equity Component grossed up for taxes (A)		(13,833)	(13,702)	(13,569)	(13,437)	(13,304)	(13,172)		
b	Debt Component (Line 6 x 1.6698% x 1/12)		(3,519)	(3,486)	(3,452)	(3,418)	(3,385)	(3,351)		
5	Total Return Component		($17,353)	($17,187)	($17,021)	($16,855)	($16,689)	($16,523)	($212,715)	(D)
6	Expense Dr (Cr)									
a	411.800 Gains from Dispositions of Allowances		(20,529)	(20,772)	(20,772)	(20,772)	(20,772)	(20,772)		
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)		($20,529)	($20,772)	($20,772)	($20,772)	($20,772)	($20,772)	($249,269)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		(37,882)	(37,960)	(37,794)	(37,627)	(37,461)	(37,295)		
a	Recoverable Costs Allocated to Energy		(37,882)	(37,960)	(37,794)	(37,627)	(37,461)	(37,295)		
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)		(37,134)	(37,211)	(37,048)	(36,885)	(36,722)	(36,559)		
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0		
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($37,134)	($37,211)	($37,048)	($36,885)	($36,722)	($36,559)		

Notes:

(A) Jan & Feb 2010 - The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 5.6640% reflects an 11.75% return on equity.
March 2010 forward, the 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
2010 Annual Capital Depreciation Schedule

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Actual Balance December 2009	Actual Balance December 2010
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	Riviera U3	31200	0.00%	3,815,802.70	0.00
	02 - Steam Generation Plant	Riviera U4	31200	0.00%	3,246,925.80	0.00
	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					16,959,531.40	9,896,802.90
03 - Continuous Emission Monitoring						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	0.00%	59,227.10	0.00
	02 - Steam Generation Plant	CapeCanaveral Comm	31200	0.00%	44,644.65	0.00
	02 - Steam Generation Plant	CapeCanaveral U1	31200	0.00%	325,165.05	0.00
	02 - Steam Generation Plant	CapeCanaveral U2	31200	0.00%	345,150.96	0.00
	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%	462,142.42	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	Riviera Comm	31100	0.00%	60,973.18	0.00
	02 - Steam Generation Plant	Riviera Comm	31200	0.00%	11,495.25	0.00
	02 - Steam Generation Plant	Riviera U3	31200	0.00%	453,591.63	0.00
	02 - Steam Generation Plant	Riviera U4	31200	0.00%	437,621.87	0.00
	02 - Steam Generation Plant	Sanford U3	31100	1.90%	54,282.08	54,282.08
	02 - Steam Generation Plant	Sanford U3	31200	2.40%	425,269.85	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%	23,694.18	23,619.18
	05 - Other Generation Plant	FtMyers U3 CC	34300	5.20%	0.00	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%	4,688.46	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%	330,765.69	346,616.08
	05 - Other Generation Plant	Putnam U2	34300	3.30%	364,509.68	380,355.07
	05 - Other Generation Plant	Sanford U4	34300	4.80%	80,349.32	98,339.95
	05 - Other Generation Plant	Sanford U5	34300	4.20%	38,489.84	56,521.05
03 - Continuous Emission Monitoring Total					11,866,572.48	10,232,475.17

Florida Power & Light Company
Environmental Cost Recovery Clause
2010 Annual Capital Depreciation Schedule

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Actual Balance December 2009	Actual Balance December 2010
04 - Clean Closure Equivalency Demonstration						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	0.00%	17,254.20	0.00
	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					**58,865.78**	**41,611.58**
05 - Maintenance of Above Ground Fuel Tanks						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	0.00%	901,636.88	0.00
	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	31200	2.60%	104,845.35	104,845.35
	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	Riviera Comm	31100	0.00%	1,081,354.77	0.00
	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%	68,893.65	140,654.89
	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					**13,644,546.70**	**11,733,316.29**
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	71,937.99	86,360.48
	02 - Steam Generation Plant	Amortizable	31670	7-Year	317,984.82	364,984.05
	02 - Steam Generation Plant	Martin Comm	31600	2.40%	23,107.32	23,107.32
	02 - Steam Generation Plant	PtEverglades Comm	31600	2.10%	1,961.85	0.00
	05 - Other Generation Plant	Amortizable	34650	5-Year	23,258.48	22,458.48
	05 - Other Generation Plant	Amortizable	34670	7-Year	45,699.54	43,232.74
	08 - General Plant	Amortizable	39190	3-Year	1,943.47	0.00
08 - Oil Spill Clean-up/Response Equipment Total					**485,893.47**	**540,143.07**
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%	706,500.94	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%	296,707.34	665,195.32
	02 - Steam Generation Plant	Riviera Comm	31100	0.00%	560,786.81	0.00
20 - Wastewater/Stormwater Discharge Elimination Total					**2,361,661.78**	**1,462,862.01**
21 - St. Lucie Turtle Nets						
	03 - Nuclear Generation Plant	StLucie Comm	32100	1.80%	286,248.99	352,942.34
21 - St. Lucie Turtle Nets Total					**286,248.99**	**352,942.34**

Florida Power & Light Company
Environmental Cost Recovery Clause
2010 Annual Capital Depreciation Schedule

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Actual Balance December 2009	Actual Balance December 2010
23 - Spill Prevention Clean-Up & Countermeasures						
	02 - Steam Generation Plant	CapeCanaveral Comm	31100	0.00%	689,323.23	0.00
	02 - Steam Generation Plant	CapeCanaveral Comm	31400	0.00%	13,451.85	0.00
	02 - Steam Generation Plant	CapeCanaveral Comm	31500	0.00%	33,805.48	0.00
	02 - Steam Generation Plant	Cutler Comm	31400	1.90%	12,236.00	12,236.00
	02 - Steam Generation Plant	Cutler U5	31400	1.90%	18,388.00	18,388.00
	02 - Steam Generation Plant	Manatee Comm	31100	2.10%	749,862.61	749,862.61
	02 - Steam Generation Plant	Manatee Comm	31200	2.60%	0.00	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%	0.00	45,749.52
	02 - Steam Generation Plant	Manatee U2	31200	2.60%	0.00	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%	10,379.00	2,967,754.07
	02 - Steam Generation Plant	PtEverglades Comm	31200	2.30%	0.00	159,113.30
	02 - Steam Generation Plant	PtEverglades Comm	31500	2.00%	7,782.85	7,782.85
	02 - Steam Generation Plant	Riviera Comm	31100	0.00%	205,014.03	0.00
	02 - Steam Generation Plant	Riviera U3	31200	0.00%	736,958.97	0.00
	02 - Steam Generation Plant	Riviera U4	31200	0.00%	894,298.77	0.00
	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 U1	32300	2.40%	404,835.79	1,019,294.68
	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%	1,703,610.61	1,836,482.98
	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	1,713,191.94
	05 - Other Generation Plant	Putnam Comm	34500	2.50%	60,746.93	60,746.93
	06 - Transmission Plant - Electric		35200	1.90%	951,562.91	1,042,156.83
	06 - Transmission Plant - Electric		35300	2.60%	177,981.88	177,981.88
	07 - Distribution Plant - Electric		36100	1.90%	2,862,093.44	2,931,887.67
	08 - General Plant		39000	2.10%	12,843.35	99,812.99
23 - Spill Prevention Clean-Up & Countermeasures Total					17,691,822.42	19,346,600.86
24 - Manatee Reburn						
	02 - Steam Generation Plant	Manatee U1	31200	2.60%	16,771,308.37	16,687,067.37
	02 - Steam Generation Plant	Manatee U2	31200	2.60%	15,641,455.08	15,062,479.29
24 - Manatee Reburn Total					32,412,763.45	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%	20,657,216.45	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					81,911,884.65	81,901,169.49
26 - UST Remove/Replace						
	08 - General Plant		39000	2.10%	492,916.42	492,916.42
26 - UST Remove/Replace Total					492,916.42	492,916.42

Florida Power & Light Company
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Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Actual Balance December 2009	Actual Balance December 2010
31 - Clean Air Interstate Rule (CAIR)						
	02 - Steam Generation Plant	Manatee Comm	31100	2.10%	97,886.91	102,052.47
	02 - Steam Generation Plant	Manatee U1	31200	2.60%	0.00	19,794,254.26
	02 - Steam Generation Plant	Manatee U1	31400	2.60%	277,326.13	6,219,701.47
	02 - Steam Generation Plant	Manatee U2	31200	2.60%	12,968,660.92	13,163,149.00
	02 - Steam Generation Plant	Manatee U2	31400	2.60%	6,958,582.62	7,918,302.41
	02 - Steam Generation Plant	Martin Comm	31400	2.60%	103,606.27	287,257.77
	02 - Steam Generation Plant	Martin U1	31200	2.60%	10,165,745.01	14,651,505.23
	02 - Steam Generation Plant	Martin U1	31400	2.60%	7,694,692.34	7,694,692.34
	02 - Steam Generation Plant	Martin U2	31200	2.60%	0.00	20,683,349.06
	02 - Steam Generation Plant	Martin U2	31400	2.60%	0.00	7,385,556.36
	02 - Steam Generation Plant	SJRPP U1	31200	2.60%	28,457,245.91	28,172,582.67
	02 - Steam Generation Plant	SJRPP U2	31200	2.60%	27,244,027.25	27,066,114.22
	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%	0.00	762,997.86
	05 - Other Generation Plant	Martin Comm	34300	4.30%	0.00	244,230.62
	05 - Other Generation Plant	Martin Comm	34500	3.40%	0.00	292,363.70
	05 - Other Generation Plant	PtEverglades GTs	34300	3.40%	107,874.44	107,874.44
31 - Clean Air Interstate Rule (CAIR) Total					94,243,744.56	154,714,080.64
33 - Clean Air Mercury Rule (CAMR)						
	02 - Steam Generation Plant	Scherer U4	31200	2.60%	0.00	105,905,052.28
33 - Clean Air Mercury Rule (CAMR) Total					0.00	105,905,052.28
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
37 - DeSoto Solar Energy Center						
	05 - Other Generation Plant	Amortizable	34630	3-Year	8,397.00	12,102.91
	05 - Other Generation Plant	Amortizable	34650	5-Year	11,335.44	21,934.62
	05 - Other Generation Plant	Amortizable	34670	7-Year	47,579.36	50,094.94
	05 - Other Generation Plant	DeSoto Solar	34000	0.00%	255,507.00	255,507.00
	05 - Other Generation Plant	DeSoto Solar	34100	3.30%	3,001,233.05	3,249,119.87
	05 - Other Generation Plant	DeSoto Solar	34300	3.30%	141,414,275.84	141,636,734.40
	06 - Transmission Plant - Electric		35200	1.90%	2,556.04	2,603.27
	06 - Transmission Plant - Electric		35300	2.60%	361,701.33	797,283.55
	06 - Transmission Plant - Electric		35310	2.90%	0.00	1,712,305.00
	06 - Transmission Plant - Electric		35500	3.40%	390,927.39	394,417.57
	06 - Transmission Plant - Electric		35600	3.20%	170,961.23	191,357.87
	07 - Distribution Plant - Electric		36100	1.90%	605,133.72	608,237.66
	07 - Distribution Plant - Electric		36200	2.60%	4,343,249.97	2,238,948.26
	08 - General Plant		39220	9.40%	28,426.16	28,426.16
	08 - General Plant	Amortizable	39720	7-Year	22,140.36	22,344.95
37 - DeSoto Solar Energy Center Total					150,663,423.89	151,221,418.03
38 - Spacecoast Solar Energy Center						
	01 - Intangible Plant	Amortizable	30300	30-Year	0.00	6,359,027.00
	05 - Other Generation Plant	Amortizable	34630	3-Year	0.00	7,271.71
	05 - Other Generation Plant	Amortizable	34650	5-Year	0.00	9,438.49
	05 - Other Generation Plant	Amortizable	34670	7-Year	0.00	37,454.78
	05 - Other Generation Plant	Spacecoast Solar	34100	3.30%	0.00	1,208,355.56
	05 - Other Generation Plant	Spacecoast Solar	34300	3.30%	0.00	60,328,241.78
	06 - Transmission Plant - Electric		35300	2.60%	0.00	139,390.84
	07 - Distribution Plant - Electric		36100	1.90%	0.00	269,763.87
	07 - Distribution Plant - Electric		36200	2.60%	0.00	2,186,607.33
	08 - General Plant		39220	9.40%	0.00	31,858.14
	08 - General Plant	Amortizable	39720	7-Year	0.00	6,356.95
38 - Spacecoast Solar Energy Center Total					0.00	70,583,766.45

Florida Power & Light Company
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2010 Annual Capital Depreciation Schedule

Project	Function	Site/Unit	Account	Depreciation Rate / Amortization Period	Actual Balance December 2009	Actual Balance December 2010
39 - Martin Solar Energy Center						
	05 - Other Generation Plant	Amortizable	34650	5-Year	0.00	21,384.00
	05 - Other Generation Plant	Martin Solar	34000	0.00%	0.00	216,844.31
	05 - Other Generation Plant	Martin Solar	34100	3.30%	0.00	90.55
	05 - Other Generation Plant	Martin Solar	34300	3.30%	0.00	390,586,865.63
	05 - Other Generation Plant	Martin Solar	34600	3.30%	0.00	1,152.33
	05 - Other Generation Plant	Martin U8	34300	4.30%	320,325.05	300,334.49
	06 - Transmission Plant - Electric		35500	3.40%	0.00	618,700.98
	06 - Transmission Plant - Electric		35600	3.20%	987,006.51	368,305.53
	07 - Distribution Plant - Electric		36400	4.10%	9,282.42	9,282.42
	07 - Distribution Plant - Electric		36760	2.60%	1,441.83	2,728.36
39 - Martin Solar Energy Center Total					1,318,055.81	392,125,688.60
41 - Manatee Heaters						
	02 - Steam Generation Plant	CapeCanaveral Comm	31400	0.70%	0.00	3,502,299.42
	02 - Steam Generation Plant	Riviera Comm	31400	0.60%	2,529,005.40	2,605,268.34
	06 - Transmission Plant - Electric		35300	2.60%	300,558.82	282,951.11
	07 - Distribution Plant - Electric		36100	1.90%	0.00	9,669.19
	07 - Distribution Plant - Electric		36200	2.60%	0.00	322,202.56
	07 - Distribution Plant - Electric		36400	4.10%	60,129.11	186,148.51
	07 - Distribution Plant - Electric		36500	3.90%	70,260.27	271,244.89
	07 - Distribution Plant - Electric		36660	1.50%	917.90	119,589.43
	07 - Distribution Plant - Electric		36760	2.60%	25,535.54	105,249.65
	07 - Distribution Plant - Electric		36910	3.90%	0.00	607.49
	08 - General Plant	Amortizable	39720	7-Year	0.00	7,620.86
41 - Manatee Heaters Total					2,986,407.04	7,412,851.45
42 - Turkey Point Cooling Canal Monitoring						
	03 - Nuclear Generation Plant	TurkeyPt Comm	32100	1.80%	0.00	3,593,540.81
42 - Turkey Point Cooling Canal Monitoring Total					0.00	3,593,540.81
Grand Total					428,632,814.41	1,054,555,260.62

FLORIDA POWER & LIGHT COMPANY					
ENVIRONMENTAL COST RECOVERY CLAUSE					
Equity @ 11.75%	CAPITAL STRUCTURE AND COST RATES PER 12/31/2006 SURVEILLANCE REPORT (a)				
					PRE-TAX
	ADJUSTED		MIDPOINT	WEIGHTED	WEIGHTED
	RETAIL	RATIO	COST RATES	COST	COST
LONG TERM DEBT	3,486,292,100	26.413%	5.539%	1.4630%	1.4630%
SHORT TERM DEBT	643,567,393	4.876%	4.576%	0.2231%	0.2231%
PREFERRED STOCK	0	0.000%	0.000%	0.0000%	0.0000%
CUSTOMER DEPOSITS	406,209,278	3.077%	5.963%	0.1835%	0.1835%
COMMON EQUITY	6,331,842,680	47.971%	11.750%	5.6366%	9.1763%
DEFERRED INCOME TAX	2,283,698,536	17.302%	0.000%	0.0000%	0.0000%
INVESTMENT TAX CREDITS					
ZERO COST	0	0.000%	0.000%	0.0000%	0.0000%
WEIGHTED COST	47,778,535	0.362%	9.545%	0.0345%	0.0518%
TOTAL	$13,199,388,522	100.00%		7.541%	11.10%

CALCULATION OF THE WEIGHTED COST FOR INVESTMENT TAX CREDITS					
	ADJUSTED		COST	WEIGHTED	
	RETAIL	RATIO	RATE	COST	
LONG TERM DEBT	$3,486,292,100	35.51%	5.54%	1.97%	1.97%
PREFERRED STOCK	0	0.00%	0.00%	0.00%	0.00%
COMMON EQUITY	6,331,842,680	64.49%	11.75%	7.58%	12.34%
TOTAL	$9,818,134,780	100.00%		9.54%	14.30%
RATIO					0.36%
					0.05%
DEBT COMPONENTS:					
LONG TERM DEBT	1.4630%				
SHORT TERM DEBT	0.2231%				
CUSTOMER DEPOSITS	0.1835%				
TAX CREDITS -WEIGHTED	0.0071%				
TOTAL DEBT	1.8767%				
EQUITY COMPONENTS:					
PREFERRED STOCK	0.0000%				
COMMON EQUITY	5.6366%				
TAX CREDITS -WEIGHTED	0.0274%				
TOTAL EQUITY	5.6640%				
TOTAL	7.5407%				
PRE-TAX EQUITY	9.2210%				
PRE-TAX TOTAL	11.0977%				

Note:

(a) In 2005, FPL filed a base rate increase request using a 2006 test year in Docket 050045-EI which ended in a settlement agreement that was approved by the Commission in Order No. PSC-05-0902-EI. FPL calculated the clause rate of return using the actual 2006 capital structure and costs from the December Surveillance Report updated for the 11.75% common equity cost rate stipulated to in the docket Settlement Agreement. The above capital structure remained in place for the entire settlement period which ended Feb 28, 2010.

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

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

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REVISED 8-26-11

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

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

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

Form 42-4E

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	28,957	26,729	10,168	20,542	132,535
	26 UST Replacement/Removal	0	0	0	0	0	0	0
	27 Lowest Quality Water Source	26,276	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	6,108	4,201	36,328
	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	$ 1,074,836	$ 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.

8

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	$ 91,561	$ 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	866,057			866,057
	5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	346,989	8,650	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	61,500	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	176,266	127,323	152,755	816,256	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	178,200	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	$ 6,158,815	$ 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)

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Form 42-7E
Page 1 of 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.

REVISED 8-26-11
Form 42-7E

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	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	4,033,086	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.

21

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.

22

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.

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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: 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: 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	($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.

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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: 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.

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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: 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.

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.

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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: 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.

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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: 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.

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.

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.

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.

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	7,616,101	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	938	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.

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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
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**

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

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI EXHIBIT 5
PARTY FLORIDA POWER& LIGHT CO. (DIRECT)
DESCRIPTION T. J. KEITH (TJK-3)
DATE 11/01/11

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)	14,199,493	11,133,178	2,539,598	27,872,269
	b Projected Capital Projects (FORM 42-3P, Page 2 of 2, Lines 7 through 9)	23,373,637	136,768,754	0	160,142,391
	c Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b)	37,573,130	147,901,932	2,539,598	188,014,660
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 October 5, 2011)	1,739,122	6,840,663	128,888	8,708,673
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)	34,659,513	137,242,148	2,367,900	174,269,561
5	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier 1.00072)	34,684,468	137,340,962	2,369,605	174,395,035

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	29,432	2,875	0	0	41,453
2	Total of O&M Activities	$2,370,093	$2,161,839	$2,376,379	$2,120,443	$2,067,687	$1,797,089	$12,893,532
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	$627,543	$661,206	$720,430	$607,905	$3,941,674
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	$615,079	$648,074	$706,122	$595,832	$3,863,391
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	$2,336,268	$2,085,221	$2,032,093	$1,765,037	$12,673,178

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

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	0	0	0	0	0	0	0			0
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	0	0	0	0	0	0	0	41,453	41,453		
2 Total of O&M Activities	$1,837,592	$2,022,469	$1,859,533	$2,100,121	$2,378,666	$5,283,727	$15,482,106	$28,375,637	$11,358,768	$2,539,598	$14,477,271
3 Recoverable Costs Allocated to Energy	$1,124,416	$1,002,301	$1,049,701	$1,017,874	$1,486,179	$1,392,385	$7,072,856	$14,477,271			
4a Recoverable Costs Allocated to CP Demand	$565,269	$872,261	$661,924	$909,339	$674,865	$3,733,435	$7,417,094	$11,358,768			
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	$983,069	$1,029,561	$998,344	$1,457,664	$1,365,669	$6,937,148	$14,199,493			
8a Jurisdictional CP Demand Recoverable Costs (B)	$554,043	$854,938	$648,778	$891,279	$661,462	$3,659,287	$7,269,787	$11,133,178			
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)	$1,804,791	$1,985,914	$1,826,246	$2,062,530	$2,336,747	$5,182,863	$15,199,091	$27,872,269			

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

Totals may not add due to rounding.

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

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line #	Project #	Description	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	0	0	0	0	0	0	0
2		Total Investment Projects - Recoverable Costs	$13,024,702	$13,015,803	$13,027,884	$13,438,438	$13,847,431	$13,868,964	$80,223,220
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	$11,078,903	$11,072,277	$11,085,017	$11,465,577	$11,842,366	$11,861,504	$68,405,644
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)	$10,858,871	$10,852,377	$10,864,863	$11,237,866	$11,607,171	$11,625,929	$67,047,077
9		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$12,767,335	$12,758,612	$12,770,452	$13,172,873	$13,573,764	$13,594,871	$78,637,907

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	Method of Classification 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	0	0	0	0	0	0	0	0	0	
2	Total Investment Projects - Recoverable Costs	$13,877,009	$13,865,601	$13,857,278	$13,851,010	$13,840,559	$13,856,293	$83,147,749	$163,370,970	$139,540,082	$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	$ 11,870,527	$ 11,861,591	$ 11,855,504	$ 11,849,883	$ 11,840,405	$ 11,856,530	$ 71,134,440	$ 139,540,082		
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)	$ 11,634,773	$11,626,014	$11,620,048	$11,614,539	$11,605,249	$11,621,054	$69,721,677	$136,768,754		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$13,602,756	$13,591,572	$13,583,414	$13,577,270	$13,567,026	$13,582,446	$81,504,484	$160,142,391		

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.

8

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.

6

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.

11

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.

12

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.

13

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.

14

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.

15

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.

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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: 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.

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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: 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.

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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: 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.

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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: 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.

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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: 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.

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.

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.

37

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.

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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: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).

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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: 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.

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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: 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	266,610
	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.

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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: 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		$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 42-4P, 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: 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		$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 42-4P, 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**

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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**

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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**

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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**

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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 (SO2), nitrogen oxides (NOx) and particulate matter. The fee covers units in FPL's service area, as well as Unit 4 of Plant Scherer located in Juliette, Georgia, within the Georgia Power Company service area. FPL's share of ownership of that unit is 76.36%. The fees for FPL's units are paid to the Florida Department of Environmental Protection (FDEP) generally in February of each year, whereas FPL pays its share of the fees for Scherer Unit 4 to Georgia Power Company on a monthly basis.

Project Accomplishments:
(January 1, 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.

Form 42-6P

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.

REVISED 10-18-11
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%	$18,706,818	$85,735,667	$1,400,976	$105,843,461	55,179,030,324	0.00192
GS1/GST1	5.31359%	4.67834%	5.08365%	$1,842,991	$6,425,277	$120,462	$8,388,730	5,436,225,128	0.00154
GSD1/GSDT1/HLTF(21-499 kW)	23.26687%	19.74926%	20.52940%	$8,069,991	$27,123,819	$486,466	$35,680,276	23,806,124,732	0.00150
OS2	0.01176%	0.00491%	0.04572%	$4,079	$6,744	$1,083	$11,906	12,458,252	0.00096
GSLD1/GSLDT1/CS1/CST1/HLTF(500-1,999 kW)	10.15434%	8.67939%	9.42633%	$3,521,977	$11,920,354	$223,367	$15,665,698	10,401,423,229	0.00151
GSLD2/GSLDT2/CS2/CST2/HLTF(2,000+ kW)	2.13756%	1.51193%	1.65121%	$741,402	$2,076,499	$39,127	$2,857,028	2,211,649,384	0.00129
GSLD3/GSLDT3/CS3/CST3	0.20383%	0.14437%	0.17243%	$70,699	$198,274	$4,086	$273,059	218,123,888	0.00125
ISST1D	0.00000%	0.00000%	0.00000%	$0	$0	$0	$0	0	0.00098
ISST1T	0.00000%	0.00000%	0.00000%	$0	$0	$0	$0	0	0.00171
SST1T	0.09391%	0.09832%	0.19311%	$32,574	$135,029	$4,576	$172,179	100,498,031	0.00171
SST1D1/SST1D2/SST1D3	0.00687%	0.00328%	0.00860%	$2,381	$4,510	$204	$7,095	7,272,632	0.00098
CILC D/CILC G	2.90401%	1.81478%	2.06840%	$1,007,239	$2,492,442	$49,013	$3,548,694	3,006,093,828	0.00118
CILC T	1.24495%	0.76233%	0.87060%	$431,805	$1,046,985	$20,630	$1,499,420	1,332,228,131	0.00113
MET	0.07523%	0.06888%	0.07576%	$26,093	$94,601	$1,795	$122,489	79,693,587	0.00154
OL1/SL1/PL1	0.57586%	0.00769%	0.70524%	$199,733	$10,555	$16,711	$226,999	589,146,032	0.00039
SL2, GSCU1	0.07694%	0.05112%	0.04678%	$26,686	$70,205	$1,108	$97,999	78,713,822	0.00125
TOTAL				$34,684,468	$137,340,962	$2,369,605	$174,395,035	102,458,681,000	0.00170

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).

FLORIDA POWER & LIGHT COMPANY

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION
INDUSTRIAL WASTEWATER FACILITY PERMIT NO. FL0002208
ST. LUCIE PLANT

RRL-1
DOCKET NO. 110007-EI
EXHIBIT ____________
PAGES 1-9

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI EXHIBIT 6
PARTY FLORIDA POWER & LIGHT CO. (DIRECT)
DESCRIPTION R. R. LABAUVE (RRL-1)
DATE 11/01/11

Florida Department of Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

NOTICE OF PERMIT

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

In the Matter of an
Application for Permit by:

Florida Power & Light
Mr. Richard L. Anderson
Vice President
6501 S. Ocean Dr
Jensen Beach, Florida 34957

St. Lucie County
St. Lucie Plant
NPDES Permit No. FL0002208

Enclosed is Permit FL0002208, issued under Section 403.0885, Florida Statutes, and DEP Chapter 62-620, Florida Administrative Code, authorizing an increase in the permitted temperature limitation, from 113 to 115°F, for the heated cooling water within the discharge canal at the St. Lucie Plant Units 1 and 2. The St. Lucie Plant is located at 6501 S. Ocean Dr., Jensen Beach, Florida 34957 in St. Lucie County.

Any party to this order (permit) has the right to seek judicial review of the permit under Section 120.68, Florida Statutes, by the filing of a Notice of Appeal under Rules 9.110 and 9.190, Florida Rules of Appellate Procedure, with the Clerk of the Department of Environmental Protection, Office of General Counsel, Mail Station 35, 3900 Commonwealth Boulevard, Tallahassee, Florida 32399-3000 and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate district court of appeal. The notice of appeal must be filed within thirty days after this notice is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Janet G. Llewellyn
Director
Division of Water Resource Management

2600 Blair Stone Road
Tallahassee, FL 32399-2400
(850) 245-8336

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF PERMIT and all copies were mailed before the close of business on 12 - 21 - 2010 to the listed persons.

[Clerk Stamp]

FILING AND ACKNOWLEDGMENT

FILED, on this date, under Section 120.52 (9), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Shirley Shields 12-21-2010
(Clerk) (Date)

Copies furnished to:

Copies furnished by certified mail to:
Chief, NPDES Permitting Section, EPA Region 4, Atlanta, GA
Chairman, Board of St. Lucie County Commissioners
Ron Hix, FPL

Copies furnished by intradepartmental mail to:
Mike Halpin, P.E., DEP Tallahassee
Justin Wolfe, Esq., DEP Tallahassee
Linda Brien, P.G., DEP West Palm Beach
Michael Hambor, DEP West Palm Beach

STATE OF FLORIDA
INDUSTRIAL WASTEWATER FACILITY PERMIT

Additions to the permit are identified by *italics* and underline. Deletions are identified by ~~strikethrough~~.

PERMITTEE:	**PERMIT NUMBER:**	FL0002208 (Major) (Rev. F)
	PA FILE NUMBER:	FL0002208-003-IW1S
FPL - St. Lucie Power Plant	**ISSUANCE DATE:**	January 20, 2006
6501 S. Ocean Drive	**REVISION DATE:**	December 23, 2010
Jensen Beach, FL 34957	**EXPIRATION DATE:**	January 19, 2011

RESPONSIBLE AUTHORITY:

Richard L. Anderson
Vice President

FACILITY:

St. Lucie Power Plant
Units 1 and 2
Hutchinson Island
St. Lucie County, Florida

Latitude: See Note Below Longitude: See Note Below

Note: Latitude and longitude are not shown at the Permittee's request, for purposes of Homeland Security pursuant to federal regulations found at 18 CFR 388.113(c)(i) and (ii) and by Presidential Directive dated December 17, 2003.

This permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.) and applicable rules of the Florida Administrative Code (F.A.C.). *Compliance with Administrative Order AO022TL is a specific requirement of this permit.* The above named Permittee is hereby authorized to operate the facilities shown on the application and other documents attached hereto or on file with the Department and made a part hereof and specifically described as follows:

The facility consists of two nuclear powered steam electric generating units (Unit 1 and Unit 2) each with a nominal rating of 953 MW. The radioactive component of the discharge is regulated by the U.S. Nuclear Regulatory Commission under the Atomic Energy Act, and not by the Department or the U.S. Environmental Protection Agency under the Clean Water Act.

WASTEWATER TREATMENT:

Facility discharge and treatment include the following. Once-through non-contact condenser cooling water (OTCW) and auxiliary equipment cooling water (AECW) are chlorinated. Low volume waste (LVW) (consisting of water treatment system wastewater, steam generator/boiler blowdown, and equipment area floor drainage), non-radioactive wastes/liquid radiation waste, and stormwater associated with industrial activity are treated by chemical/physical processes including neutralization, settling, ion exchange and micro filtration. Non-industrial stormwater and intake screen wash water are discharged without treatment.

PERMITTEE:		PERMIT NUMBER:	FL0002208 (Rev. F)
		Revision date	December 23, 2010
FPL - St. Lucie Power Plant		Issuance date:	January 20, 2006
6451 S. Ocean Dr.		Expiration date:	January 19, 2011
Jensen Beach, FL34957			

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EFFLUENT DISPOSAL:

Surface Water Discharge:

An existing discharge (1487 MGD permitted maximum daily flow, 1,362 reported annual average daily flow) of OTCW and AECW via outfall D-001 to the onsite discharge canal to the point of discharge (POD) thence to the Atlantic Ocean, a Class III marine water.

Internal Outfalls:

Existing intermittent discharges from internal outfalls I-003 (Liquid Radiation Waste), I-005 (Steam Generator Blowdown), I-007 (Intake Screen Wash Water) and I-008 (Evaporation/Percolation Basin).

Stormwater Discharges:

Existing intermittent stormwater discharges from internal outfalls I-06B (Former Oil Storage Area) and I-06C (Non-Industrial Related Stormwater) and I-06D (Spent Nuclear Fuel Dry Storage Area) to the intake canal via an outlet control structure. Discharge from I-06D will intermittently include wash-down water consisting of potable water with no additives.

IN ACCORDANCE WITH: The limitations, monitoring requirements and other conditions as set forth in Part I through Part VIII on pages 3 through 18 of this permit.

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I. Effluent Limitations and Monitoring Requirements

A. Surface Water Discharges

1. During the period beginning on the issuance date and lasting through the expiration date of this permit, the Permittee is authorized to discharge via Outfall D-001 (OTCW and AECW from Units 1 and 2). Such discharge shall be limited and monitored by the Permittee as specified below:

	Discharge Limitations		Monitoring Requirements		
Parameters (units)	Daily Average	Instantaneous Maximum	Monitoring Frequency	Sample Type	Sample Point
Flow (MGD)	--	Report	Hourly	Pump logs	FLW-1
Discharge Temperature Water *During Normal Operation* (DEG. F)	--	See Cond. I.A.3. and I.A.4.	Hourly	Recorder	EFF-2
Discharge Temperature Water During Maintenance Activities (DEG. F)	*--*	*117* *See Cond. I.A.3. and I.A.4.*	*Hourly*	*Recorder*	*EFF-2*
Temp. Diff. Between Intake and Discharge *During Normal Operation* (DEG.F)	--	30 See Cond. I.A.3. and I.A.4.	Hourly	Calculated	INT-1, EFF-2
Temp. Diff. Between Intake and Discharge During Maintenance Activities (DEG.F)	*--*	*32* *See Cond. I.A.3. and I.A.4.*	*Hourly*	*Calculated*	*INT-1, EFF-2*
Oxidants, Total Residual (MG/L)	--	0.10 See Cond. I.A.7.	Continuous	Recorder See Cond. I.A.5.	EFF-2
Oxidants, Free Available (MG/L)	0.2 See Cond. I.A.7.	0.5 See Cond. I.A.7.	Every Other Month	Multiple Grabs See Cond. I.A.6.	EFF-1
Chlorination Duration (Minutes)	120, See Cond. I.A.7.		Daily	Logs	EFF-1
Whole Effluent Toxicity (Acute)	See Cond. I.A.8.				EFF-2

2. Effluent samples shall be taken at the monitoring site locations listed in permit condition I.A.1 and as described below:

Sample Point	Description of Monitoring Location
FLW-1	Pump log or recorder
INT-1	At plant intake structure within the intake canal

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Sample Point	Description of Monitoring Location
EFF-1	Outlet corresponding to the individual condenser from Unit 1 or Unit 2
EFF-2	Within the discharge canal upstream of the discharge piping to the Atlantic Ocean

3. At ~~the point of discharge~~ *monitoring location EFF-2*, the heated water temperature ~~from the diffusers~~ shall not exceed 113°F, before notification to the Department for power uprate completion for Units 1 and 2, *or 115°F, after notification to the Department for power uprate completion for Units 1 and 2,* ~~or~~ *and* 30°F above ambient at any time except that the maximum discharge temperature shall be limited to 117°F ~~or~~ *and* 32°F above ambient during ~~condenser or~~ circulating water system maintenance~~, throttling circulating water pumps to minimize use of chlorine, or fouling of circulating water system~~. *The ambient* temperature may be measured at a point within the ~~discharge~~ *intake* canal until installation *of thermometer(s) in accordance with Administrative Order AO022TL*. In determining the temperature differential, the time of travel through the plant may be considered. The permittee shall submit with the Discharge Monitoring Report a summary of cooling water system maintenance activities and associated maximum discharge temperature reading and temperature difference above ambient. In the event that discharge temperature exceeds ~~113°F~~ *the temperature limitations*, the Permittee shall notify the Department within 5 days.

   Circulating water system maintenance (including, but not limited to, condenser and / or circulating water pump maintenance) shall mean:
   a. *repair or scheduled preventive activities that maintain the facility's circulating water system and its support systems within its as-designed capacity; and*
   b. *results in at least one circulating water pump being shut down, or equivalent loss of heat removal, on each unit being shut down.*

4. Discharge from Outfall D-001 shall not cause the ocean surface temperature to exceed 97°F as an instantaneous maximum at any point. Heated water discharged from the multi-port diffuser shall not exceed 17 °F above ambient temperature in the receiving body of water outside a thermal mixing zone of 10.7 acre-feet (13,198 cubic meters, 466,092 cubic feet). The mixing zone shall be bounded by an area extending 1,385.5 feet seaward from the most landward discharge port, 21.0 feet to each side of the discharge pipe axis and 8.0 feet in height above the bottom of the discharge. Heated water discharged from the Y-diffuser shall not exceed 17° F above ambient temperature in the receiving body of water outside a thermal mixing zone bounded by a circle with a radius of 115.82 meters, centered on the terminus of the Y-Port diffuser and extending upward from the bottom 8.31 meters, encompassing a mixing zone that shall not exceed 453,613 square feet (42,142 square meters). The total area of the thermal mixing zone for the facility (multi-port and Y-port diffusers) shall not exceed 511,804 square feet (47,548 square meters).

5. If automated TRO monitors are inoperable for more than 7 days, TRO monitoring shall be conducted at least one time per week on not less than three grab samples during daylight hours. Additional grab samples shall be obtained during periods of TRO discharge from condensers.

6. A "multiple grab" sample for FAO from Outfall D-001 for FAO/TRO monitoring shall consist of individual grab samples collected at the approximate beginning of FAO/TRO discharge and once every 15 minutes thereafter until the end of FAO/TRO discharge.

7. Free available oxidants (FAO) shall not exceed an average concentration of 0.2 mg/l and a maximum instantaneous concentration of 0.5 mg/l at the outlet corresponding to an individual condenser during any chlorination period. Additionally, TRO shall not exceed a maximum instantaneous concentration of 0.10 mg/l at any one time as measured at the POD prior to discharge to the Atlantic Ocean. Auxiliary equipment cooling water may receive continuous low-level chlorination. Neither FAO nor total residual oxidants (TRO) may be

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME:	Florida Power and Light (FPL)	PERMIT NUMBER:	FL0002208-004-IWB		
MAILING ADDRESS:	6501 S Ocean Dr Jensen Beach, Florida 34957-2041				
		LIMIT:	Interim (Pre-Uprate)	REPORT FREQUENCY:	Monthly
		CLASS SIZE:	MA	PROGRAM:	Industrial
FACILITY:	St. Lucie Power Plant	MONITORING GROUP NUMBER:	D-001		
LOCATION:	6501 S Ocean Dr. Jensen Beach, FL 34957	MONITORING GROUP DESCRIPTION:	OTCW and AECW from Units 1 and 2		
		RE-SUBMITTED DMR: ☐			
		NO DISCHARGE FROM SITE: ☐			
COUNTY:	St. Lucie	MONITORING PERIOD From:	______	To:	______
OFFICE:	Southeast District				

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Flow	Sample Measurement										
PARM Code 50050 1 Mon. Site No. FLW-1	Permit Requirement		Report (Inst.Max.)	MGD						Hourly	Pump Logs
Temperature (F), Water (During Normal Operation)	Sample Measurement										
PARM Code 00011 1 Mon. Site No. EFF-2	Permit Requirement						113 (Inst.Max.)	Deg F		Hourly	Meter
Temperature (F), Water (During Maintenance Activities)	Sample Measurement										
PARM Code 00011 Q Mon. Site No. EFF-2	Permit Requirement						117 (Inst.Max.)	Deg F		Hourly	Meter
Temperature (F), Water	Sample Measurement										
PARM Code 00011 R Mon. Site No. INT-1	Permit Requirement						Report (Inst.Max.)	Deg F		Hourly	Meter
Temp. Diff. between Intake and Discharge (During Normal Operations)	Sample Measurement										
PARM Code 61576 1 Mon. Site No. INT-1, EFF-2	Permit Requirement						30 (Inst.Max.)	Deg F		Hourly	Calculated
Temp. Diff. between Intake and Discharge (During Maintenance Activities)	Sample Measurement										
PARM Code 61576 Q Mon. Site No. INT-1, EFF-2	Permit Requirement						32 (Inst.Max.)	Deg F		Hourly	Calculated
Oxidants, Total Residual	Sample Measurement										
PARM Code 34044 1 Mon. Site No. EFF-2	Permit Requirement						0.10 (Inst.Max.)	mg/L		Continuous	Meter

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

ISSUANCE/REISSUANCE DATE:

DEP Form 62-620.910(10), Effective Nov. 29, 1994

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME:	Florida Power and Light (FPL)	PERMIT NUMBER:	FL0002208-004-IWB				
MAILING ADDRESS:	6501 S Ocean Dr Jensen Beach, Florida 34957-2041						
		LIMIT:	Final (Post-Uprate)	REPORT FREQUENCY:	Monthly		
		CLASS SIZE:	MA	PROGRAM:	Industrial		
FACILITY:	St. Lucie Power Plant	MONITORING GROUP NUMBER:	D-001				
LOCATION:	6501 S Ocean Dr. Jensen Beach, FL 34957	MONITORING GROUP DESCRIPTION:	OTCW and AECW from Units 1 and 2				
		RE-SUBMITTED DMR:	☐				
		NO DISCHARGE FROM SITE:	☐				
COUNTY:	St. Lucie	MONITORING PERIOD From:	________	To:	________		
OFFICE:	Southeast District						

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Flow	Sample Measurement										
PARM Code 50050 1 Mon. Site No. FLW-1	Permit Requirement		Report (Inst.Max.)	MGD						Hourly	Pump Logs
Temperature (F), Water (During Normal Operation)	Sample Measurement										
PARM Code 00011 1 Mon. Site No. EFF-2	Permit Requirement						115 (Inst.Max.)	Deg F		Hourly	Meter
Temperature (F), Water (During Maintenance Activities)	Sample Measurement										
PARM Code 00011 Q Mon. Site No. EFF-2	Permit Requirement						117 (Inst.Max.)	Deg F		Hourly	Meter
Temperature (F), Water	Sample Measurement										
PARM Code 00011 R Mon. Site No. INT-1	Permit Requirement						Report (Inst.Max.)	Deg F		Hourly	Meter
Temp. Diff. between Intake and Discharge (During Normal Operations)	Sample Measurement										
PARM Code 61576 1 Mon. Site No. INT-1, EFF-2	Permit Requirement						30 (Inst.Max.)	Deg F		Hourly	Calculated
Temp. Diff. between Intake and Discharge (During Maintenance Activities)	Sample Measurement										
PARM Code 61576 Q Mon. Site No. INT-1, EFF-2	Permit Requirement						32 (Inst.Max.)	Deg F		Hourly	Calculated
Oxidants, Total Residual	Sample Measurement										
PARM Code 34044 1 Mon. Site No. EFF-2	Permit Requirement						0.10 (Inst.Max.)	mg/L		Continuous	Meter

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

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ISSUANCE/REISSUANCE DATE:

DEP Form 62-620.910(10), Effective Nov. 29, 1994

FLORIDA POWER & LIGHT COMPANY

FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION
ADMINISTRATIVE ORDER NO. AO022TL
ST. LUCIE POWER PLANT

RRL-2
DOCKET NO. 110007-EI
EXHIBIT ____________
PAGES 1-8

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI **EXHIBIT** 7
PARTY FLORIDA POWER & LIGHT CO. (DIRECT)
DESCRIPTION R. R. LABAUVE (RRL-2)
DATE 11/01/11

BEFORE THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

IN THE MATTER OF:

Florida Power and Light, Inc.
6501 S. Ocean Drive
Jensen Beach, Florida 34957

Administrative Order No. AO022TL

St. Lucie Power Plant
DEP Permit No: FL0002208

ADMINISTRATIVE ORDER

I. STATUTORY AUTHORITY

The Department of Environmental Protection (Department) issues this Administrative Order under the authority of Section 403.088(2)(f), Florida Statutes (F.S.). The Secretary of the Department has delegated this authority to the Director of the Division of Water Resources Management, who issues this order and makes the following findings of fact.

II. FINDINGS OF FACT

1. Florida Power and Light (FPL or Permittee) is a "person" as defined under Section 403.031(5), F.S.
2. The Permittee owns and operates a nuclear steam electric power generating facility known as St. Lucie power plant ("Facility"). The Facility, located at 6501 S. Ocean Drive, Jensen Beach St. Lucie County, Florida 34957, discharges industrial wastewater into waters of the state as defined in Section 403.031(13), F.S.
3. The Permittee has filed an application for revision of NPDES Permit No. FL0002208 (Permit), under Section 403.088(2), F.S.
4. The Permit expires on January 19, 2011. The Permittee has applied for renewal of the Permit 180 days before the expiration date. Hence, the Department may administratively continue the Permit, if necessary, after the expiration date of the Permit pursuant to Rules 62-620.335(1)-(4), F.A.C.
5. The Permittee is planning to increase the generating capacity of its two existing nuclear units (Units 1 and 2) at the Facility by an additional 106 megawatts each. Known in the industry as a "power uprate," this effort entails modifying or replacing existing plant components such as the turbine generators, valves and certain control systems to increase electric generation capacity.
6. Units 1 and 2 use once-through cooling water from the Atlantic Ocean to remove heat from the main condensers via a circulating water system. The condensers are located in each unit's secondary system, where steam is cooled to liquid water before being returned to the steam generators to complete the secondary loop. Cooling water is pumped from the Atlantic Ocean through three offshore intake structures into the plant's intake canal. This water is then pumped through the main condensers for each unit. Heated cooling water is released to the onsite discharge canal and then to open waters, as defined in Rule 62-302.520(3)(f), F.A.C., of the Atlantic Ocean through existing offshore pipes and diffusers.
7. After the power uprate is completed, the cooling water flow rate will remain unchanged; however, using thermodynamic models, the temperature in the discharge canal is predicted to increase by 2°F under normal operating conditions. The modeling effort indicates that the heated water released to

the Atlantic Ocean meets the surface temperature and adjacent coastal water requirements in Rule 62-302.520(4)(c), F.A.C., and the thermal mixing zone requirements in the existing Permit.

8. The Permittee anticipates commencing commercial operation of the repowered nuclear units sequentially in December 2011 (Unit 1) and July 2012 (Unit 2).

9. Rule 62-302.520(6)(a), F.A.C., authorizes the Department to establish mixing zones for thermal discharges from once-through cooling water systems, on a case-by-case bases, when supported by a demonstration, as provided in Section 316(a) of the Clean Water Act and regulations promulgated thereunder, including Title 40 of the Code of Federal Regulations (40 CFR) Parts 122 and 125, that assures the protection and propagation of a balanced, indigenous population of shellfish, fish and wildlife in and on the body of water.

10. Under 40 CFR Section 125.73, existing sources can base their 316(a) demonstration on a lack of appreciable harm instead of completing predictive studies. However, under 40 CFR Section 125.72(c), the type of detailed studies contemplated under 125.72(a) and (b) can be required whenever the Department determines it to be necessary. The Permittee collected a substantial amount of biological data in support of its 316(a) demonstration from the mid 1970's to early 1980's. After examining the record of prior 316(a) determinations for the Facility after those dates, the Department has determined that a need exists for a more thorough examination of the balanced, indigenous population, the identification of representative important species, and a closer examination of whether the temperature limitations are protective.

11. Sections 403.088(2)(e) and (f), F.S., allow the Department to issue, renew, or reissue a permit for the discharge of wastewater into waters of the state, which may not immediately meet all applicable rule requirements, if the permit is accompanied by an order establishing a schedule for achieving compliance with all permit conditions if criteria specified in the order are met.

12. The Department finds that the granting of an operation permit will be in the public interest; and,

13. This order and associated wastewater Permit FL0002208 constitute the Department's authorization to discharge pollutants to waters of the state under the NPDES and its determination that the Facility is in compliance with Section 403.088, F.S. This order includes an implementation schedule.

III. ORDER

Based on the foregoing findings of fact,

IT IS ORDERED,

14. No later than 90 days after the effective date of this Order, the Permittee shall prepare and submit for the Department's review and approval a feasibility study report (Ambient Monitoring Report) for 1) the identification and evaluation of potential locations in the Atlantic Ocean that are near the Facility's ocean intake structure and meet the requirements of Rule 62-302.520(3)(a), F.A.C., for permanently siting remote thermometers; and 2) the evaluation of commercially available remote thermometers. Each option, which shall consist of a location and a thermometer, shall be ranked based on equal weighting of technical and economic feasibility. The results of the ranking shall be presented in the Ambient Monitoring Report. In addition, the Ambient Monitoring Report shall include a plan and schedule for implementing the highest ranked option. The schedule shall include milestones and the completion date. The implementation shall take no longer than 18 months from the effective date of this Order.

15. No later than 30 days after installing the new thermometer(s), the Permittee shall provide a certification to the Department, signed and sealed by a licensed Professional Engineer, that the thermometer(s) have been properly installed and calibrated.

16. Until the Permittee has installed and calibrated new thermometer(s) for ambient temperature monitoring, the Permittee shall calculate the temperature rise above ambient at Outfall D-001 by subtracting the temperature measured at INT-1 from that measured at EFF-2. Monitoring locations INT-1 and EFF-2 are defined in condition I.A.2 of Permit No. FL0002208.

17. No later than 180 days after the effective date of this Order, the Permittee shall prepare and submit for the Department's review and approval a plan of study (Heated Water POS) and schedule to confirm the results of the mathematical model used for simulating the near and far field extent of the Facility's heated water discharge. The Heated Water POS shall be designed and implemented to demonstrate that the heated water discharge from the Facility: 1) does not raise the surface temperature near the Facility's open ocean outfalls to more than 97°F; and 2) does not heat adjacent coastal waters more than the limitations specified in Rule 62-302.520(4)(b), F.A.C. This study also shall evaluate whether and to what extent the heated water discharge raises the cooling water entering the Facility above ambient temperature. The study shall commence no later than 90 days after completion of both uprate projects for Unit 1 and 2. The study shall last no less than 24 months from commencement. The results of the study shall be submitted in a report (Heated Water Report) to the Department for review and approval no later than 60 days after the approved Heated Water POS completion date. The schedule shall include milestones and the completion date.

18. If the Heated Water Report fails to demonstrate that the heated water discharge from the Facility meets the discharge limitations in Part III.17 of this Order, the Permittee shall prepare a feasibility study report (Engineering Report) for the evaluation of engineering options to achieve the discharge limitations. The Engineering Report shall be submitted to the Department for review and approval no later than 180 days after after any Department determination that heated water from the discharge fails to meet the discharge limitations in Part III.17 of the Order. The options shall be ranked based on equal weighting of technical and economic feasibility. The results of the ranking shall be presented in the Engineering Report. In addition, the Engineering Report shall include a plan and schedule for implementing the highest ranked option. The schedule shall include milestones and the completion date. The implementation shall take no longer than 24 months from Department approval.

19. The Permittee shall provide a status report demonstrating progress toward compliance with the discharge limitation every six months following the approval of the Engineering Report, until compliance is achieved pursuant to Section I.A. of the Permit. The status reports shall document accomplishment of milestones established by the schedule in the approved Engineering Report.

20. No later than 90 days after the effective date of this Order, the Permittee shall prepare and submit for the Department's review and approval a biological plan of study (Biological POS) and schedule. Biological POS shall be designed to generate information relevant to the following elements: 1) "a population typically characterized by diversity at all trophic levels;" 2) "the capacity to sustain itself through cyclic seasonal changes;" 3) "presence of necessary food chain species;" 4) "non-domination of pollution-tolerant species;" and 5) "indigenous." Each of these elements is discussed in more detail in Paragraphs III. 21-25 of this Order. In addition to the foregoing elements, the Biological POS shall also include provisions for the identification of Representative Important Species (e.g., a list of threatened, endangered, thermally sensitive, or commercially or recreationally valuable species in up- and down-stream of the study area). Representative Important Species is defined as "species which are representative, in terms of their biological needs, of a balanced, indigenous community of shellfish, fish and wildlife in the body of water into which a discharge of heat is made." The study shall collect data pre- and post-completion of the uprate of Units 1 and 2 and shall last no less than 24 months after completion of the uprate. The results of the study shall be submitted in a report

(Biological Report) to the Department for review and approval no later than 90 days after the approved Biological POS completion date. The schedule shall include milestones and the completion date.

21. "A population typically characterized by diversity at all tropic levels" means that all of the major tropic levels present in the unaffected portion of the Atlantic Ocean should be present in the heat affected portions. The Department recognizes that community structure differences will occur, however, the number of species represented in each tropic level in the unaffected portions should be reasonably similar in the heat affected portions of the ocean. Sampling and analysis of fish and invertebrate communities should be done such that the major tropic levels are identified and represented by reasonably similar species distributions. Also, the Biological POS shall be expanded to include some observations of wildlife (i.e., water fowl, mammals, amphibians, etc.) both upstream and immediately downstream of the discharge point that may be impacted by the thermal discharge.

22. "The capacity to sustain itself through cyclic seasonal changes" means that any additional thermal stress will not cause significant community instability during times of natural extremes in environmental conditions. Community data shall be collected during normal seasonal extremes as well as during optimal seasonal conditions. Data shall be compared between heat affected and unaffected portions of the ocean to account for normal community changes corresponding with change in season.

23. "Presence of necessary food chain species" means that the necessary food webs remain intact so that communities will be sustaining. Exhaustive food web studies are not necessary provided that planktonic invertebrate, fish and wildlife communities are otherwise healthy, i.e., represented by sufficiently high species diversity and abundance (appropriate for that portion of the ocean) for the identified tropic levels and sustaining through normal seasonal changes.

24. "Non-domination of pollution-tolerant species" means that in the case of a thermal effluent, community assemblages in heat affected portions of the ocean dominated by heat tolerant species do not constitute a balanced, indigenous population. The Department recognizes that because all species have varying levels of thermal tolerance, communities in the heat affected portions of the ocean may possess altered assemblages in terms of species present and abundance. All community data should be collected, analyzed and presented to clearly demonstrate that affected communities have not shifted to primarily heat tolerant assemblages.

25. "Indigenous" means a community that may include historically non-native species introduced in connection with a program of wildlife management and species whose presence or abundance results from substantial, irreversible environmental modifications. Normally, however, such a community will not include species whose presence is attributable to the introduction of pollutants that will be eliminated by compliance by all sources with Section 301(b)(2) of the Clean Water Act, and may not include species whose presence or abundance is attributable to alternative effluent limitations imposed pursuant to a thermal zone of mixing . The Department recognizes that non-indigenous species are present in aquatic systems in Florida. All community data shall be analyzed and presented to demonstrate that community assemblages in the heat affected portions of the ocean are not significantly different from non-affected communities with regard to the number of non-indigenous species in the assemblages.

26. If the Biological Report fails to demonstrate that a balanced, indigenous population exists based on the criteria listed in Paragraphs III.16 of this Order, the Permittee shall prepare a feasibility study report (Report) for the evaluation of options to achieve a balanced, indigenous population. The Report shall be submitted to the Department for review and approval no later than 90 days after after any Department determination that heated water from the discharge fails to meet the discharge limitations in Part III.20 of the Order. The options shall be ranked based on equal weighting of

technical and economic feasibility. The results of the ranking shall be presented in the Report. In addition, the Report shall include a plan and schedule for implementing the highest ranked option. The schedule shall include milestones and the completion date. The implementation shall take no longer than 24 months from Department approval of the Report.

27. The Permittee shall provide a status report demonstrating progress toward a balanced, indigenous population every six months following the approval of the Report, until a balanced, indigenous population is achieved. The status reports shall document accomplishment of milestones established by the schedule in the approved Report.

28. Monitoring results shall be submitted in accordance with the Permit.

29. The Permittee shall maintain and operate its facilities in compliance with all other conditions of the Permit.

30. This Order may be modified through revisions as set forth in Chapter 62-620, F.A.C. Unless otherwise specified herein, reports or other information required by this order shall be sent to: Industrial Wastewater Section, ATTN: Mail Station 3545, Department of Environmental Protection, 2600 Blair Stone Road, Tallahassee, Florida 32399-2400, with a copies sent to: Industrial Wastewater Section, Department of Environmental Protection, Southeast District, 1801 SE Hillmoor Drive, Suite C-204, Port St. Lucie, Florida 34952 and Industrial Wastewater Section, Department of Environmental Protection, Southeast District, 400 N. Congress Avenue, Suite A,West Palm Beach, Florida 33416.

31. This order does not operate as a permit under Section 403.088, F.S. This order shall be incorporated by reference into NPDES Permit No. FL0002208, which shall require compliance by the Permittee with the requirements of this order.

32. Failure to comply with the requirements of this order shall constitute a violation of this order and Permit No. FL0002208, and may subject the Permittee to penalties as provided in Section 403.161, F.S.

33. This order is final when filed with the clerk of the Department, and the Permittee then shall implement this order unless a petition for an administrative proceeding (hearing) is filed in accordance with the notice set forth in the following Section.

34. If any event occurs that causes delay or the reasonable likelihood of delay, in complying with the requirements of this order, the Permittee shall have the burden of demonstrating that the delay was or will be caused by circumstances beyond the reasonable control of the Permittee and could not have been or cannot be overcome by the Permittee's due diligence. Economic circumstances shall not be considered circumstances beyond the reasonable control of the Permittee, nor shall the failure of a contractor, subcontractor, materialman or other agent (collectively referred to as "contractor") to whom responsibility for performance is delegated to meet contractually imposed deadlines be a cause beyond the control of the Permittee, unless the cause of the contractor's late performance was also beyond the contractor's control. Delays in final agency action on an application for a relief mechanism are eligible for consideration under this paragraph, provided that none of those delays were a result of late submission by the Permittee. Upon occurrence of an event causing delay, or upon becoming aware of a potential for delay, the Permittee shall notify the Department orally at: the Department's Southeast District office, (772) 871-7662, within 24 hours or by the next working day and shall, within seven calendar days of oral notification to the Department, notify the Department in writing at: with a copies sent to: Industrial Wastewater Section, Department of Environmental Protection, Southeast District, 1801 SE Hillmoor Drive, Suite C-204, Port St. Lucie, Florida 34952 of the anticipated length and cause of the delay, the measures taken or to be taken to prevent or minimize the delay and the timetable by which Facility intends to implement these measures. If the

delay or anticipated delay has been or will be caused by circumstances beyond the reasonable control of the Permittee, the time for performance hereunder shall be extended for a period equal to the delay resulting from such circumstances.

IV. NOTICE OF RIGHTS

A person whose substantial interests are affected by the Department's decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57 of the F.S. The petition must contain the information set forth below and must be filed (received by the clerk) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000.

Petitions by the applicant or any of the parties listed below must be filed within twenty-one days of receipt of this written notice. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within twenty-one days of publication of the notice or within twenty-one days of receipt of the written notice, whichever occurs first.

Under Section 120.60(3), F.S., however, any person who has asked the Department for notice of agency action may file a petition within twenty-one days of receipt of such notice, regardless of the date of publication.

The petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S. Any subsequent intervention (in a proceeding initiated by another party) will be only at the discretion of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Department's action is based must contain the following information:

(a) The name, address, and telephone number of each petitioner; the Department permit identification number and the county in which the subject matter or activity is located;

(b) A statement of how and when each petitioner received notice of the Department action;

(c) A statement of how each petitioner's substantial interests are affected by the Department action;

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

(e) A statement of facts that the petitioner contends warrant reversal or modification of the Department action;

(f) A statement of which rules or statutes the petitioner contends require reversal or modification of the Department action; and

(g) A statement of the relief sought by the petitioner, stating precisely the action that the petitioner wants the Department to take.

A petition that does not dispute the material facts on which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation under Section 120.573, F.S., is not available for this proceeding.

This action is final and effective on the date filed with the Clerk of the Department unless a petition is filed in accordance with the above. Upon the timely filing of a petition this order will not be effective until further order of the Department.

Any party to the order has the right to seek judicial review of the order under Section 120.68, F.S., by the filing of a notice of appeal under rule 9.110 of the Florida Rules of Appellate Procedure with the Clerk of the Department in the Office of General Counsel, Mail Station 35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000; and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate district court of appeal. The notice of appeal must be filed within 30 days from the date when the final order is filed with the Clerk of the Department.

DONE AND ORDERED on this 17th day of DEC. 2010 in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Janet G. Llewellyn

Janet G. Llewellyn
Director
Division of Water Resource Management

CLERK STAMP

FILED AND ACKNOWLEDGED on this date, under Section 120.52(7) of the Florida Statutes, with the designated Department Clerk, receipt of which is acknowledged.

Clerk

Date

Copies furnished to Permit Distribution List

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 110007-EI EXHIBIT 8

PARTY FLORIDA POWER & LIGHT CO. (DIRECT)

DESCRIPTION R. R. LABAUVE (RRL-3)

DATE 11/01/11

FLORIDA POWER & LIGHT COMPANY
DOCKET NO. 110007-EI
ENVIRONMENTAL COST RECOVERY CLAUSE
FPL SUPPLEMENTAL CAIR/CAMR/CAVR FILING
APRIL 1, 2011

Per Order No. PSC-11-0083-FOF-EI, issued on January 31, 2011, the discussion below provides FPL's current estimates of project activities and associated costs related to its Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR) and Clean Air Visibility Rule (CAVR)/ Best Available Retrofit Technology (BART) Projects.

CAIR Compliance Project Update:

St. Johns River Power Park (SJRPP) Selective Catalytic Reduction Systems (SCR) and Ammonia Injection Systems – The construction and installation of SCR and Ammonia Injection Systems on SJRPP was accomplished in 2009 with the controls on both units being placed into service in 2010. The total CAIR capital cost for installation of the SCR and Ammonia Injection System for FPL's ownership share of SJRPP is $55.3 million.

Estimated CAIR O&M expenses for 2011 are $1.405 million and estimated annual O&M expenses beginning 2012 are approximately $1.165 million (FPL 20% ownership). Ongoing O&M activities for the SCR include incremental operating staff, ammonia consumption, maintenance of the SCR ammonia injection skid and SCR auxiliary equipment.

Scherer SCR and Wet Flue Gas Desulfurization (FGD) - Current capital cost estimates for the installation of the FGD, Scrubber and SCR with Ammonia Injection System on Scherer Unit 4 is $369.2 million. The construction of plant infrastructure required for the reagent supply has been completed and waste by-product removal from the emission controls being implemented at Plant Scherer is currently underway and FPL's share of the costs for those facilities needed for support of Unit 4 are included in the project costs. Unit specific engineering and design work on the FGD and SCR for Unit 4 was completed in 2008 and procurement of materials needed for the construction of the equipment began in 2009. Construction is currently underway as foundation work for the FGD and SCR and the foundation for the new chimney for output from the FGD were completed in 2008.

Project work accomplished in 2009 included: delivery and initial installation of SCR structural steel; delivery and installation of SCR ammonia storage facility; initial construction of FGD chimney liner and absorber foundation activities; Scherer common FGD facility work including limestone handling prep equipment, tanks, piping, and electrical; and initial construction activities for FGD gypsum waste disposal facility. The 2010 project work included the erection of the scrubber vessel and stack/liner. Unanticipated, persistent inclement weather increased the original planned construction schedule. Project work in 2010 also included the SCR support structure and Unit 4 FGD absorber vessel. Additionally, construction was substantially completed in 2010 for SCR and FGD project common facilities (e.g., unloading and storage facilities for ammonia and limestone and limestone grinding facilities). FPL estimates its share of the Scherer Unit 4 CAIR capital costs to be $97.4 million in 2011 and $29.4 million in 2012. FPL has preliminarily estimated annual O&M for operation of the SCR, FGD, and common plant facilities supporting the controls at $3.5 million for 2012 when the FGD and SCR are projected to be in-service. O&M activities for the SCR include incremental operating staff, ammonia consumption, maintenance of the SCR ammonia injection skid and SCR auxiliary equipment. O&M activities for the FGD include limestone consumption, limestone and by-product handling operation, FGD operations, FGD tower and auxiliary equipment maintenance.

800 MW unit cycling project – Mr. LaBauve introduced this project in his September 1, 2006 testimony and subsequently provided an estimate for implementation of the projects with a total capital cost of $104.8 million. FPL had originally planned completion of the 800 MW unit cycling project in 2010 at the Martin and Manatee Plants utilizing existing planned outage windows to complete project work. As a result of changes to the Manatee Unit 2 outage schedule to accommodate system load requirements, completion of remaining boiler and associated drain work was postponed to 2011. Project work completed at the Martin and Manatee Plants for 2010 included major boiler, turbine and balance of plant initiatives.

800 MW unit cycling project total capital costs to date are $113.6 million and total O&M expenses to date are $3.6 million. There are six remaining tasks for the completion of the 800 MW cycling project. Planned work for 2011 includes the Super Heat (SH) Spray Upgrade, Extraction Control/Mass Blowdown on Manatee Unit 2, and the implementation of rotor stress monitors on all four 800 MW units. FPL plans to complete the remaining boiler work at Manatee Unit 2 during a planned fall 2011 outage. For 2011, FPL projects a capital cost of $1.6 million and an O&M expense of $500 thousand. FPL plans to complete the project work at the Manatee and Martin plants in 2011 with an estimated total project cost of $115.2 million in capital costs and $4.1 million in O&M expenses. Decreases to the capital project costs from the prior estimate are primarily the result of lower than originally projected costs for the rotor stress monitors. Increases to the O&M expenses were primarily a result of reclassification of project removal work from capital to O&M.

Rule Challenge – On July 11, 2008 the United States Circuit Court of Appeals for the District of Columbia (the Court) issued an opinion vacating the United States Environmental Protection Agency's (EPA) CAIR. On December 23, 2008, the Court issued an opinion on rehearing of the July 11 decision and remanded CAIR to the EPA without vacatur, instructing EPA to remedy the CAIR flaws in accordance with the Court's July 11 opinion. This results in CAIR remaining in effect in its current form until it is revised for the July 11 opinion. On September 23, 2009, FPL filed a petition with the EPA to expedite rulemaking for the rewrite of the CAIR rules. As a result of EPA's inaction regarding fuel adjustment factors, FPL filed a Writ of Mandamus on December 18, 2009 asking the Court to force EPA to remove the fuel adjustment factors. On January 5, 2010, the Court ordered EPA to respond to FPL's Writ of Mandamus by January 26, 2010. The Court denied FPL's Writ of Mandamus on February 2, 2010. On July 6, 2010 EPA published its proposed Clean Air Transport Rule (CATR) to replace the CAIR rule that had been remanded to EPA by the

Court. EPA has published subsequent Notices of Data Availability (NODAs) and has stated that they intend to publish a final rule by the end of spring 2011. While FPL believes that EPA's proposed CATR addresses the issues raised by FPL in our legal challenges, until a final rule is published it is not known whether the changes will be included. The CATR proposes to replace the existing CAIR with new SO2 and NOx programs that will begin on January 1, 2012.

Continuous Emissions Monitoring System (CEMS) Plan for Gas Turbines (GT) - The Low Mass Emitting (LME) CEMS have been installed, tested, and are now in operation at the Fort Myers, Port Everglades, and Fort Lauderdale Gas Turbine Parks, as required by the CAIR.

FPL has projected O&M expenses of $5,000 per year that will be required for routine maintenance of these CEMS systems. It should be noted that the LME option is available for a GT only if its emissions remain under EPA-prescribed thresholds. If any GT emits more than 50 tons of NOx or 25 tons of SO2 in a given calendar year, the testing for that GT will be required every year, instead of every five years. That would increase the testing costs for non-qualifying GTs to $65,000 per year, along with $5,000 per year for maintenance.

Purchases of allowances – To comply with the CAIR Ozone Season NOx program requirements, FPL purchased CAIR allowances that were needed for compliance at a total cost of $98,325 for compliance year 2009. The 855 CAIR Ozone season allowances, in addition to the 12,418 allowances allocated to FPL by the EPA, were needed to comply with CAIR requirements for fossil generating unit emissions during the May through September 2009 Ozone Season. As a result of the lower than previously projected system load, and changes in FPL's generation plan mentioned above, FPL had sufficient allowances for compliance with the 2010 CAIR NOx Ozone Season and has sufficient allowances for compliance with the CAIR 2010 NOx Annual programs without purchasing additional allowances. Future purchases of allowances will be made as needed for compliance with the annual and ozone season NOx requirements. While FPL has received allocations to its existing CAIR fossil generating units, FPL has projected, but does not know precisely, the number of allowances it will be allocated under the CAIR NOx Annual and Ozone Season new source set-aside program for the West County Energy Center generating units. EPA, in its newly proposed CATR, proposed an allocation method which would allocate to FPL insufficient allowances for compliance with FPL's projected emissions for both the ozone season and annual NOx programs. However, in the January 7, 2011 NODA, EPA proposed two additional allocation methodologies which FPL believes will provide sufficient allowances for compliance with CATR.

Actual CAIR capital costs through 2010 were $408.1 million.

CAIR CAPITAL COST ESTIMATES ($Millions)			
PROJECT	**2011**	**2012**	**TOTAL PROJECT**
SJRPP-SCR/Ammonia Injection System	0.0	0.0	55.3
Scherer-SCR/FGD	97.4	29.4	369.2
800 MW Unit Cycling - Martin	0.2	0.0	58.4
800 MW Unit Cycling - Manatee	1.4	0.0	56.8
CEMS at GTs	Capital project completed	Capital project completed	Capital project completed
Allowances	N/A	N/A	N/A

Actual CAIR O&M expenses through 2010 are $7.1 million.

CAIR O&M EXPENSE ESTIMATES ($Millions)			
PROJECT	**2011**	**2012**	**TOTAL PROJECT**
SJRPP-SCR/Ammonia Injection System	1.405	1.165	1.165 (2012+ annual operating costs are on-going)
Scherer-SCR/FGD	0	3.5	3.5 (2012+ annual operating costs are on-going)
800 MW Unit Cycling – Martin	0	0	2.10
800 MW Unit Cycling – Manatee	0.05	0	1.96
CEMS at GTs	0.005	0.005	0.005 (2011+ annual operating costs are on-going)
Allowances	0	0	N/A

CAMR Compliance Project Update:

On March 15, 2005, EPA issued the Clean Air Mercury Rule to permanently cap and reduce mercury emissions from coal-fired power plants for the first time. In response to the EPA CAMR, the Georgia Environmental Protection Division (EPD) promulgated two major rules to implement mercury reductions within Georgia: a rule to adopt the CAMR federal mercury cap and trade program: Rule 391-3-1-.02(15) – "*Georgia Mercury Trading Rule*" and a Georgia state specific Multipollutant Rule: Rule 391-3-1-.02(2)(sss) – " *Multipollutant Control for Electric Utility Steam Generating Units*" which became effective June 1, 2008. The Multipollutant Rule was promulgated to specify the implementation of specific air pollution control equipment for reductions in mercury (Hg), sulfur dioxide (SO2), and nitrogen oxides (NOx) emissions from identified coal-fired Electric Generating Units (EGUs) within Georgia. Section 4(i) of the Multipollutant Rule requires that Scherer Unit 4 may not be operated after April 30, 2010, unless it is equipped and operated with sorbent injection and a baghouse for the control of Hg emissions.

On February 8, 2008, the United States District Court of Appeals ruled that EPA's Delisting Rule for mercury emissions from coal-fired EGUs utility boilers and the CAMR were unlawful and vacated both rules. On October 28, 2009, EPA published its proposed consent decree with respect to the *"American Nurses Association, et al v. EPA"* Clean Air Act citizen suit. The consent decree establishes a timeline for EPA's proposal of MACT standards for coal- and oil-fired electric utility steam generating units with a proposed rule no later than March 16, 2011 and a final rule no later than November 16, 2011. In December 2009, EPA approved an Information Collection Request (ICR) requiring all coal- and oil-fired electric utility steam generating units to submit emissions data and for a specified list of affected units to perform fuel sampling and stack emission testing of Hazardous Air Pollutants (HAPs). Data collected in the ICR will be used in setting MACT standards of performance for coal- and oil-fired electric utility steam generating unit emissions of HAPs. In Order No. 09-0795-FOF-EI issued November 18, 2009, the Commission approved a new ECRC project for recovery of costs for compliance with the ICR in 2010.

Installation of the Hg controls, and associated continuous Hg emission monitoring that would have been needed to comply with the CAMR requirements remain necessary to comply with the requirements of the Georgia Multipollutant Rule; therefore installation of Hg controls on Plant Scherer Unit 4 must continue. The vacatur of CAMR does not change the compliance obligations at Plant Scherer, including FPL's share of Unit 4. FPL anticipates that controls being installed at Plant Scherer for Hg control will be needed to comply with the monitoring and reporting requirements. This will ultimately be required in order to remain in compliance with monitoring of the final MACT rule expected in late 2011. Specifically, FPL will comply with the Hg reduction requirements of the Georgia Multipollutant Rule by using the following projects identified previously under CAMR:

1. Installation of Fabric Filter Baghouse and Mercury Sorbent Injection System on Scherer Unit 4 (completed 2010).
2. Installation of HgCEMS on Scherer Unit 4 (completed 2009).

3. Installation of HgCEMS on SJRPP Units 1 & 2 (completed in 2008 prior to the EPA decision and certification testing and operation have been delayed until the monitoring requirements begin for Hg MACT compliance).

Construction work completed in 2009 for the Scherer Unit 4 Hg controls included completion of the structural components, fabric filter assembly, and major electrical components at a cost of $44.6 million for 2009. Total capital costs to date for the CAMR project are $105.9 million. Projected annual O&M associated with operation of the Hg controls includes purchase of new sorbent, disposal of spent sorbent, replacement of filter bags, and maintenance activities associated with the baghouse and sorbent injection system, and the maintenance costs associated with FPL's share of the Hg CEMS. FPL's cost associated with the installation of Hg CEMS at SJRPP represented a total capital cost of $ 0.4 million. Projected CAMR O&M expenses for plant Scherer are $4.0 million annually beginning in 2011 primarily for purchase and disposal of sorbents and replacement of bags.

On March 16, 2011 EAP published its proposed Air Toxics Rule in response to the vacatur of the CAMR and De-Listing Rules. EPA's proposed Air Toxics Rule sets limits on emissions of Toxic Metal Hazardous Air Pollutants (HAPs), including Mercury, limits on emissions of acid gasses, and work practice standards for emissions of Organic HAPs. FPL is currently evaluating compliance requirements and potential impacts to operation of its coal-fired generating units. Preliminary review of data indicates that Plant Scherer Unit 4 will comply with the proposed emission limits using the installed baghouse-sorbent injection system following completion of the SCR and FGD installation currently underway to comply with the Georgia Multipollutant Rule. FPL believes that the mercury emission limits in the proposed Air Toxics Rule will likely require installation of baghouse-sorbent injection on the SJRPP units as would have been the case under CAMR. There is currently insufficient test information from the units to determine whether any additional controls may be needed to comply with the proposed Air Toxics Rule. FPL is evaluating the need for additional testing that may be required to determine an appropriate compliance plan.

Actual CAMR capital costs through 2010 are $105.9 million.

CAMR CAPITAL COST ESTIMATES ($Millions)			
PROJECT	**2011**	**2012**	**TOTAL PROJECT**
SJRPP-Mercury CEMS	0	0	0.4
Scherer-Sorbent Injection/Baghouse/ Mercury CEMS	0.2	0.0	106.0

Actual CAMR O&M expenses through 2010 are $1.6 million.

CAMR O&M EXPENSE ESTIMATES ($Millions)			
PROJECT	**2011**	**2012**	**TOTAL PROJECT**
SJRPP-Mercury CEMS	0	0	0.0
Scherer-Sorbent Injection/Baghouse/ HgCEMS	4.0	4.0	4.0 (2011+ annual operating costs are on-going)

CAVR / BART Project Update:

FPL successfully concluded negotiations with the Florida Department of Environmental Protection (FDEP or the Department) regarding Turkey Point Units 1 & 2 in February 2009, with the Department accepting FPL's proposed plan to comply with the BART requirements under the Regional Haze program. FPL and the FDEP agreed on the following compliance options for particulate and opacity control under BART:

1. installation of modern multi-cyclone separators;
2. switching to a lower sulfur fuel (from 1.0% to 0.7%);
3. adoption of a lower Particulate Matter (PM) emission limit from 0.1 lb./mmbtu to 0.07 lb/mmbtu;
4. conducting a fuel additive test program with the goal of a further PM reduction to 0.05 lb/mmbtu, if feasible; and
5. accepting a steady-state opacity limit of 20% based on an annual average for 99% of the annual steady-state operating periods.

The projected cost of this Emission Reduction Strategy is estimated to be $7.3 million Capital with $1.9 million increased O&M per year. FPL will not include recovery of these costs under the ECRC.

FDEP issued the final permit for compliance with BART on April 14, 2009 completing the BART project. The required implementation date will not be until December, 2013. In order to minimize the effect on total system load and availability, installation will be conducted using a staged approach, with work done during the unit's planned outages currently scheduled between now and 2013.

In addition to the compliance requirement under the BART rule, FDEP's Regional Haze Rule 62-296.341, Reasonable Progress Control Technology (RPCT), requires that an electric utility unit which had a "Significant Contribution to Regional Haze" as evidenced by SO2 emissions in 2002 address visibility impacts to the Class 1 areas. FDEP has identified six FPL generating units which had been determined to be subject to the RPCT requirements: Turkey Point Units 1 & 2, Port Everglades Units 3 & 4, and Manatee Units 1 & 2.

FPL will need to address the RPCT requirements through submittal of an air construction permit that evaluates the RPCT factors for each of the six generating units. The permit application must be submitted no later than January 31, 2012. In compliance with the RPCT requirements, the FDEP must issue the final air construction permits implementing the applicant's RPCT proposal no later than December 31, 2017. FPL plans to begin analysis and evaluation in 2012 for the RPCT factors for the affected generating units once the State of Florida has received approval from EPA.

EPA has told FDEP that it will not approve Florida's Draft CAVR State Implementation Plan (SIP) primarily due to the FDEP Reasonable Progress Control Technology (RPCT) Rule which uses a permit application process that EPA finds unacceptable. FDEP has indicated that it will withdraw the RPCT Rule from the FAC and delete the RPCT provision from the SIP. FDEP contends that visibility improvements at Florida's Class 1 Areas will meet the Reasonable Progress glide slope in 2018 by way of existing air rules promulgated previously. Therefore, no additional rulemaking and subsequent controls will be needed for CAVR. FDEP expects to remove the RPCT rule (62-296.341, F.A.C.) after other Southeast states receive SIP approval in the spring of 2011.

Actual CAVR capital costs through 2010 are $0.

Actual CAVR O&M expenses through 2010 are $0.041 million. FPL has projected a preliminary estimated O&M total cost of $0.030 million in 2012 for the required RPCT analysis of the six generating units.

CAVR/BART O&M EXPENSE ESTIMATES ($Millions)			
PROJECT	**2011**	**2012**	**TOTAL PROJECT***
Reasonable Process Control Technology	0	.030	0.070

* *Through 2012*

FPL Plant	State IWW Permit No.	Permit Issuance Date	Permit Expiration Date	Permit Status	Old Permit WET Requirement	New or Anticipated WET Permit Requirement	Comments
Cape Canaveral	FL0001473	2/11/2011	2/10/2016	Final	None	Chronic Testing - 4 times per year - may be reduced to semi-annual testing after 4 successful tests	Testing will resume upon completion of CCEC - mid-2013
Cutler	FL0001481	7/15/2011	7/14/2016	Final	None	N/A	Assumed retiring in 2012 - No Costs Included
Ft. Lauderdale	FL0001503	6/25/2010	6/24/2015	Final	Acute quarterly, reduced to semi-annual if satisfactory	Chronic Testing - 4 times per year - may be reduced to semi-annual testing after 4 successful tests	
Ft. Myers	FL0001490	12/10/2010	12/9/2015	Final	None	Chronic Testing - 4 times per year - may be reduced to semi-annual testing after 4 successful tests	
Manatee	FL0032174	Final Permit Expected late 2011		Draft Issued 7/6/2011	None	Chronic Testing - 4 times per year - may be reduced to semi-annual testing after 4 successful tests	Testing once per year with spillway gate test
Martin	FL0030988	6/11/2008	6/10/2013	Old Permit	None	Chronic Testing - 4 times per year - may be reduced to semi-annual testing after 4 successful tests	Testing once per year with spillway gate test
Pt. Everglades	FL0001538	7/22/2010	7/21/2010	Final	Acute quarterly, reduced testing if satisfactory	Chronic Testing - 4 times per year - may be reduced to semi-annual testing after 4 successful tests	
Putnam	FL0032166	4/7/2007	4/5/2012	Old Permit	Acute semi-annually - possible reduction after 6 successful tests	Chronic Testing - 4 times per year - may be reduced to semi-annual testing after 4 successful tests	
Riviera	FL0001546	8/28/2010	8/27/2015	Final	None	Chronic Testing - 4 times per year - may be reduced to semi-annual testing after 4 successful tests	Testing will resume upon completion of RCEC - mid-2014
Sanford	FL0001554	8/15/2008	8/14/2013	Old Permit	Chronic Testing - 4 times per year - may be reduced to semi-annual testing after 4 successful tests	Chronic Testing - 4 times per year - may be reduced to semi-annual testing after 4 successful tests	No Change - No costs considered
St. Lucie	FL0002208	Final Permit Expected late 2011		Draft Issued 4/4/2011	Chronic Testing - 4 times per year - may be reduced to semi-annual testing after 4 successful tests	Chronic Testing - 4 times per year - may be reduced to semi-annual testing after 4 successful tests	

Docket No. 110007-EI
Changes and Anticipated Changes in WET Testing for FPL Facilities
Exhibit RRL-4, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI EXHIBIT 9
PARTY FLORIDA POWER & LIGHT CO. (DIRECT)
DESCRIPTION R. R. LABAUVE (RRL-4)
DATE 11/01/11

Florida Department of Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Charlie Crist
Governor

Jeff Kottkamp
Lt. Governor

Michael W. Sole
Secretary

JUL 29 2010

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

In the Matter of an
Application for Permit by:

Mr. Rudy Sanchez
Plant General Manager
Florida Power & Light Company (FPL)
P.O. Box 13118
Ft Lauderdale, Florida 33316

PA File No. FL0001538-007-IW1S
Broward County
Port Everglades Plant
NPDES Permit No. FL0001538

NOTICE OF PERMIT ISSUANCE

Enclosed is Permit Number FL0001538 to Florida Power & Light Company, authorizing wastewater discharge from the Port Everglades Plant to the Intracoastal Waterway, a Class III marine water, issued under Section 403.0885, Florida Statutes, and DEP Rule 62-620, Florida Administrative Code.

Monitoring requirements under this permit are effective on the first day of the second month following permit issuance. Until such time, the permittee shall continue to monitor and report in accordance with previously effective permit requirements, if any.

Any party to this order (permit) has the right to seek judicial review of the permit action under Section 120.68, Florida Statutes, by the filing of a notice of appeal under Rules 9.110 and 9.190, Florida Rules of Appellate Procedure, with the Clerk of the Department of Environmental Protection, Office of General Counsel, 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate district court of appeal. The notice of appeal must be filed within 30 days from the date when this document is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Janet G. Llewellyn
Director
Division of Water Resource Management
2600 Blair Stone Road
Tallahassee, FL 32399-2400
(850) 245-8336

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI **EXHIBIT** 10
PARTY FLORIDA POWER & LIGHT CO. (DIRECT)
DESCRIPTION R. R. LAUBAUVE (RRL-5)
DATE 11/01/11

FILING AND ACKNOWLEDGMENT

FILED, on this date, under Section 120.52, Florida Statutes, with the designated deputy clerk, receipt of which is hereby acknowledged.

S. Shields 07.27.10
Clerk Date

CERTIFICATE OF SERVICE

The undersigned hereby certifies that this DOCUMENT AND ATTACHMENTS and all copies were mailed before the close of business on 07-27-10 to the listed persons.

S. Shields 07-27-10
Name Date

Certified copies furnished to:
- Mark Nuhfer, NPDES Permitting Section, EPA Region 4, Atlanta, GA
- Chairman, Board of Broward County Commissioners
- Ron Mezich, FWC Tallahassee
- Jim Valade, U.S. Fish & Wildlife Service

Copies furnished by U.S. mail to:
- Andy Flajole, Florida Power and Light

Copies furnished by intradepartmental mail to:
- Justin Wolfe, Esq., DEP Tallahassee
- Tim Powell, P.E., DEP West Palm Beach
- Michael Hambor, DEP West Palm Beach

STATE OF FLORIDA
INDUSTRIAL WASTEWATER FACILITY PERMIT

PERMITTEE:
Florida Power & Light Company
P.O. Box 13118
Ft. Lauderdale, FL 33316

PERMIT NUMBER: FL0001538 (Major)
FILE NUMBER: FL0001538-007-IW1S
ISSUANCE DATE: July 22, 2010
EXPIRATION DATE: July 21, 2015

RESPONSIBLE OFFICIAL:

Mr. Jeff Smith
Plant General Manager
P.O. Box 13118
Ft. Lauderdale, Florida 33316
(954) 527-3601

FACILITY:

Florida Power & Light Company
Port Everglades Plant
8100 Eisenhower Blvd
Fort Lauderdale, FL 33316
Broward County
Latitude: 26°5' 5.97" N Longitude: 80°7' 31.87" W

This permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and applicable rules of the Florida Administrative Code (F.A.C.) and constitutes authorization to discharge to waters of the state under the National Pollutant Discharge Elimination System. This permit does not constitute authorization to discharge wastewater other than as expressly stated in this permit. The above named permittee is hereby authorized to operate the facilities in accordance with the documents attached hereto and specifically described as follows:

FACILITY DESCRIPTION:
The facility is an electric generating plant with a total nominal generating capacity of approximately 1200 megawatts (MW), with a total production capacity of 1254 MW using natural gas or oil as fuel. The existing generating facility consists of four dual-fired steam electric generating units (Units 1, 2, 3, and 4) with nameplate ratings of 200 MW, 200 MW, 400 MW, and 400 MW, respectively. Seawater from Port Everglades harbor slip #3 is drawn into the facility's intake canal for use as once-through cooling water which discharges via the facility's discharge canal to the Intracoastal Waterway.

WASTEWATER TREATMENT:
Various wastewater streams generated at the facility include once-through cooling water, sluice water, economizer hopper wash, boiler blowdown, reverse osmosis concentrate, air preheater wash, dust collector wash, equipment wash, boiler fireside wash, stack wash and water treatment system effluent streams. The low volume wastewater treatment system includes a solids settling basin, precipitation basin, percolation basin and their overflow areas. The solids settling and precipitation basins are lined with an impermeable liner and the percolation basin has a limestone bottom. The equipment area runoff treatment system is designed to collect and retain the first inch of rainfall that falls on the plant's equipment area, minimal flows from the service water rinses in the power block area, and boiler blowdown as an infrequent alternate flow. Drainage from areas subject to oil contamination is routed through oil/water separators or oil traps. Runoff in excess of the first inch may be routed to the discharge canal.

REUSE OR DISPOSAL:

Surface Water Discharge D-001: An existing 1228 MGD Annual Average Daily Flow (1295 MGD Maximum Daily Flow) permitted discharge to Intracoastal Waterway, Class III Marine Waters, (WBID 3226G3). The Point of Discharge (POD) into waters of the State is located at a cross-section through the discharge canal 600 feet downstream from the Unit 1 cooling water discharge structure. The point of discharge is located approximately at latitude 26° 05' 01" N, longitude 80° 07' 26" W.

PERMITTEE:	Florida Power and Light	PERMIT NUMBER:	FL0001538 (Major)
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Surface Water Discharge D-00B3: An existing discharge to the Intracoastal Waterway, Class III Marine Waters, (WBID 3226G3). The East Tank Farm Stormwater point of discharge is located approximately at latitude 26° 04' 59" N, longitude 80°7' 20" W.

Land Application R-001: An existing land application system consisting of Percolation Basin (Basin B-2) located approximately at latitude 26° 04' 59" N, longitude 80°7' 32" W.

Land Application R-002: An existing land application system consisting of Stormwater Basin (Basin B-5) located approximately at latitude 26° 05' 00" N, longitude 80°7' 28" W.

Internal Outfall I-019: An existing discharge to the intake canal, Class III Marine Waters, (WBID 3226G3). The point of discharge is located approximately at latitude 26° 05' 10" N, longitude 80° 07' 32" W.

Internal Outfall I-01B1: An existing discharge to the discharge canal and ultimately to the Intracoastal Waterway, Class III Marine Waters, (WBID 3226G3). The Stormwater Forwarding Basin and Sump (B5/S-11) point of discharge is located approximately at latitude 26° 05' 01" N, longitude 80° 07' 29" W.

Internal Outfall I-012: An existing permitted discharge to the intake canal.

Internal Outfall I-016: An existing permitted discharge to the intake canal.

Internal Outfall I-111: An existing 230 MGD Daily Maximum Flow permitted discharge to the discharge canal.

Internal Outfall I-112: An existing 230 MGD Daily Maximum Flow permitted discharge to the discharge canal.

Internal Outfall I-113: An existing 396 MGD Daily Maximum Flow permitted discharge to the discharge canal.

Internal Outfall I-114: An existing 396 MGD Daily Maximum Flow permitted discharge to the discharge canal.

Internal Outfall I-181, I-182, I-183, I-184: Existing permitted discharges from the auxiliary equipment cooling water systems for Units 1, 2, 3, and 4 to the discharge canal, respectively.

Internal Outfall I-1B2: An existing permitted discharge to the intake canal.

Internal Outfall I-1D1, I-1D2, I-1D3, I-1D4: An existing permitted discharge to the discharge canal.

IN ACCORDANCE WITH: The limitations, monitoring requirements and other conditions set forth in this Cover Sheet and Part I through Part IX on pages 1 through 30 of this permit.

PERMITTEE: Florida Power and Light
FACILITY: Port Everglades Power Plant

PERMIT NUMBER: FL0001538-007 (Major)
EXPIRATION DATE: Draft

I. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

A. Surface Water Discharges

1. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge boiler blowdown, once-through non-contact cooling water, auxiliary equipment cooling water, reverse osmosis reject water, intake screen wash water, and stormwater from **Outfall D-001** to the Intracoastal Waterway. Such discharge shall be limited and monitored by the permittee as specified below:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Oxidants, Total Residual	mg/L	Max Max	0.01 0.01	Monthly Average Daily Maximum	Bi-weekly	Grab	EFF-5	See I.B.10
Temperature, Water	Deg F	Max Max	Report Report	Monthly Average Daily Maximum	Bi-weekly	Instantaneous	EFF-5	
Aluminum, Total Recoverable	mg/L	Max Max	1.5 1.5	Monthly Average Daily Maximum	Semi-Annually	Grab	EFF-5	
Arsenic, Total Recoverable	ug/L	Max Max	36 36	Monthly Average Daily Maximum	Semi-Annually	Grab	EFF-5	
Cadmium, Total Recoverable	ug/L	Max Max	9.3 9.3	Monthly Average Daily Maximum	Semi-Annually	Grab	EFF-5	
Copper, Total Recoverable	ug/L	Max Max	3.7 3.7	Monthly Average Daily Maximum	Semi-Annually	Grab	EFF-5 SWB-1	See I.A.5
Oxygen, Dissolved (DO)	mg/L	Max Min	Report Report	Monthly Average Daily Minimum	Semi-Annually	Grab	EFF-5	See I.A.6
Fluoride, Dissolved (as F)	mg/L	Max Max	5.0 5.0	Monthly Average Daily Maximum	Semi-Annually	Grab	EFF-5	
Iron, Total Recoverable	mg/L	Max Max	0.3 0.3	Monthly Average Daily Maximum	Semi-Annually	Grab	EFF-5	
Lead, Total Recoverable	ug/L	Max Max	5.6 5.6	Monthly Average Daily Maximum	Semi-Annually	Grab	EFF-5	
Mercury, Total Recoverable	ug/L	Max Max	0.025 0.025	Monthly Average Daily Maximum	Semi-Annually	Grab	EFF-5	
Nickel, Total Recoverable	ug/L	Max Max	8.3 8.3	Monthly Average Daily Maximum	Semi-Annually	Grab	EFF-5 SWB-1	See I.A.5
Selenium, Total Recoverable	ug/L	Max Max	71 71	Monthly Average Daily Maximum	Semi-Annually	Grab	EFF-5	
Zinc, Total Recoverable	ug/L	Max Max	86 86	Monthly Average Daily Maximum	Semi-Annually	Grab	EFF-5	
Chronic Whole Effluent Toxicity, 7-Day IC25 (Mysidopsis bahia)	percent	Min	100	Single Sample	Quarterly	24-hr FPC	EFF-5	See I.A.4
Chronic Whole Effluent Toxicity, 7-Day IC25 (Menidia beryllina)	percent	Min	100	Single Sample	Quarterly	24-hr FPC	EFF-5	See I.A.4

2. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.A.1. and as described below:

Monitoring Site Number	Description of Monitoring Site
EFF-5	600 feet downstream from the Unit 1 discharge structure physically demarcated by oil spill boom across the discharge canal.
SWB-1	Background from intake canal at a point upstream (North) of outfalls I-012 and I-016.

3. The discharge shall not contain components that settle to form putrescent deposits or float as debris, scum, oil, or other matter. *[62-302.500(1)(a)]*

4. The permittee shall comply with the following requirements to evaluate chronic whole effluent toxicity of the discharge from outfall D-001.

   a. Effluent Limitation
      (1) In any routine or additional follow-up test for chronic whole effluent toxicity, the 25 percent inhibition concentration (IC25) shall not be less than 100% effluent. *[Rules 62-302.530(61) and 62-4.241(1)(b), F.A.C.]*
      (2) For acute whole effluent toxicity, the 96-hour LC50 shall not be less than 100% effluent in any test. Acute whole effluent toxicity testing is not required except as provided in 4.g.(4). *[Rules 62-302.500(1)(a)4. and 62-4.241(1)(a), F.A.C.]*

   b. Monitoring Frequency
      (1) Routine toxicity tests shall be conducted once every three months, the first starting within 60 days of the issuance date of this permit and lasting for the duration of this permit.
      (2) Upon completion of four consecutive, valid routine tests that demonstrate compliance with the effluent limitation in 4.a.(1) above, the permittee may submit a written request to the Department for a reduction in monitoring frequency to once every six months. The request shall include a summary of the data and the complete bioassay laboratory reports for each test used to demonstrate compliance. The Department shall act on the request within 45 days of receipt. Reductions in monitoring shall only become effective upon the Department's written confirmation that the facility has completed four consecutive valid routine tests that demonstrate compliance with the effluent limitation in 4.a.(1) above.
      (3) If a test within the sequence of the four is deemed invalid based on the acceptance criteria in EPA-821-R-02-014, but is replaced by a repeat valid test initiated within 21 days after the last day of the invalid test, the invalid test will not be counted against the requirement for four consecutive valid tests for the purpose of evaluating the reduction of monitoring frequency.

   c. Sampling Requirements
      (1) For each routine test or additional follow-up test conducted, a total of three 24-hour composite samples of final effluent shall be collected and used in accordance with the sampling protocol discussed in EPA-821-R-02-014, Section 8.
      (2) The first sample shall be used to initiate the test. The remaining two samples shall be collected according to the protocol and used as renewal solutions on Day 3 (48 hours) and Day 5 (96 hours) of the test.
      (3) Samples for routine and additional follow-up tests shall not be collected on the same day.

   d. Test Requirements
      (1) Routine Tests: All routine tests shall be conducted using a control (0% effluent) and a minimum of five test dilutions: 100%, 50%, 25%, 12.5%, and 6.25% final effluent.
      (2) The permittee shall conduct 7-day survival and growth chronic toxicity tests with a mysid shrimp, Americamysis (Mysidopsis) bahia, Method 1007.0, and an inland silverside, Menidia beryllina, Method 1006.0, concurrently.
      (3) All test species, procedures and quality assurance criteria used shall be in accordance with <u>Short-term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Marine and Estuarine Organisms</u>, 3rd Edition, EPA-821-R-02-014. Any deviation of the bioassay procedures outlined herein shall be submitted in writing to the Department for review and approval prior to use. In the event the above method is revised, the permittee shall conduct chronic toxicity testing in accordance with the revised method.
      (4) The control water and dilution water used shall be artificial sea salts as described in EPA-821-R-02-014, Section 7.2. The test salinity shall be determined as follows:
         (a) For the Americamysis bahia bioassays, the effluent shall be adjusted to a salinity of 20 parts per thousand (ppt) with artificial sea salts. The salinity of the control/dilution water (0% effluent) shall be 20 ppt. If the salinity of the effluent is greater than 20 ppt, no salinity adjustment shall be made to the effluent and the test shall be run at the effluent salinity. The salinity of the control/dilution water shall match the salinity of the effluent.

(b) For the Menidia beryllina bioassays, if the effluent salinity is less than 5ppt, the salinity shall be adjusted to 5 ppt with artificial sea salts. The salinity of the control/dilution water (0% effluent) shall be 5 ppt. If the salinity of the effluent is greater than 5 ppt, no salinity adjustment shall be made to the effluent and the test shall be run at the effluent salinity. The salinity of the control/dilution water shall match the salinity of the effluent.

(c) If the salinity of the effluent requires adjustment, a salinity adjustment control should be prepared and included with each bioassay. The salinity adjustment control is intended to identify toxicity resulting from adjusting the effluent salinity with artificial sea salts. To prepare the salinity adjustment control, dilute the control/dilution water to the salinity of the effluent and adjust the salinity of the salinity adjustment control at the same time and to the same salinity that the salinity of the effluent is adjusted using the same artificial sea salts.

e. Quality Assurance Requirements

(1) A standard reference toxicant (SRT) quality assurance (QA) chronic toxicity test shall be conducted with each species used in the required toxicity tests either concurrently or initiated no more than 30 days before the date of each routine or additional follow-up test conducted. Additionally, the SRT test must be conducted concurrently if the test organisms are obtained from outside the test laboratory unless the test organism supplier provides control chart data from at least the last five monthly chronic toxicity tests using the same reference toxicant and test conditions. If the organism supplier provides the required SRT data, the organism supplier's SRT data and the test laboratory's monthly SRT-QA data shall be included in the reports for each companion routine or additional follow-up test required.

(2) If the mortality in the control (0% effluent) exceeds 20% for either species in any test or any test does not meet "test acceptability criteria", the test for that species (including the control) shall be invalidated and the test repeated. Test acceptability criteria for each species are defined in EPA-821-R-02-014, Section 14.12 (Americamysis bahia) and Section 13.12 (Menidia beryllina). The repeat test shall begin within 21 days after the last day of the invalid test.

(3) If 100% mortality occurs in all effluent concentrations for either species prior to the end of any test and the control mortality is less than 20% at that time, the test (including the control) for that species shall be terminated with the conclusion that the test fails and constitutes non-compliance.

(4) Routine and additional follow-up tests shall be evaluated for acceptability based on the observed dose-response relationship as required by EPA-821-R-02-014, Section 10.2.6., and the evaluation shall be included with the bioassay laboratory reports.

f. Reporting Requirements

(1) Results from all required tests shall be reported on the Discharge Monitoring Report (DMR) as follows:

(a) Routine and Additional Follow-up Test Results: The calculated IC25 for each test species shall be entered on the DMR.

(2) A bioassay laboratory report for each routine test shall be prepared according to EPA-821-R-02-014, Section 10, Report Preparation and Test Review, and mailed to the Department at the address below within 30 days after the last day of the test.

(3) For additional follow-up tests, a single bioassay laboratory report shall be prepared according to EPA-821-R-02-014, Section 10, and mailed within 30 days after the last day of the second valid additional follow-up test.

(4) Data for invalid tests shall be included in the bioassay laboratory report for the repeat test.

(5) The same bioassay data shall not be reported as the results of more than one test.

(6) All bioassay laboratory reports shall be sent to:
Florida Department of Environmental Protection
Southeast District Office
400 North Congress Avenue
West Palm Beach, Florida 33401

g. Test Failures

(1) A test fails when the test results do not meet the limits in 4.a.(1).

(2) Additional Follow-up Tests:

(a) If a routine test does not meet the chronic toxicity limitation in4.a.(1) above, the permittee shall notify the Department at the address above within 21 days after the last day of the failed routine test and conduct two additional follow-up tests according to 4.d. on each species that failed the test on each species that failed the test in accordance with 4.d.

(b) The first test shall be initiated within 28 days after the last day of the failed routine test. The remaining additional follow-up tests shall be conducted weekly thereafter until a total of two valid additional follow-up tests are completed.

(c) The first additional follow-up test shall be conducted using a control (0% effluent) and a minimum of five dilutions: 100%, 50%, 25%, 12.5%, and 6.25% effluent. The permittee may modify the dilution series in the second additional follow-up test to more accurately bracket the toxicity such that at least two dilutions above and two dilutions below the target concentration and a control (0% effluent) are run. All test results shall be analyzed according to the procedures in EPA-821-R-02-014.

(3) In the event of three valid test failures (whether routine or additional follow-up tests) within a 12-month period, the permittee shall notify the Department within 21 days after the last day of the third test failure.

(a) The permittee shall submit a plan for correction of the effluent toxicity within 60 days after the last day of the third test failure.

(b) The Department shall review and approve the plan before initiation.

(c) The plan shall be initiated within 30 days following the Department's written approval of the plan.

(d) Progress reports shall be submitted quarterly to the Department at the address above.

(e) During the implementation of the plan, the permittee shall conduct quarterly routine whole effluent toxicity tests in accordance with 4.d. Additional follow-up tests are not required while the plan is in progress. Following completion or termination of the plan, the frequency of monitoring for routine and additional follow-up tests shall return to the schedule established in 4.b.(1). If a routine test is invalid according to the acceptance criteria in EPA-821-R-02-014, a repeat test shall be initiated within 21 days after the last day of the invalid routine test.

(f) Upon completion of four consecutive quarterly valid routine tests that demonstrate compliance with the effluent limitation in 4.a.(1) above, the permittee may submit a written request to the Department to terminate the plan. The plan shall be terminated upon written verification by the Department that the facility has passed at least four consecutive quarterly valid routine whole effluent toxicity tests.

If a test within the sequence of the four is deemed invalid, but is replaced by a repeat valid test initiated within 21 days after the last day of the invalid test, the invalid test will not be counted against the requirement for four consecutive quarterly valid routine tests for the purpose of terminating the plan.

(4) If chronic toxicity test results indicate greater than 50% mortality within 96 hours in an effluent concentration equal to or less than the effluent concentration specified as the acute toxicity limit in 4.a.(2), the Department may revise this permit to require acute definitive whole effluent toxicity testing.

(5) The additional follow-up testing and the plan do not preclude the Department taking enforcement action for acute or chronic whole effluent toxicity failures.

[62-4.241, 62-620.620(3)]

5. The actual limit shall be the water quality standard set forth in Rule 62-302.530, F.A.C. for Class III Marine waters as specified here or the concentration of the intake cooling water, whichever is greater. If the Outfall D-001 sample exceeds the intake concentration (and the intake concentration exceeds the water quality standard), the concentration of a minimum of five (5) additional subsamples shall be analyzed from the original intake and outfall samples. The results shall be evaluated using the "student's t-test" comparing discharge concentrations with the intake concentrations. Unless the discharge concentration exceeds the intake concentration at the 95% confidence level, the facility shall be in compliance with the limitation.

6. Dissolved Oxygen (DO) concentration shall not be less than DO measured at intake monitoring location INT- 1, 2, 3, and 4, unless the intake DO is greater than the applicable Water Quality Criteria (WQC) in Rule 62-302.530(31), F.A.C., in which case the discharge limitation shall be the WQC. A measurement tolerance of 0.5 mg/L shall be allowed for DO field measurements.

PERMITTEE: Florida Power and Light
FACILITY: Port Everglades Power Plant

PERMIT NUMBER: FL0001538 (Major)
EXPIRATION DATE: July 21, 2015

7. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge stormwater from **Outfall D-00B3 (East Tank Farm)** to the Intracoastal Waterway. Such discharge shall be limited and monitored by the permittee as specified below:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Daily Average Daily Maximum	Weekly	Calculated	FLW-12	
Petrol Hydrocarbons, Total Recoverable	mg/L	Max Max	5.0 5.0	Daily Average Daily Maximum	Monthly	Grab	EFF-9	
Turbidity	NTU	Max	Report Report	Single Sample Single Sample	Monthly	Grab	SWB-1 EFF-9	See I.A.10
Solids, Total Suspended	mg/L	Max Max	30.0 100.0	Daily Average Daily Maximum	Monthly	Grab	EFF-9	
pH	s.u.	Max Min Max Min	Report Report Report Report	Daily Maximum Daily Minimum Daily Maximum Daily Minimum	Monthly	Grab	SWB-1 SWB-1 EFF-9 EFF-9	See I.A.11

8. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.A.7. and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-12	Calculated based on pump rates and duration of pumping.
EFF-9	Nearest accessible point after final treatment but prior to actual discharge or mixing with the receiving waters.
SWB-1	Background from intake canal at a point upstream (North) of outfalls I-012 and I-016.

9. The discharge shall not contain components that settle to form putrescent deposits or float as debris, scum, oil, or other matter. [62-302.500(1)(a)]

10. The limit for "Turbidity" shall be calculated as follows:

    Limit = Background Turbidity + 29 NTU

    The measured effluent value shall be recorded on the DMR in the parameter row for "Turbidity (effluent)." The measured background value shall be recorded on the DMR in the parameter row for "Turbidity (background)" The calculated effluent limit shall be recorded on the DMR in the parameter row for "Turbidity (calculated limit)." Compliance with the effluent limitation is determined by calculating the difference between the measured effluent value and the calculated. The compliance value shall be recorded on the DMR in the parameter row for "Turbidity (effluent minus calculated limit)." The compliance value shall not exceed 0.00. *[62-302.530(69)]*

11. Discharge pH shall not vary more than one unit above or below natural background, as defined in Rules 62-302.200(15) and 62-302.530(51)(c), F.A.C., provided that the pH is not lowered to less than 6.0 units or raised above 8.5 units. If natural background is less than 6.0 units, the pH shall not vary below natural background, or vary more than one unit above natural background. If natural background is higher than 8.5 units, the pH shall not vary above natural background or vary more than one unit below natural background.

B. Internal Outfalls

1. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **Water Treatment System Effluent Streams from Internal Outfall I-012** to the intake canal. Such discharge shall be limited and monitored by the permittee as specified:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Monthly Average Daily Maximum	Semi-Annually	Calculated	FLW-9	See I.B.3
Oil and Grease	mg/L	Max Max	15.0 20.0	Monthly Average Daily Maximum	Semi-Annually	Grab	EFF-7	See I.B.3
Solids, Total Suspended	mg/L	Max Max	30.0 100.0	Monthly Average Daily Maximum	Semi-Annually	Grab	EFF-7	See I.B.3
pH	s.u.	Min Max	6.0 9.0	Daily Minimum Daily Maximum	Semi-Annually	Grab	EFF-7	See I.B.3

2. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.1. and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-9	Calculated based on water treatment system efficiency ratio.
EFF-7	Water treatment system effluent point prior to entering the intake canal.

3. Water treatment system filter backwash and softener regeneration are discharged to the lined solids settling basin. Other water treatment system effluent streams are discharged to the intake canal but may also be discharged to the lined solids settling basin as an alternate disposal method.

4. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **Boiler Blowdown from Internal Outfall I-016** to the intake canal. Such discharge shall be limited and monitored by the permittee as specified below:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max	Report	Monthly Average	Daily	Calculated	FLW-10	
Flow, Total Volume	Mgal	Max	Report	Monthly Average	Monthly	Calculated	EFF-6	
Solids, Total Suspended	mg/L	Max Max	30.0 100.0	Monthly Average Daily Maximum	Bi-weekly	Grab	EFF-6	
Oil and Grease	mg/L	Max Max	15.0 20.0	Monthly Average Daily Maximum	Bi-weekly	Grab	EFF-6	
Hydrazine	mg/L	Max	0.3	Daily Maximum	Per discharge	Grab	EFF-6	See I.B.6
pH	s.u.	Min Max	6.0 9.0	Daily Minimum Daily Maximum	Bi-weekly	Grab	EFF-6	

5. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.4. and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-10	Calculated based on representative conductivity measurements.
EFF-6	Boiler blowdown recovery basin outlet prior to discharge to the intake canal.

6. The monitoring frequency for hydrazine shall be once per discharge event. A discharge event is defined as a cold dump of the boiler following maintenance activities or cold stand-by status which requires hydrazine to be added

to the boiler water to achieve concentrations higher than normal for protection of metal surfaces. Boiler blowdown, under normal operating conditions with hydrazine concentrations of 10 to 20 ug/l, may be discharged without limitations or monitoring requirements for hydrazine.

7. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **Once-Through Non-Contact Cooling Water (OTCW) from Internal Outfalls I-111, I-112, I-113, and I-114** from Units 1, 2, 3, and 4, respectively, to discharge canal to the Intracoastal Waterway. Such discharge shall be limited and monitored by the permittee as specified below:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Monthly Average Daily Maximum	Continuous	Calculated	FLW-1, 2, 3, 4	See VI.5
Temperature, Water	Deg F	Max Max	Report Report	Monthly Average Daily Maximum	Continuous	Recorder	EFF-1, 2, 3, 4	See I.B.9
Temp. Diff. between Intake and Discharge	Deg F	Max Max	Report Report	Monthly Average Daily Maximum	6/Day	Calculated	INT-1, 2, 3, 4 EFF-1, 2, 3, 4	See I.B.9
Oxidants, Total Residual	mg/L	Max Max	0.20 0.20	Monthly Average Daily Maximum	Weekly	Grab	EFF-1, 2, 3, 4	See I.B.10
Chlorination Duration	min/day	Max	120	Daily Maximum	Daily	Pump logs	INT-1, 2, 3, 4	

8. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.7. and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-1, 2, 3, 4	Calculated based on pump performance curves, system head curves and run times for Units 1, 2, 3, and 4, respectively.
EFF-1, 2, 3, 4	OTCW outlets for Units 1, 2, 3, and 4, respectively.
INT-1, 2, 3, 4	OTCW intakes for Units 1, 2, 3, and 4, respectively.

9. Discharge and intake temperatures shall be measured continuously. However, the monthly average and daily average values for discharge temperature and temperature rise shall be determined, during a given calendar month, from daily temperature readings taken at uniform intervals not greater than four hours.

10. Total Residual Oxidants (TRO) means the value obtained using the amperometric titration method for total residual chlorine or the Hach model 19300 or equivalent). Testing for TRO by titration shall be conducted according to either the low-level amperometric method, or the DPD calorimetric method as specified in section 4500-Cl E. or 4500 Cl G., respectively, Standard Methods for the examination of Water and Waste water, 18th Edition (or most current edition).

The permittee shall collect samples when chlorine is in use. TRO monitoring requirements for either Units 1, 2, 3 or 4 are not applicable for any week in which chlorine is not added to that unit. Monitoring requirements for the point of discharge are not applicable for any week in which chlorine is not added to anyof the units. No more than one unit shall discharge total residual oxidant at any one time.

Multiple grabs for TRO shall be defined as once per five minutes during TRO discharge periods of 30 minutes or less and once per 15 minutes for periods exceeding 30 minutes with no less than four analyses during the period of TRO discharge (sampling shall be continued until the end of the TRO discharge).

11. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **Auxiliary Equipment Cooling Water (AECW) from Internal Outfalls I-**

PERMITTEE:	Florida Power and Light	PERMIT NUMBER:	FL0001538 (Major)
FACILITY:	Port Everglades Power Plant	EXPIRATION DATE:	July 21, 2015

1D1, I-1D2, I-1D3, and I-1D4 from Units 1, 2, 3, and 4, respectively, used in lieu of OTCW during periods of Reserve Shutdown or periods of circulation water pump malfunction, to discharge canal to Intracoastal Waterway. Such discharge shall be limited and monitored by the permittee as specified below:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Monthly Average Daily Maximum	Weekly	Calculated	FLW-5, 6, 7, 8	See VI.5
Temp. Diff. between Sample and Upstrm	Deg F	Max Max	20.0 20.0	Monthly Average Daily Maximum	6/Day	Calculated	INT-5, 6, 7, 8 EFF-1, 2, 3, 4	See I.B.13

12. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.11. and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-5, 6, 7, 8	Calculated based on pump performance curves, system head curves and run times for Units 1, 2, 3, and 4, respectively.
INT-5, 6, 7, 8	AECW intakes for Units 1, 2, 3, and 4, respectively.
EFF-1, 2, 3, 4	OTCW outlets for Units 1, 2, 3, and 4, respectively.

13. The permittee may notify the Department after one year's data collection in order to request a modification of the permit to include an actual temperature rise limit based on operational data.

14. The permittee shall maintain current travelling screen practices at Units 1, 2, 3and 4 so as to assure that the screens are cycled a minimum of twice during each 24 hours of operation unless precluded by repair /maintenance requirements.

15. The permittee shall develop a plan in accordance with the schedule in Condition VI.6 to help return live fish, shellfish, and other aquatic organisms collected or trapped on the intake screens to their natural habitat. Other material shall be removed from the intake screens and disposed of in accordance with all existing Federal, State and /or local laws and regulations that apply to waste disposal. Such material shall not be returned to the receiving waters.

16. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge equipment and non-equipment area stormwater and boiler blowdown from **Outfall I-01B1** to the Intracoastal Waterway. Such discharge shall be limited and monitored by the permittee as specified below:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Monthly Average Daily Maximum	Per discharge	Calculated	FLW-11	See I.B.19
Oil and Grease	mg/L	Max Max	15.0 20.0	Monthly Average Daily Maximum	Per discharge	Grab	EFF-8	See I.B.19
Solids, Total Suspended	mg/L	Max Max	30.0 100.0	Monthly Average Daily Maximum	Per discharge	Grab	EFF-8	See I.B.19

Hydrazine	mg/L	Max	0.3	Daily Maximum	Per discharge	Grab	EFF-8	See I.B.19 and 20
pH	s.u.	Min Max	6.0 9.0	Daily Minimum Daily Maximum	Per discharge	Grab	EFF-8	See I.B.19

17. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.16 and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-11	Calculated based on water level depth over weir.
EFF-8	The stormwater treatment system effluent point prior to discharge to the discharge canal.

18. The discharge shall not contain components that settle to form putrescent deposits or float as debris, scum, oil, or other matter. *[62-302.500(1)(a)]*

19. Monitoring for this effluent is not required provided the first 15 minutes of a 10-year, 24-hour rainfall event is collected in the forwarding basin (Basin B-5) and routed to the percolation basin (Basin B-2). Subsequent storm water may be discharged without limitations or monitoring requirements.

20. The discharge limitation and monitoring requirements for hydrazine shall be applicable only during certain periods, i.e., accidental spill or any other event which could introduce hydrazine in concentrations in excess of 20 ug/L to an equipment area floor drain system.

C. **Land Application Systems**

1. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge process wastewater, boiler blowdown, reverse osmosis reject water, metal cleaning wastewater, and stormwater to **Land Application System R-001, Percolation Basin (Basin B-2)**. Such discharge shall be limited and monitored by the permittee as specified below:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Weekly Maximum Monthly Average	Weekly	Estimated	FLW-13	

2. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.C.1. and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-13	Treated wastewater flow entering Basin B-2.

3. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge stormwater, boiler blowdown, treated equipment area runoff, non-equipment area runoff, and treated miscellaneous service water rinses from the power block area to **Land Application System R-002, Stormwater Basin (Basin B-5)**. Such discharge shall be limited and monitored by the permittee as specified below:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Weekly Maximum Monthly Average	Weekly	Calculated	FLW-14	

4. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.C.3. and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-14	Treated wastewater flow entering Basin B-5.

D. Other Limitations and Monitoring and Reporting Requirements

1. The sample collection, analytical test methods, and method detection limits (MDLs) applicable to this permit shall be conducted using a sufficiently sensitive method to ensure compliance with applicable water quality standards and effluent limitations and shall be in accordance with Rule 62-4.246, Chapters 62-160 and 62-601, F.A.C., and 40 CFR 136, as appropriate. The list of Department established analytical methods, and corresponding MDLs (method detection limits) and PQLs (practical quantitation limits), which is titled "FAC 62-4 MDL/PQL Table (April 26, 2006)" is available at http://www.dep.state.fl.us/labs/library/index.htm. The MDLs and PQLs as described in this list shall constitute the minimum acceptable MDL/PQL values and the Department shall not accept results for which the laboratory's MDLs or PQLs are greater than those described above unless alternate MDLs and/or PQLs have been specifically approved by the Department for this permit. Any method included in the list may be used for reporting as long as it meets the following requirements:

   a. The laboratory's reported MDL and PQL values for the particular method must be equal or less than the corresponding method values specified in the Department's approved MDL and PQL list;

   b. The laboratory reported MDL for the specific parameter is less than or equal to the permit limit or the applicable water quality criteria, if any, stated in Chapter 62-302, F.A.C. Parameters that are listed as "report only" in the permit shall use methods that provide an MDL, which is equal to or less than the applicable water quality criteria stated in 62-302, F.A.C.; and

   c. If the MDLs for all methods available in the approved list are above the stated permit limit or applicable water quality criteria for that parameter, then the method with the lowest stated MDL shall be used.

   When the analytical results are below method detection or practical quantitation limits, the permittee shall report the actual laboratory MDL and/or PQL values for the analyses that were performed following the instructions on the applicable discharge monitoring report.

   Where necessary, the permittee may request approval of alternate methods or for alternative MDLs or PQLs for any approved analytical method. Approval of alternate laboratory MDLs or PQLs are not necessary if the laboratory reported MDLs and PQLs are less than or equal to the permit limit or the applicable water quality criteria, if any, stated in Chapter 62-302, F.A.C. Approval of an analytical method not included in the above-referenced list is not necessary if the analytical method is approved in accordance with 40 CFR 136 or deemed acceptable by the Department. *[62-4.246, 62-160]*

2. The permittee shall provide safe access points for obtaining representative influent and effluent samples which are required by this permit. *[62-620.320(6)]*

Monitoring requirements under this permit are effective on the first day of the second month following permit issuance. Until such time, the permittee shall continue to monitor and report in accordance with previously effective permit requirements, if any. During the period of operation authorized by this permit, the permittee shall complete and submit to the Department Discharge Monitoring Reports (DMRs) in accordance with the frequencies specified by the REPORT type (i.e. monthly, toxicity, quarterly, semiannual, annual, etc.) indicated on the DMR forms attached to this permit. Monitoring results for each monitoring period shall be submitted in accordance with the associated DMR due dates below. DMRs shall be submitted for each required monitoring period including months of no discharge.

REPORT Type on DMR	Monitoring Period	Due Date
Monthly or Toxicity	first day of month - last day of month	28th day of following month
Quarterly	January 1 - March 31 April 1 - June 30 July 1 - September 30 October 1 - December 31	April 28 July 28 October 28 January 28
Semiannual	January 1 - June 30 July 1 - December 30	July 28 January 28
Annual	January 1 - December 31	January 28

DMRs shall be submitted for each required monitoring period including months of no discharge. The permittee may submit either paper or electronic DMR form(s). If submitting paper DMR form(s), the permittee shall make copies of the attached DMR form(s). If submitting electronic DMR form(s), the permittee shall use a Department-approved electronic DMR system.

The permittee may submit either paper or electronic DMR forms. If submitting paper DMR forms, ~~T~~the permittee shall make copies of the attached DMR form(s), without altering the original format or content unless approved by the Department, and shall submit the completed DMR form(s) to the Department by the twenty-eighth (28th) of the month following the month of operation at the addresses specified below:

Florida Department of Environmental Protection
Wastewater Compliance Evaluation Section, Mail Station 3551
Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

And

Florida Department of Environmental Protection
Southeast District
400 N. Congress Avenue, Suite 200
West Palm Beach, FL 33401

[62-620.610(18)]

5. Unless specified otherwise in this permit, all reports and other information required by this permit, including 24-hour notifications, shall be submitted to or reported to, as appropriate, the Department's Southeast District Office at the address specified below:

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

   Phone Number - (561) 681-6600
   FAX Number - (561) 681-6755 (All FAX copies shall be followed by original copies.)

   [62-620.305]

6. All reports and other information shall be signed in accordance with the requirements of Rule 62-620.305, F.A.C. *[62-620.305]*

7. If there is no discharge from the facility on a day when the facility would normally sample, the sample shall be collected on the day of the next discharge. *[62-620.320(6)]*

8. The permittee is authorized to discharge from **Internal Outfalls I-181, I-182, I-183, and I-184 - Auxiliary Equipment Cooling and Outfall I019 - Intake Screen Washwater.** Sampling and monitoring of these outfalls are not required.

9. The permittee is authorized to discharge from **Outfalls I-1B2 - Stormwater From Diked Petroleum Storage or Handling Areas (North Tank Farm)**, provided such discharges are limited and monitored by the permittee as specified below:

   a. The facility shall have a valid Spill Prevention Control and Countermeasure (SPCC) Plan pursuant to 40 CFR Part 112.

   b. In draining the diked area, a portable oil skimmer or similar device or absorbent material shall be used to remove oil and grease (as indicated by the presence of a sheen) immediately prior to draining.

   c. Monitoring records shall be maintained in the form of a log and shall contain the following information, as a minimum:

      - Date and time of discharge;
      - Estimated volume of discharge;
      - Initials of person making visual inspection and authorizing discharge; and
      - Observed conditions of stormwater discharged.

   d. There shall be no discharge of floating solids or visible foam in other than trace amounts and no discharge of a visible oil sheen at any time.

10. The permittee shall continue compliance with the facility's Manatee Protection Plan approved by the Department on August 13, 1999 et seq.

11. The use of fluorescein dye at a feed concentration of no greater than 1.0 mg/L is authorized for maintenance and flow testing activities. The facility will maintain an on-site record of the dosage and discharge concentrations, specific application activity, flow rate, and residence time per usage to be available upon request. The dye may be used while other treatment chemicals are present in the water to be dosed.

12. The use of sodium hydroxide and sulfuric acid are authorized for pH control.

13. Sodium phosphate, used to control calcium and magnesium scaling, and ammonium hydroxide, used for pH control, are authorized as boiler water treatment additives.

14. Sodium metabisulfite is authorized for use in the facility's water treatment system for dechlorination of source water prior to being fed to the reverse osmosis (RO) system's membranes. The concentration of sodium metabisulfite in the RO feed water shall be 3 mg/L or less.

15. Discharge of any product registered under the Federal Insecticide, Fungicide, and Rodenticide Act to any waste stream which ultimately may be discharged to lakes, rivers, or other waters of the State is prohibited unless specifically authorized elsewhere in this permit. This requirement is not applicable to products used for lawn and agricultural purposes or to the use of herbicides if used in accordance with labeled instructions and any applicable State permit. Discharge of chlorine from the use of chlorine gas, sodium hypochlorite, or similar chlorination compounds for treatment of the plant potable and service water systems is authorized.

    A permit revision from the Department shall be required prior to the use of any biocide or chemical additive used in the cooling system (except chlorine or hydrazine as authorized elsewhere in this permit) or any other portion of the treatment system which may be toxic to aquatic life. The permit revision request shall include:
    a. Name and general composition of biocide or chemical
    b. Frequencies of use
    c. Quantities to be used
    d. Proposed effluent concentrations
    e. Acute and/or chronic toxicity data (laboratory reports shall be prepared according to Section 12 of EPA document no. EPA/600/4-90/027 entitled, <u>Methods for Measuring the Acute Toxicity of Effluents and Receiving</u>

<u>Waters for Freshwater and Marine Organisms</u>, or most current addition.)

f. Product data sheet
g. Product label

Herbicides may be used within basins for the purpose of prevention of over accumulation of aquatic weeds. Use shall be in accordance with labeled instructions. Not later than 90 days after the effective date of this permit, the permittee shall provide the Department with a list of all herbicides used in the previous twelve months. Other products shall not be used without prior approval.

16. Discharge of any waste resulting from the combustion of toxic, hazardous, or metal cleaning wastes to any waste stream which ultimately discharges to waters of the State is prohibited, unless specifically authorized elsewhere in this permit.

17. There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid. The permittee shall dispose of all known PCB equipment, articles, and wastes in accordance with 40 CFR 761. The permittee shall certify each time that this disposal has been accomplished.

18. There shall be no discharge of floating debris, scum, oil, or other matter in such amounts as to form nuisances or produce color, odor, taste, turbidity, or other conditions to such degree as to create a nuisance or otherwise interfere with the beneficial use of the receiving waters in accordance with Rules 62-302.500(1)(a) and 62-302.530(500)(b), F.A.C. Any such discharges to waters of the State shall be reported to the Department when submitting DMRs.

19. The permittee is authorized to use Nalco 7330 in both of the facility's closed cooling water systems (CCWS). For scheduled maintenance or repair activities requiring drainage of isolated piping and pumps, or complete or partial drainage of a CCWS, the permittee shall not apply Nalco 7330 to that CCWS less than 30 days prior to the scheduled outage. For unscheduled activities requiring immediate attention, such as emergency repairs, in which Nalco 7330 has been applied within the past 30 days, the discharge to stormwater basin B-5 shall be routed to percolation basin B-2, and not discharged via the alternate route through outfall I-01B1. If a discharge of Nalco 7330 containing wastewater from the stormwater forwarding sump S-11 to surface waters via outfall I-01B1 was necessary, toxicity testing and reporting shall be required in accordance with permit condition I.A.4, at the monitoring location designated as BFF-8 and described in permit condition I.A.13. The facility shall maintain a record on-site containing the frequency of use, feed concentration, discharge concentration, application dates, dates of scheduled and unscheduled maintenance and repair activities, volumes of wastewater discharged to the B-5 basin containing Nalco 7330, and route of discharge if applicable, for both CCWSs.

20. The permittee shall maintain the current intake through-screen velocity such that the existing maximum velocity is not exceeded.

II. SLUDGE MANAGEMENT REQUIREMENTS

A. Basic Management Requirements

1. The disposal of sludge or other solids generated from the plant's wastewater treatment and containment system shall be reused, reclaimed, or otherwise disposed of in accordance with the requirements of Chapter 62-701, F.A.C.

2. The permittee shall be responsible for proper treatment, management, use or land application of its sludges.

3. The permittee shall keep records of the amount of sludge or residuals disposed, transported, or incinerated in (Please specify units). If a person other than the permittee is responsible for sludge transporting, disposal, or incineration, the permittee shall also keep the following records:

   a. Name, address and telephone number of any transporter, and any manifests or bill of lading used;
   b. Name and location of the site of disposal, treatment or incineration;
   c. Name, address, and telephone number of the entity responsible for the disposal, treatment, or incineration site.

III. GROUND WATER REQUIREMENTS

1. The permittee shall give at least 72-hours notice to the Department's Southeast District Office, prior to the installation of any monitoring wells. *[62-620.320(6)]*

2. Prior to construction of ground water monitoring wells, a soil boring shall be made at each monitoring well location in order to properly determine the well depth and screen interval. *[62-520.900(2)]*

3. Within 30 days after installation of a monitoring well, the permittee shall submit to the Department's Southeast District Office detailed information on the well's location and construction on the attached DEP Form(s) 62-520.900(2), Monitor Well Completion Report. *[62-532.410 and 62-520.900(2)]*

4. All piezometers and monitoring wells not part of the approved ground water monitoring plan are to be plugged and abandoned in accordance with Rule 62-532.500(4), F.A.C., unless future use is intended. *[62-532.500(4)]*

5. For land application systems for R-001and R-002, all ground water quality criteria specified in Chapter 62-520, F.A.C., shall be met at the edge of the zone of discharge. The zone of discharge for this project shall extend horizontally to the facility's property line and vertically to the base of the surficial aquifer. *[62-520.200(26)] [62-522.200(10) and 62-520.465]*

6. The ground water minimum criteria specified in Rule 62-520.400 F.A.C., shall be met within the zone of discharge. *[62-520.400 and 62-520.420(4)]*

7. If the concentration for any constituent listed in Permit Condition III.10. in the natural background quality of the ground water is greater than the stated maximum, or in the case of pH is also less than the minimum, the representative background quality shall be the prevailing standard. *[62-520.420(2)]*

8. During the period of operation authorized by this permit, the permittee shall continue to sample ground water at the monitoring wells identified in Permit Condition III.9. below in accordance with this permit and the approved ground water monitoring plan prepared in accordance with Rule 62-520.600, F.A.C. *[62-520.600]*

9. The following monitoring wells shall be sampled for Land Application Systems R-001 and R-002 at Land Application Sites PER-1 and PER-2, respectively.

Monitoring Well ID	Alternate Well Name and/or Description of Monitoring Location	Latitude			Longitude			Depth (Feet)	Aquifer Monitored	New or Existing
		°	'	"	°	'	"			
MWB-01	Monitoring Well NOB-1; west of NW corner for B-1	26	04	59.8	80	07	32.1	23	Surficial	Existing
MWC-01	Monitoring Well NOB-2A; south of SE corner for B-3	26	04	57.5	80	07	35.4	15	Surficial	Existing
MWC-02	Monitoring Well NOB-2B; south of SE corner for B-3	26	04	57.4	80	07	35.3	25	Surficial	Existing
MWC-03	Monitoring Well NOB-3A (NOB-3A-R); south of overflow area for B-3	26	04	57.4	80	07	38.6	15	Surficial	Existing
MWC-04	Monitoring Well NOB-3B1; south of overflow area for B-3	26	04	57.4	80	07	38.5	25	Surficial	Existing
MWC-05	Monitoring Well D-1A; south of SE corner for B-1	26	04	58.3	80	07	27.7	15	Surficial	Existing

MWC = Compliance; MWB = Background; MWI = Intermediate; MWP =Piezometer

[62-520.600]

10. The following parameters shall be analyzed for each monitoring well identified in Permit Condition III.9. Results shall be reported on the permittee's Discharge Monitoring Report in accordance with Condition I.D.3. :

Parameter	Compliance Well Limit	Units	Sample Type	Monitoring Frequency
Water Level Relative to NGVD	Report	Feet	Measured	Quarterly
Solids, Total Dissolved (TDS)	Report	mg/L	Grab	Quarterly
pH	Report	s.u.	In Situ	Quarterly
Sulfate, Total	Report	mg/L	Grab	Quarterly
Iron, Total Recoverable	Report	mg/L	Grab	Quarterly
Manganese, Total Recoverable	Report	mg/L	Grab	Quarterly
Sodium, Total Recoverable	Report	mg/L	Grab	Quarterly
Fluoride, Total (as F)	4.0	mg/L	Grab	Semi-Annually
Arsenic, Total Recoverable	0.010	mg/L	Grab	Semi-Annually
Copper, Total Recoverable	Report	mg/L	Grab	Semi-Annually
Chromium, Total Recoverable	0.1	mg/L	Grab	Semi-Annually
Lead, Total Recoverable	0.015	mg/L	Grab	Semi-Annually
Nickel, Total Recoverable	0.1	mg/L	Grab	Semi-Annually
Silver, Total Recoverable	Report	mg/L	Grab	Semi-Annually
Zinc, Total Recoverable	Report	mg/L	Grab	Semi-Annually

[62-520.600(11)(b)]

11. Water levels shall be recorded before evacuating each well for sample collection. Elevation references shall include the top of the well casing and land surface at each well site (NAVD allowable) at a precision of plus or minus 0.01 foot. *[62-520.600(11)(c)]*

12. Ground water monitoring wells shall be purged prior to sampling to obtain representative samples. *[62-160.210]*

13. Analyses shall be conducted on unfiltered samples, unless filtered samples have been approved by the Department's Southeast District Office as being more representative of ground water conditions. *[62-520.310(5)]*

14. Ground water monitoring test results shall be submitted on Part D of Form 62-620.910(10) in accordance with Permit Condition I.D.3. *[62-520.600(11)(b)]*

15. If any monitoring well becomes damaged or inoperable, the permittee shall notify the Department's Southeast District Office immediately and a detailed written report shall follow within seven days. The written report shall detail what problem has occurred and remedial measures that have been taken to prevent recurrence. All monitoring well design and replacement shall be approved by the Department's Southeast District Office prior to installation. *[62-520.600][62-620.320(6)]*

16. An exemption from the Class G-II Ground Water Standard for sodium has been granted to the facility by the Department. The exemption is effective for the duration of this permit.

IV. ADDITIONAL LAND APPLICATION REQUIREMENTS

1. Appropriate warning signs shall be posted around the site boundaries to designate the nature of the various settling basins and percolation basins, including the designated overflow areas that comprised the permitted wastewater and stormwater treatment and disposal facility.

2. The bottoms for the settling basins and percolation basins shall be cleaned out periodically, or when necessary, to remove the excess buildup of sediments, and to ensure continuous percolation capability for the percolation basins. The sediments and sludge excavated from the basins must be properly stored onsite, until they are

disposed of in accordance with the requirements in Part II of the permit. Routine weed control and regular maintenance of basin embankments and access areas are required.

3. The permittee shall inspect the conditions for the impermeable liners for the lined settling basins and the percolation basins with lined side slopes. Any liners that display signs of significant deterioration, or evidence of leakage or instability, shall be replaced as soon as practical.

4. A minimum one (1) foot of freeboard should in general be maintained for all the wastewater and stormwater storage, treatment and percolation basins.

5. An existing land application system (R-001) consisting of percolation pond. Land application system R-001 is located approximately at latitude 26° 04' 59" N, longitude 80° 07' 32" W. R-001 is also identified as Percolation Basin B-2. It is located south of the plant switchyard with a dimension of approximately 112 feet long, 82 feet wide and 6.5 feet deep; approximate design capacity of 340,000 gallon; and built with lined side-slopes and a crushed limestone bottom. It is part of the facility's permitted metal cleaning waste/low volume waste treatment and disposal system. And being the downstream-most unit after a sequence of precipitation and settling treatment basins. In addition to handling treated waste streams originating from miscellaneous maintenance activities, non-equipment area runoff (as an alternate discharge route), R.O. water treatment system, metal cleaning waste, boiler process, and boiler blowdown (as an alternate discharge route), it also receives treated stormwater (equipment area runoff) pumped from Stormwater Forwarding Sump S-11. Basin B-2 has an overflow containment area approximately 185 feet by 84 feet by 247 feet by 80 feet. Depth is approximately 4 feet, with a design capacity of 500,000 gallons.

6. An existing land application system (R-002) consisting of percolation pond. Land application system R-002 is located approximately at latitude 26° 05' 00" N, longitude 80° 07' 28" W. R-002 is also identified as Stormwater Forwarding Basin (SWFB) B-5. It is located east of the plant switchyard with dimensions of approximately 282 feet long, 140 feet wide and 7.5 feet deep; a design capacity of approximately 326,000 gallons; and built with lined side-slopes and a crushed limestone bottom. It receives stormwater and miscellaneous plant washdown water from both equipment (primarily the "power block" area) and non-equipment areas. Equipment area runoff is routed through oil/water separators prior to entering Stormwater Forwarding Sump S-11. Boiler blowdown via equipment or non-equipment runoff areas may be a contributing source of wastewater as an alternate discharge route. Excess stormwater entering Sump S-11 may also be diverted to the plant discharge canal via outfall I-01B1 when the system capacity is exceeded.

7. Actual flows into the basins are likely affected by the prevailing weather condition and occurrence of plant maintenance activities. FPL has projected in a report dated May 8, 1991, the percolation capacity for Percolation Basin at 23,700 gpd. At this time, the permitted disposal capacities for the two basins are restricted by their actual demonstrated percolation capabilities instead of other imposed numerical limits. The permitted land application system also includes overflows areas adjacent to Percolation Basin B-2, and that south of Solids Settling Basin (SSB) Basin B-3, that may be utilized in extreme wet weather. Basin B-2 has an overflow containment area approximately 185 feet by 84 feet by 247 feet by 80 feet. Depth is approximately 4 feet, with a design capacity of 500,000 gallons. Basin B-3 has an overflow containment area approximately 233 feet by 261 feet by 162 feet and triangular in shape. Depth is approximately 3 feet with a design capacity of approximately 356,000 gallons.

V. OPERATION AND MAINTENANCE REQUIREMENTS

1. During the period of operation authorized by this permit, the wastewater facilities shall be operated under the supervision of a person who is qualified by formal training and/or practical experience in the field of water pollution control. *[62-620.320(6)]*

2. The permittee shall maintain the following records and make them available for inspection on the site of the permitted facility.

   a. Records of all compliance monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, including, if applicable, a copy of the laboratory certification showing the certification number of the laboratory, for at least three years from the date the sample or measurement was taken;

b. Copies of all reports required by the permit for at least three years from the date the report was prepared;
c. Records of all data, including reports and documents, used to complete the application for the permit for at least three years from the date the application was filed;
d. A copy of the current permit;
e. A copy of any required record drawings; and
f. Copies of the logs and schedules showing plant operations and equipment maintenance for three years from the date of the logs or schedules.

[62-620.350]

VI. SCHEDULES

1. The following improvement actions shall be completed according to the following schedule.

Improvement Action	Completion Date
1. The permittee shall identify and submit the location of background sampling point SWB-1 within 30 days of permit issuance. The sampling point location shall be approved of by the Department's Southeast District Office. The point shall be upstream (north) of outfalls I-012 and I-016.	30 days from permit issuance.

[62-620.320(6)]

2. The following improvement actions shall be completed according to the following schedule. The Storm water Pollution Prevention Plan (SWPPP) shall be prepared and implemented in accordance with Part VII of this permit.

Improvement Action	Completion Date
1. Develop and implement SWPPP	18 months from permit issuance.
2. Complete Plan Summary	2 years from permit issuance.
3. Progress/Update Report	3 years, and then annual thereafter.

[62-620.320(6)]

3. If the permittee wishes to continue operation of this wastewater facility after the expiration date of this permit, the permittee shall submit an application for renewal no later than one-hundred and eighty days (180) prior to the expiration date of this permit. Application shall be made using the appropriate forms listed in Rule 62-620.910, F.A.C., including submittal of the appropriate processing fee set forth in Rule 62-4.050, F.A.C. *[62-620.335(1) and (2)]*

4. The permittee shall submit a copy of the Manatee Protection Plan, including any amendments, with the permit renewal application to each of the following agencies no later than one-hundred and eighty days (180) prior to the expiration date of this permit:

Florida Department of Environmental Protection
Industrial Wastewater Section, Mail Station 3545
Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Florida Fish and Wildlife Conservation Commission
Bureau of Protected Species Management
620 South Meridian Street
OES-BPS
Tallahassee, Florida 32399-1600

And

US Fish and Wildlife Service
Jacksonville Field Office
7915 Baymeadows Way, Suite 200
Jacksonville, Florida 32256-7517

5. No later than two months after the issuance date of this permit, the permittee shall submit to the Department representative pump curves for each pump associated with Units 1, 2, 3, and 4 that shows the pump performance curve, the system head curve, and the intersection of the two curves.

6. Within six months of the effective date of this permit, the permittee shall schedule a meeting with the Department to discuss the contents of the aquatic organism return plan in accordance with Condition I.B.15 and shall submit the plan to the Department within 12 months of the effective date of this permit. The plan shall be implemented within 24 months subsequent to approval by the Department.

VII. STORMWATER POLLUTION PREVENTION PLAN (SWPPP)

1. General Requirements

In accordance with Section 304(e) and 402(a)(2) of the Clean Water Act (CWA) as amended, 33 U.S.C. §§ 1251 et seq., and the Pollution Prevention Act of 1990, 42 U.S.C. §§ 13101-13109, the permittee must develop and implement a plan for utilizing practices incorporating pollution prevention measures. References to be considered in developing the plan are "Criteria and Standards for Best Management Practices Authorized Under Section 304(e) of the Act," found at 40 CFR 122.44 Subpart K and the Storm Water Management Industrial Activities Guidance Manual, EPA/833-R92-002 and other EPA documents relating to Best Management Practice guidance.

a. Definitions
(1) The term "pollutants" refers to conventional, non-conventional and toxic pollutants.
(2) Conventional pollutants are: biochemical oxygen demand (BOD), suspended solids, pH, fecal coliform bacteria and oil & grease.
(3) Non-conventional pollutants are those which are not defined as conventional or toxic.
(4) Toxic pollutants include, but are not limited to: (a) any toxic substance listed in Section 307(a)(1) of the CWA, any hazardous substance listed in Section 311 of the CWA, or chemical listed in Section 313(c) of the Superfund Amendments and Reauthorization Act of 1986; and (b) any substance (that is not also a conventional or non-conventional pollutant except ammonia) for which EPA has published an acute or chronic toxicity criterion.
(5) "Significant Materials" is defined as raw materials; fuels; materials such as solvents and detergents; hazardous substances designated under Section 101(14) of CERCLA; and any chemical the facility is required to report pursuant to EPCRA, Section 313; fertilizers; pesticides; and waste products such as ashes, slag and sludge.
(6) "Pollution prevention" and "waste minimization" refer to the first two categories of EPA's preferred hazardous waste management strategy: first, source reduction and then, recycling.
(7) "Recycle/Reuse" is defined as the minimization of waste generation by recovering and reprocessing usable products that might otherwise become waste; or the reuse or reprocessing of usable waste products in place of the original stock, or for other purposes such as material recovery, material regeneration or energy production.
(8) "Source reduction" means any practice which: (a) reduces the amount of any pollutant entering a waste stream or otherwise released into the environment (including fugitive emissions) prior to recycling, treatment or disposal; and (b) reduces the hazards to public health and the environment associated with the release of such pollutant. The term includes equipment or technology modifications, process or procedure modifications, reformulation or redesign of products, substitution of raw materials, and improvements in housekeeping, maintenance, training, or inventory control. It does not include any practice which alters the physical, chemical, or biological characteristics or the volume of a pollutant through a process or activity which itself is not integral to, or previously considered necessary for, the production of a product or the providing of a service.

(9) "SWPPP" means a Storm Water Pollution Prevention Plan incorporating the requirements of 40 CFR § 125, Subpart K, plus pollution prevention techniques, except where other existing programs are deemed equivalent by the permittee. The permittee shall certify the equivalency of the other referenced programs.

(10) The term "material" refers to chemicals or chemical products used in any plant operation (i.e., caustic soda, hydrazine, degreasing agents, paint solvents, etc.). It does not include lumber, boxes, packing materials, etc.

2. Storm Water Pollution Prevention Plan

The permittee shall develop and implement a SWPPP for the facility, which is the source of wastewater and storm water discharges, covered by this permit. The plan shall be directed toward reducing those pollutants of concern which discharge to surface waters and shall be prepared in accordance with good engineering and good housekeeping practices. For the purposes of this permit, pollutants of concern shall be limited to toxic pollutants, as defined above, known to the discharger. The plan shall address all activities which could or do contribute these pollutants to the surface water discharge, including process, treatment, and ancillary activities.

a. Signatory Authority & Management Responsibilities

The SWPPP shall be signed by permittee or their duly authorized representative in accordance with rule 62-620.305(2)(a) and (b). The SWPPP shall be reviewed by plant environmental/engineering staff and plant manager. Where required by Chapter 471-(P.E.) or Chapter 492 (P.G.) Florida Statutes, applicable portions of the SWPPP shall be signed and sealed by the professional(s) who prepared them.

A copy of the plan shall be retained at the facility and shall be made available to the permit issuing authority upon request.

The SWPPP shall contain a written statement from corporate or plant management indicating management's commitment to the goals of the BMP program. Such statements shall be publicized or made known to all facility employees. Management shall also provide training for the individuals responsible for implementing the SWPPP.

b. SWPPP Requirements

(1) A topographic map extending one-quarter mile beyond the property boundaries of the facility, showing: the facility, surface water bodies, wells (including injection wells), seepage pits, infiltration ponds, and the discharge points where the facility's storm water discharges to a municipal storm drain system or other water body. The requirements of this paragraph may be included on the site map if appropriate.

(2) A site map showing:
- (a) The storm water conveyance and discharge structures;
- (b) An outline of the storm water drainage areas for each storm water discharge point;
- (c) Paved areas and buildings;
- (d) Areas used for outdoor manufacturing, storage, or disposal of significant materials, including activities that generate significant quantities of dust or particulates;
- (e) Location of existing or future storm water structural control measures/practices (dikes, coverings, detention facilities, etc.);
- (f) Surface water locations and/or municipal storm drain locations;
- (g) Areas of existing and potential soil erosion;
- (h) Vehicle service areas; and
- (i) Material loading, unloading, and access areas.

(3) A narrative description of the following:
- (a) The nature of the industrial activities conducted at the site, including a description of significant materials that are treated, stored or disposed of in a manner to allow exposure to storm water;
- (b) Materials, equipment, and vehicle management practices employed to minimize contact of significant materials with storm water discharges;
- (c) Existing or future structural and non-structural control measures/practices to reduce pollutants in storm water discharges;
- (d) Industrial storm water discharge treatment facilities;

(e) Methods of onsite storage and disposal of significant materials;
(f) Overall objectives (both short-term and long-term) and scope of the plan, specific reduction goals for pollutants, anticipated dates of achievement of reduction, and a description of means for achieving each reduction goal;
(g) A description of procedures relative to spill prevention, control & countermeasures and a description of measures employed to prevent storm water contamination;
(h) A description of practices involving preventive maintenance, housekeeping, recordkeeping, inspections, and plant security; and
(i) The description of a waste minimization assessment performed in accordance with the conditions outlined in condition c below, results of the assessment, and a schedule for implementation of specific waste reduction practices.

(4) A list of the types of pollutants that have a reasonable potential to be present in storm water discharges in significant quantities.

(5) An estimate of the size of the facility in acres or square feet, and the percent of the facility that has impervious areas such as pavement or buildings.

(6) A summary of existing sampling data describing pollutants in storm water discharges.

c. Waste Minimization Assessment

The permittee is encouraged but not required to conduct a waste minimization assessment (WMA) for this facility to determine actions that could be taken to reduce waste loading and chemical losses to all wastewater and/or storm water streams as described in Part VII.D.2 of this permit.

If the permittee elects to develop and implement a WMA, information on plan components can be obtained forms the Department's Industrial Wastewater website, or from:

Florida Department of Environmental Protection
Industrial Wastewater Section, Mail Station 3545
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
(850) 245-8589
(850) 245-8669 – Fax

d. Pollution Prevention Committee:

A pollution prevention committee within the plant organization shall be appointed. These members shall be responsible for developing the SWPPP and assisting the plant manager in its implementation, maintenance, and revision.

e. Employee Training

(1) The permittee shall describe the storm water employee training program for the facility. The description shall include the topics to be covered, such as spill response, good housekeeping and material management practices, and shall identify periodic dates (e.g., every 6 months during the months of July and January) for such training. The permittee shall provide employee training for all employees and contractors that work in areas where industrial materials or activities are exposed to storm water, and for employees that are responsible for implementing activities identified in the SWPPP (*e.g.*, inspectors, maintenance people). The employee training shall inform facility personnel and contractors of the components and goals of the facility SWPPP.

(2) Each employee and contractor that works in an areas where industrial materials or activities are exposed to storm water, and each employee that is responsible for implementing activities identified in the SWPPP shall undergo training at least once a year. Training records shall include trainee's name, signature, date of training and topics covered. Records shall be retained on-site for a minimum of three years.

f. Plan Development & Implementation

(1) The SWPPP shall be developed and implemented 18 months after the effective date of this permit, unless any later dates are specified in this permit. Any portion of the SWPPP which is ongoing at the time of development or implementation shall be described in the plan. Any waste reduction practice which is recommended for implementation over a period of time shall be identified in the plan, including a schedule for its implementation.

(2) The personnel named in the SWPPP shall perform and document a quarterly visual observation of a storm water discharge associated with industrial activity from each outfall. The visual observation shall be made during daylight hours. If no storm event resulted in runoff during daylight hours from the facility during a monitoring quarter, the permittee is excused from the visual observation requirement for that quarter, provided the permittee documents in their records that no runoff occurred. The permittee shall sign and certify the documentation.

(3) The personnel named in the SWPPP shall conduct visual observations on samples collected as soon as practical, but not to exceed 1 hour of when the runoff begins discharging from the facility. All samples must be collected from a storm event discharge that is greater than 0.1 inch in magnitude and that occurs at least 72 hours from the previously measurable (greater than 0.1 inch rainfall) storm event. The observation shall document: color, odor, clarity, floating solids, settled solids, suspended solids, foam, oil sheen, and other obvious indicators of storm water pollution.

(4) The permittee shall maintain visual observation reports onsite with the SWPPP for a minimum of three years. The report must include the observation date and time, inspection personnel, nature of the discharge (i.e., runoff), visual quality of the storm water discharge (including observations of color, odor, clarity, floating solids, settled solids, suspended solids, foam, oil sheen, and other obvious indicators of storm water pollution), and probable sources of any observed storm water contamination.

(5) At least once a year the personnel named in the SWPPP shall verify that the description of potential pollutant sources required under this permit is accurate; the site map as required in the SWPPP has been updated or otherwise modified to reflect current conditions; and the controls to reduce pollutants in storm water discharges associated with industrial activity identified in the SWPPP are being implemented and are adequate.

g. Submission of Plan Summary & Progress/Update Reports

(1) Plan Summary: Not later than 2 years after the effective date of the permit, a summary of the SWPPP shall be developed and maintained at the facility and made available to the permit issuing authority upon request. The summary should include the following: a brief description of the plan, its implementation process, schedules for implementing identified waste reduction practices, and a list of all waste reduction practices being employed at the facility. The results of waste minimization assessment studies already completed as well as any scheduled or ongoing WMA studies shall be discussed.

(2) Progress/Update Reports: Annually thereafter for the duration of the permit progress/update reports documenting implementation of the plan shall be maintained at the facility and made available to the permit issuing authority upon request. The reports shall discuss whether or not implementation schedules were met and revise any schedules, as necessary. The plan shall also be updated as necessary and the attainment or progress made toward specific pollutant reduction targets documented. Results of any ongoing WMA studies as well as any additional schedules for implementation of waste reduction practices shall be included.

(3) A timetable for the various plan requirements follows:

Timetable for SWPPP Requirements:

REQUIREMENT	TIME FROM EFFECTIVE DATE OF THIS PERMIT
Complete SWPPP	18 months
Complete Plan Summary	2 years
Progress/Update Reports	3 years, and then annually thereafter

The permittee shall maintain the plan and subsequent reports at the facility and shall make the plan available to the Department upon request.

h. Plan Review & Modification

If following review by the Department, the SWPPP is determined insufficient, the permittee will be notified that the SWPPP does not meet one or more of the minimum requirements of this Part. Upon such notification from the Department, the permittee shall amend the plan and shall submit to the Department a written certification that the requested changes have been made. Unless otherwise provided by the Department, the permittee shall have 30 days after such notification to make the changes necessary.

The permittee shall modify the SWPPP whenever there is a change in design, construction, operation, or maintenance, which has a significant effect on the potential for the discharge of pollutants to waters of the State or if the plan proves to be ineffective in achieving the general objectives of reducing pollutants in wastewater or storm water discharges. Modifications to the plan may be reviewed by the Department in the same manner as described above.

The permittee may incorporate applicable portions of plans prepared for other purposes. Plans or portions of plans incorporated into a SWPPP become enforceable requirements of this permit.

VIII. OTHER SPECIFIC CONDITIONS

A. Specific Conditions Applicable to All Permits

1. Where required by Chapter 471 or Chapter 492, F.S., applicable portions of reports that must be submitted under this permit shall be signed and sealed by a professional engineer or a professional geologist, as appropriate. *[62-620.310(4)]*

2. The permittee shall provide verbal notice to the Department's Southeast District Office as soon as practical after discovery of a sinkhole or other karst feature within an area for the management or application of wastewater, or wastewater sludges. The permittee shall immediately implement measures appropriate to control the entry of contaminants, and shall detail these measures to the Department's Southeast District Office in a written report within 7 days of the sinkhole discovery. *[62-620.320(6)]*

B. Specific Conditions Related to Construction

This section is not applicable to this facility.

C. Specific Conditions Related to Existing Manufacturing, Commercial, Mining, and Silviculture Wastewater Facilities or Activities

1. Existing manufacturing, commercial, mining, and silvicultural wastewater facilities or activities that discharge into surface waters shall notify the Department as soon as they know or have reason to believe:

   a. That any activity has occurred or will occur which would result in the discharge, on a routine or frequent basis, of any toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following levels;
      (1) One hundred micrograms per liter,
      (2) Two hundred micrograms per liter for acrolein and acrylonitrile; five hundred micrograms per liter for 2, 4-dinitrophenol and for 2-methyl-4, 6-dinitrophenol; and one milligram per liter for antimony, or
      (3) Five times the maximum concentration value reported for that pollutant in the permit application; or

   b. That any activity has occurred or will occur which would result in any discharge, on a non-routine or infrequent basis, of a toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following levels;
      (1) Five hundred micrograms per liter,
      (2) One milligram per liter for antimony, or
      (3) Ten times the maximum concentration value reported for that pollutant in the permit application.

   [62-620.625(1)]

D. Reopener Clauses

1. The permit shall be revised, or alternatively, revoked and reissued in accordance with the provisions contained in Rules 62-620.325 and 62-620.345 F.A.C., if applicable, or to comply with any applicable effluent standard or limitation issued or approved under Sections 301(b)(2)(C) and (D), 304(b)(2) and 307(a)(2) of the Clean Water Act (the Act), as amended, if the effluent standards, limitations, or water quality standards so issued or approved:

   a. Contains different conditions or is otherwise more stringent than any condition in the permit/or;

   b. Controls any pollutant not addressed in the permit.

   The permit as revised or reissued under this paragraph shall contain any other requirements then applicable.

2. The permit may be reopened to adjust effluent limitations or monitoring requirements should future Water Quality Based Effluent Limitation determinations, water quality studies, DEP approved changes in water quality standards, EPA established Total Maximum Daily Loads (TMDLs), or other information show a need for a different limitation or monitoring requirement.

3. The Department or EPA may develop a TMDL during the life of the permit. Once a TMDL has been established and adopted by rule, the Department shall revise this permit to incorporate the final findings of the TMDL.

4. The permit shall be reopened for revision as appropriate to address new information that was not available at the time of this permit issuance or to comply with requirements of new regulations, standards, or judicial decisions relating to CWA 316(b).

E. Duty to Reapply

1. The Permittee is not authorized to discharge to waters of the State after the expiration date of this permit, unless:

   a. the Permittee has applied for renewal of this permit at least 180 days before the expiration date (January 22, 2015) using the appropriate forms listed in Rule 62-620.910, F.A.C., and in the manner established in the Department of Environmental Protection Guide to Permitting Wastewater Facilities or Activities Under Chapter 62-620, F.A.C., including submittal of the appropriate processing fee set forth in Rule 62-4.050, F.A.C.; or

   b. the Permittee has made complete the application for renewal of this permit before the permit expiration date.

   [62-620.335(1)-(4), F.A.C.]

2. When publishing Notice of Draft and Notice of Intent in accordance with Rules 62-110.106 and 62-620.550, F.A.C., the permittee shall publish the notice at its expense in a newspaper of general circulation in the county or counties in which the activity is to take place either

   a. Within thirty days after the permittee has received a notice; or
   b. Within thirty days after final agency action.

   Failure to publish a notice is a violation of this permit.

IX. GENERAL CONDITIONS

1. The terms, conditions, requirements, limitations and restrictions set forth in this permit are binding and enforceable pursuant to Chapter 403, Florida Statutes. Any permit noncompliance constitutes a violation of Chapter 403, Florida Statutes, and is grounds for enforcement action, permit termination, permit revocation and reissuance, or permit revision. *[62-620.610(1)]*

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviations from the approved drawings, exhibits, specifications or

conditions of this permit constitutes grounds for revocation and enforcement action by the Department. *[62-620.610(2)]*

3. As provided in Subsection 403.087(6), F.S., the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor authorize any infringement of federal, state, or local laws or regulations. This permit is not a waiver of or approval of any other Department permit or authorization that may be required for other aspects of the total project which are not addressed in this permit. *[62-620.610(3)]*

4. This permit conveys no title to land or water, does not constitute state recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title. *[62-620.610(4)]*

5. This permit does not relieve the permittee from liability and penalties for harm or injury to human health or welfare, animal or plant life, or property caused by the construction or operation of this permitted source; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department. The permittee shall take all reasonable steps to minimize or prevent any discharge, reuse of reclaimed water, or residuals use or disposal in violation of this permit which has a reasonable likelihood of adversely affecting human health or the environment. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. *[62-620.610(5)]*

6. If the permittee wishes to continue an activity regulated by this permit after its expiration date, the permittee shall apply for and obtain a new permit. *[62-620.610(6)]*

7. The permittee shall at all times properly operate and maintain the facility and systems of treatment and control, and related appurtenances, that are installed and used by the permittee to achieve compliance with the conditions of this permit. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to maintain or achieve compliance with the conditions of the permit. *[62-620.610(7)]*

8. This permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit revision, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance does not stay any permit condition. *[62-620.610(8)]*

9. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, including an authorized representative of the Department and authorized EPA personnel, when applicable, upon presentation of credentials or other documents as may be required by law, and at reasonable times, depending upon the nature of the concern being investigated, to:

   a. Enter upon the permittee's premises where a regulated facility, system, or activity is located or conducted, or where records shall be kept under the conditions of this permit;
   b. Have access to and copy any records that shall be kept under the conditions of this permit;
   c. Inspect the facilities, equipment, practices, or operations regulated or required under this permit; and
   d. Sample or monitor any substances or parameters at any location necessary to assure compliance with this permit or Department rules.

   [62-620.610(9)]

10. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data, and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except as such use is proscribed by Section 403.111, F.S., or Rule 62-620.302, F.A.C. Such evidence shall only be used to the extent that it is consistent with the Florida Rules of Civil Procedure and applicable evidentiary rules. *[62-620.610(10)]*

11. When requested by the Department, the permittee shall within a reasonable time provide any information required by law which is needed to determine whether there is cause for revising, revoking and reissuing, or

terminating this permit, or to determine compliance with the permit. The permittee shall also provide to the Department upon request copies of records required by this permit to be kept. If the permittee becomes aware of relevant facts that were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be promptly submitted or corrections promptly reported to the Department. *[62-620.610(11)]*

12. Unless specifically stated otherwise in Department rules, the permittee, in accepting this permit, agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance; provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules. A reasonable time for compliance with a new or amended surface water quality standard, other than those standards addressed in Rule 62-302.500, F.A.C., shall include a reasonable time to obtain or be denied a mixing zone for the new or amended standard. *[62-620.610(12)]*

13. The permittee, in accepting this permit, agrees to pay the applicable regulatory program and surveillance fee in accordance with Rule 62-4.052, F.A.C. *[62-620.610(13)]*

14. This permit is transferable only upon Department approval in accordance with Rule 62-620.340, F.A.C. The permittee shall be liable for any noncompliance of the permitted activity until the transfer is approved by the Department. *[62-620.610(14)]*

15. The permittee shall give the Department written notice at least 60 days before inactivation or abandonment of a wastewater facility or activity and shall specify what steps will be taken to safeguard public health and safety during and following inactivation or abandonment. *[62-620.610(15)]*

16. The permittee shall apply for a revision to the Department permit in accordance with Rules 62-620.300, F.A.C., and the Department of Environmental Protection Guide to Permitting Wastewater Facilities or Activities Under Chapter 62-620, F.A.C., at least 90 days before construction of any planned substantial modifications to the permitted facility is to commence or with Rule 62-620.325(2), F.A.C., for minor modifications to the permitted facility. A revised permit shall be obtained before construction begins except as provided in Rule 62-620.300, F.A.C. *[62-620.610(16)]*

17. The permittee shall give advance notice to the Department of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements. The permittee shall be responsible for any and all damages which may result from the changes and may be subject to enforcement action by the Department for penalties or revocation of this permit. The notice shall include the following information:

    a. A description of the anticipated noncompliance;
    b. The period of the anticipated noncompliance, including dates and times; and
    c. Steps being taken to prevent future occurrence of the noncompliance.

    [62-620.610(17)]

18. Sampling and monitoring data shall be collected and analyzed in accordance with Rule 62-4.246 and Chapters 62-160, 62-601, and 62-610, F.A.C., and 40 CFR 136, as appropriate.

    a. Monitoring results shall be reported at the intervals specified elsewhere in this permit and shall be reported on a Discharge Monitoring Report (DMR), DEP Form 62-620.910(10), or as specified elsewhere in the permit.

    b. If the permittee monitors any contaminant more frequently than required by the permit, using Department approved test procedures, the results of this monitoring shall be included in the calculation and reporting of the data submitted in the DMR.

    c. Calculations for all limitations which require averaging of measurements shall use an arithmetic mean unless otherwise specified in this permit.

    d. Except as specifically provided in Rule 62-160.300, F.A.C., any laboratory test required by this permit shall be performed by a laboratory that has been certified by the Department of Health Environmental Laboratory Certification Program (DOH ELCP). Such certification shall be for the matrix, test method and analyte(s) being measured to comply with this permit. For domestic wastewater facilities, testing for parameters listed in Rule 62-160.300(4), F.A.C., shall be conducted under the direction of a certified operator.

e. Field activities including on-site tests and sample collection shall follow the applicable standard operating procedures described in DEP-SOP-001/01 adopted by reference in Chapter 62-160, F.A.C.

f. Alternate field procedures and laboratory methods may be used where they have been approved in accordance with Rules 62-160.220, and 62-160.330, F.A.C.

[62-620.610(18)]

19. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule detailed elsewhere in this permit shall be submitted no later than 14 days following each schedule date. *[62-620.610(19)]*

20. The permittee shall report to the Department's Tallahassee any noncompliance which may endanger health or the environment. Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided within five days of the time the permittee becomes aware of the circumstances. The written submission shall contain: a description of the noncompliance and its cause; the period of noncompliance including exact dates and time, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

a. The following shall be included as information which must be reported within 24 hours under this condition:
   (1) Any unanticipated bypass which causes any reclaimed water or effluent to exceed any permit limitation or results in an unpermitted discharge,
   (2) Any upset which causes any reclaimed water or the effluent to exceed any limitation in the permit,
   (3) Violation of a maximum daily discharge limitation for any of the pollutants specifically listed in the permit for such notice, and
   (4) Any unauthorized discharge to surface or ground waters.

b. Oral reports as required by this subsection shall be provided as follows:
   (1) For unauthorized releases or spills of treated or untreated wastewater reported pursuant to subparagraph (a)4. that are in excess of 1,000 gallons per incident, or where information indicates that public health or the environment will be endangered, oral reports shall be provided to the STATE WARNING POINT TOLL FREE NUMBER (800) 320-0519, as soon as practical, but no later than 24 hours from the time the permittee becomes aware of the discharge. The permittee, to the extent known, shall provide the following information to the State Warning Point:
      (a) Name, address, and telephone number of person reporting;
      (b) Name, address, and telephone number of permittee or responsible person for the discharge;
      (c) Date and time of the discharge and status of discharge (ongoing or ceased);
      (d) Characteristics of the wastewater spilled or released (untreated or treated, industrial or domestic wastewater);
      (e) Estimated amount of the discharge;
      (f) Location or address of the discharge;
      (g) Source and cause of the discharge;
      (h) Whether the discharge was contained on-site, and cleanup actions taken to date;
      (i) Description of area affected by the discharge, including name of water body affected, if any; and
      (j) Other persons or agencies contacted.
   (2) Oral reports, not otherwise required to be provided pursuant to subparagraph b.1 above, shall be provided to the Department's Tallahassee within 24 hours from the time the permittee becomes aware of the circumstances.

c. If the oral report has been received within 24 hours, the noncompliance has been corrected, and the noncompliance did not endanger health or the environment, the Department's Tallahassee shall waive the written report.

[62-620.610(20)]

21. The permittee shall report all instances of noncompliance not reported under Permit Conditions IX. 17, 18 or 19 of this permit at the time monitoring reports are submitted. This report shall contain the same information required by Permit Condition IX.20 of this permit. *[62-620.610(21)]*

22. Bypass Provisions.

    a. "Bypass" means the intentional diversion of waste streams from any portion of a treatment works.

    b. Bypass is prohibited, and the Department may take enforcement action against a permittee for bypass, unless the permittee affirmatively demonstrates that:
       (1) Bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and
       (2) There were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if adequate back-up equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass which occurred during normal periods of equipment downtime or preventive maintenance; and
       (3) The permittee submitted notices as required under Permit Condition IX. 22. b. of this permit.

    c. If the permittee knows in advance of the need for a bypass, it shall submit prior notice to the Department, if possible at least 10 days before the date of the bypass. The permittee shall submit notice of an unanticipated bypass within 24 hours of learning about the bypass as required in Permit Condition IX. 20. of this permit. A notice shall include a description of the bypass and its cause; the period of the bypass, including exact dates and times; if the bypass has not been corrected, the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence of the bypass.

    d. The Department shall approve an anticipated bypass, after considering its adverse effect, if the permittee demonstrates that it will meet the three conditions listed in Permit Condition IX. 22. a. 1 through 3 of this permit.

    e. A permittee may allow any bypass to occur which does not cause reclaimed water or effluent limitations to be exceeded if it is for essential maintenance to assure efficient operation. These bypasses are not subject to the provisions of Permit Condition IX. 22. a. through c. of this permit.

    [62-620.610(22)]

23. Upset Provisions.

    a. "Upset" means an exceptional incident in which there is unintentional and temporary noncompliance with technology-based effluent limitations because of factors beyond the reasonable control of the permittee.
       (1) An upset does not include noncompliance caused by operational error, improperly designed treatment facilities, inadequate treatment facilities, lack of preventive maintenance, careless or improper operation.
       (2) An upset constitutes an affirmative defense to an action brought for noncompliance with technology based permit effluent limitations if the requirements of upset provisions of Rule 62-620.610, F.A.C., are met.

    b. A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed contemporaneous operating logs, or other relevant evidence that:
       (1) An upset occurred and that the permittee can identify the cause(s) of the upset;
       (2) The permitted facility was at the time being properly operated;
       (3) The permittee submitted notice of the upset as required in Permit Condition IX.5. of this permit; and
       (4) The permittee complied with any remedial measures required under Permit Condition IX. 5. of this permit.

    c. In any enforcement proceeding, the burden of proof for establishing the occurrence of an upset rests with the permittee.

    d. Before an enforcement proceeding is instituted, no representation made during the Department review of a claim that noncompliance was caused by an upset is final agency action subject to judicial review.

    [62-620.610(23)]

PERMITTEE: Florida Power and Light
FACILITY: Port Everglades Power Plant

PERMIT NUMBER: FL0001538 (Major)
EXPIRATION DATE: July 21, 2015

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENTOF
ENVIRONMENTAL PROTECTION

Janet G. Llewellyn
Director
Division of Water Resource Management
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
(850) 245-8336

Attachment(s):
Discharge Monitoring Report
Monitor Well Completion Report

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 110007-EI EXHIBIT 11

PARTY FLORIDA POWER & LIGHT CO. (DIRECT)

DESCRIPTION R. R. LAUBAUVE (RRL-6)

DATE 11/01/11

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 JJJJJJ 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 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.

* * * * *

(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 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), 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.

* * * * *

(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 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.

$$HCl=\sum_{i=1}^{n}(Ci90\times Qi\times 1.028) \quad \text{(Eq. 10)}$$

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.

$$Mercury=\sum_{i=1}^{n}(Hgi90\times Qi) \quad \text{(Eq. 11)}$$

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:

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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.

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FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI EXHIBIT 12
PARTY FLORIDA POWER & LIGHT CO. (DIRECT)
DESCRIPTION R. R. LAUBAUVE (RRL-7)
DATE 11/01/11

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.

* * * * *

(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.

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(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.

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(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.

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(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.

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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 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

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.

$$P_{90} = mean + (SD * t) \quad \text{(Eq. 1)}$$

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.

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FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 110007-EI EXHIBIT 13

PARTY FLORIDA POWER & LIGHT CO. (DIRECT)

DESCRIPTION R. R. LAUBAUVE (RRL-8)

DATE 11/01/11

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 lates, 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]

BILLING CODE 6560–50–P

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
6.0 References

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI EXHIBIT 14
PARTY FLORIDA POWER & LIGHT CO. (DIRECT)
DESCRIPTION R. R. LAUBAUVE (RRL-9)
DATE 11/01/11

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.

$$\text{Annual Tune-up Cost (\$2008)} = \{[C_{\$2004} * (X_{2008} / X_{2004}) * i * (1+i)^y] / [(1+i)^y - 1)]\} + [Z_{\$2004} * (X_{2008} / X_{2004})] = \$2{,}875 \qquad \textbf{(Equation 1)}$$

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%

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 Catalyst	Activated Carbon Injection	Work Practice 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 SO_2 equivalent to the reduction in HCl. The logic for estimating SO_2 reductions is a change since the proposal of the rule, to address public comments concerned with overestimating SO_2 reductions. At proposal we had estimated that all units installing control for HCl removal would achieve a 95 percent reduction in SO_2; by reducing the removal efficiency for SO_2 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:

$$\text{Annual Emission Rate (tpy)} = ER_{HI} * 0.0005 * Op_{hours} \qquad \textbf{(Equation 4)}$$

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:

$$\text{Annual Emission Rate (tpy)} = ER_C * 0.000001 * Q_S * 60 * Op_{hours} * MW * 0.0026 * 0.0005 * (20.946 - O_2) / (20.946 - \text{Std } O_2) \qquad \textbf{(Equation 5)}$$

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) = $ER_C * 0.0283 * Q_S * 60 * Op_{hours} * 0.000000001 * 0.0022 * 0.0005 * (20.946 - O_2) / (20.946 - \text{Std } O_2)$ **(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)	JJJJJJ	14.5	#2 Fuel Oil	N/A	Existing	Yes	No	No	No	No			$ -	
Manatee Terminal	Process Heater (B)	Minor (Area)	JJJJJJ	12.5	Natural Gas	#2 Fuel Oil	New	Yes	No	No	No	No			$ -	
Martin Terminal	Auxilliary Boiler (A)	Minor (Area)	JJJJJJ	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)	JJJJJJ	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.

Docket No. 110007-EI
FPL IBMACT Cost Matrix
Exhibit RRL-10, Page 1 of 1

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI **EXHIBIT** 15
PARTY FLORIDA POWER & LIGHT CO. (DIRECT)
DESCRIPTION R. R. LABAUVE (RRL-10)
DATE 11/01/11

Docket No. 110007-EI
Progress Energy Florida
Witness: Will Garrett
Exhibit No.___(WG-1)

PROGRESS ENERGY FLORIDA, INC.
ENVIRONMENTAL COST RECOVERY
COMMISSION FORMS 42-1A THROUGH 42-9A

JANUARY 2010 - DECEMBER 2010
FINAL TRUE-UP
DOCKET NO. 110007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI EXHIBIT 16
PARTY PROGRESS ENERGY FLORIDA
DESCRIPTION WILL GARRETT (WG-1)
DATE 11/01/11

Form 42-1A

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2010 through December 2010
(in Dollars)

Line		Period Amount
1	Over/(Under) Recovery for the Period January 2010 through December 2010 (Form 42-2A, Line 5 + 6 + 10)	$ 40,552,348
2	Estimated/Actual True-Up Amount approved for the period January 2010 through December 2010 (Order No. PSC-10-0683-FOF-EI)	34,319,509
3	Final True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2011 to December 2011 (Lines 1 - 2)	**$ 6,232,839**

Docket No. 110007-EI
Progress Energy Florida
Witness: Will Garrett
Exhibit No. __ (WG-1)

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2010 through December 2010

End-of-Period True-Up Amount
(in Dollars)

Line	Description		Actual January 10	Actual February 10	Actual March 10	Actual April 10	Actual May 10	Actual June 10	Actual July 10	Actual August 10	Actual September 10	Actual October 10	Actual November 10	Actual December 10	End of Period Total
1	ECRC Revenues (net of Revenue Taxes)		$19,232,399	$16,984,693	$17,380,801	$15,131,069	$17,200,936	$21,178,756	22,008,123	$22,508,014	$21,562,864	$18,477,809	$17,331,583	$16,646,655	$225,643,702
2	True-Up Provision	$19,745,325	$1,645,444	1,645,444	1,645,444	1,645,444	1,645,444	1,645,444	1,645,444	1,645,444	1,645,444	1,645,444	1,645,444	1,645,444	19,745,325
3	ECRC Revenues Applicable to Period (Lines 1 + 2)		$20,877,843	18,630,137	19,026,245	16,776,513	18,846,379	22,824,200	23,653,567	24,153,458	23,208,308	20,123,253	18,977,026	18,292,099	245,389,027
4	Jurisdictional ECRC Costs														
	a. O & M Activities (Form 42-5A, Line 9)		$3,888,697	3,561,114	3,137,821	3,011,979	4,156,368	5,227,299	5,008,956	5,322,341	4,504,516	3,557,145	3,705,924	4,486,110	49,568,270
	b. Capital Investment Projects (Form 42-7A, Line 9)		$11,030,547	$11,108,069	$11,303,084	$11,426,507	$12,825,473	$14,010,493	14,010,369	$14,003,155	$13,985,909	$13,948,692	$13,931,133	$13,928,529	155,511,960
	c. Other														$0
	c. Total Jurisdictional ECRC Costs		$14,919,244	14,669,183	14,440,905	14,438,486	16,981,841	19,237,792	19,019,325	19,325,496	18,490,425	17,505,837	17,637,057	18,414,639	205,080,230
5	Over/(Under) Recovery (Line 3 - Line 4c)		$5,958,599	3,960,954	4,585,340	2,338,027	1,864,538	3,586,408	4,634,241	4,827,961	4,717,883	2,617,416	1,339,969	(122,540)	40,308,797
6	Interest Provision (Form 42-3A, Line 10)		$4,523	5,088	5,861	6,189	8,363	10,420	9,986	9,546	9,821	9,801	9,873	9,658	99,129
7	Beginning Balance True-Up & Interest Provision		$19,745,325	24,207,425	26,528,023	29,473,781	30,172,553	30,400,011	32,351,395	35,350,178	38,542,242	41,624,502	42,606,275	42,310,674	19,745,325
	a. Deferred True-Up from January 2009 to December 2009 (Order No. PSC-09-0759-FOF-EI)		$4,562,177	4,562,177	4,562,177	4,562,177	4,562,177	4,562,177	4,562,177	4,562,177	4,562,177	4,562,177	4,562,177	4,562,177	4,562,177
8	True-Up Collected/(Refunded) (see Line 2)		($1,645,444)	(1,645,444)	(1,645,444)	(1,645,444)	(1,645,444)	(1,645,444)	(1,645,444)	(1,645,444)	(1,645,444)	(1,645,444)	(1,645,444)	(1,645,444)	(19,745,325)
9	End of Period Total True-Up (Lines 5+6+7+7a+8)		$28,625,180	31,090,200	34,035,958	34,734,730	34,962,188	36,913,572	39,912,355	43,104,419	46,186,679	47,168,452	46,872,851	45,114,525	44,970,103
10	Adjustments to Period Total True-Up Including Interest (a)		$144,422	0	0	0	0	0	0	0	0	0	0	0	144,422
11	End of Period Total True-Up (Lines 9 + 10)		$28,769,602	$31,090,200	$34,035,958	$34,734,730	$34,962,188	$36,913,572	39,912,355	$43,104,419	$46,186,679	$47,168,452	$46,872,851	$45,114,525	$45,114,525
	Change in Deferred Balance		**($4,462,100)**	**(2,320,598)**	**(2,945,758)**	**(698,773)**	**(227,459)**	**(1,951,384)**	**(2,998,784)**	**(3,192,064)**	**(3,082,260)**	**(981,773)**	**295,601**	**1,758,325**	**0**

Form 42-3A

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2010 through December 2010

Interest Provision
(in Dollars)

Line	Description	Actual January 10	Actual February 10	Actual March 10	Actual April 10	Actual May 10	Actual June 10	Actual July 10	Actual August 10	Actual September 10	Actual October 10	Actual November 10	Actual December 10	End of Period Total
1	Beginning True-Up Amount (Form 42-2A, Line 7 + 7a + 10)	$24,451,924	$28,769,602	$31,090,200	$34,035,958	$34,734,730	$34,962,188	$36,913,572	$39,912,355	$43,104,419	$46,186,679	$47,168,452	$46,872,851	
2	Ending True-Up Amount Before Interest (Line 1 + Form 42-2A, Lines 5 + 8)	28,765,079	31,085,112	34,030,097	34,728,541	34,953,825	36,903,152	39,902,369	43,094,873	46,176,858	47,158,651	46,862,978	45,104,867	
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	53,217,003	59,854,715	65,120,297	68,764,499	69,688,555	71,865,339	76,815,941	83,007,228	89,281,277	93,345,331	94,031,430	91,977,718	
4	Average True-Up Amount (Line 3 x 1/2)	26,608,502	29,927,358	32,560,149	34,382,250	34,844,278	35,932,670	38,407,971	41,503,614	44,640,639	46,672,666	47,015,715	45,988,859	
5	Interest Rate (First Day of Reporting Business Month)	0.20%	0.20%	0.21%	0.21%	0.23%	0.34%	0.35%	0.28%	0.28%	0.25%	0.25%	0.25%	
6	Interest Rate (First Day of Subsequent Business Month)	0.20%	0.21%	0.21%	0.23%	0.34%	0.35%	0.28%	0.28%	0.25%	0.25%	0.25%	0.25%	
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	0.40%	0.41%	0.42%	0.44%	0.57%	0.69%	0.63%	0.56%	0.53%	0.50%	0.50%	0.50%	
8	Average Interest Rate (Line 7 x 1/2)	0.200%	0.205%	0.210%	0.220%	0.285%	0.345%	0.315%	0.280%	0.265%	0.250%	0.250%	0.250%	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.017%	0.017%	0.018%	0.018%	0.024%	0.029%	0.026%	0.023%	0.022%	0.021%	0.021%	0.021%	
10	Interest Provision for the Month (Line 4 x Line 9)	$4,523	$5,088	$5,861	$6,189	$8,363	$10,420	$9,986	$9,546	$9,821	$9,801	$9,873	$9,658	$99,129

Docket No. 110007-EI
Progress Energy Florida
Witness: Will Garrett
Exhibit No.__(WG-1)
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Form 42 4A

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2010 through December 2010

Variance Report of O&M Activities
(In Dollars)

Line			(1) Actual	(2) Estimated/ Actual	(3) Variance Amount	(4) Variance Percent
1	Description of O&M Activities					
	1	Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$5,402,343	$4,777,420	$624,923	13%
	1a	Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	4,344,188	4,769,456	(425,268)	-9%
	2	Distribution System Environmental Investigation, Remediation, and Pollution Prevention	8,743,219	8,591,484	151,735	2%
	3	Pipeline Integrity Management	840,767	1,109,871	(269,104)	-24%
	4	Above Ground Tank Secondary Containment	0	0	0	0%
	5	SO2 Emissions Allowances	12,224,739	11,586,850	637,889	6%
	6	Phase II Cooling Water Intake	0	0	0	0%
	6.a	Phase II Cooling Water Intake 316(b) - Intm	0	0	0	0%
	7.2	CAIR - Peaking - Demand	46,899	67,300	(20,401)	-30%
	7.4	CAIR Crystal River - Base	9,945,902	11,596,397	(1,650,495)	-14%
	7.4	CAIR Crystal River - Energy	8,306,687	10,001,596	(1,694,909)	-17%
	7.4	CAIR Crystal River - A&G	79,641	16,871	62,770	372%
	8	Arsenic Groundwater Standard - Base	19,256	20,000	(744)	-4%
	9	Sea Turtle - Coastal Street Lighting - Distrib	559	504	55	11%
	11	Modular Cooling Towers - Base	3,336,752	3,336,752	0	0%
	12	Greenhouse Gas Inventory and Reporting - Energy	6,642	11,250	(4,608)	-41%
	13	Mercury Total Daily Maximum Loads Monitoring - Energy	36,077	36,077	0	0%
	14	Hazardous Air Pollutants (HAPs) ICR Program - Energy	416,877	400,000	16,877	4%
	15	Effluent Limitation Guidelines ICR Program - Energy	21,176	60,000	(38,824)	-65%
2	Total O&M Activities - Recoverable Costs		**$53,771,723**	**$56,381,828**	**($2,610,105)**	-5%
3	Recoverable Costs Allocated to Energy		21,012,198	22,095,773	(1,083,575)	-5%
4	Recoverable Costs Allocated to Demand		32,759,525	34,286,055	(1,526,530)	-4%

Notes:

Column (1) is the End of Period Totals on Form 42-5A
Column (2) = Estimated actual
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Form 42-5A

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2010 through December 2010

O&M Activities
(in Dollars)

Line	Description	Actual January 10	Actual February 10	Actual March 10	Actual April 10	Actual May 10	Actual June 10	Actual July 10	Actual August 10	Actual September 10	Actual October 10	Actual November 10	Actual December 10	End of Period Total
1	Description of O&M Activities													
	1 Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$158,430	$592,079	$285,934	$591,614	$247,256	$447,819	$762,686	$316,744	$355,489	$436,570	$651,370	$556,352	$5,402,343
	1a Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	335,766	440,280	682,522	163,291	684,620	341,004	148,019	241,072	276,277	160,400	432,979	437,955	4,344,188
	2 Distribution System Environmental Investigation, Remediation, and Pollution Prevention	336,598	342,770	689,776	615,415	874,009	982,915	976,028	1,076,034	808,595	787,990	541,932	711,155	8,743,219
	3 Pipeline Integrity Management, Review/Update Plan and Risk Assessments - Intm	70,466	11,175	32,306	17,183	17,025	15,558	59,422	66,186	38,166	127,256	78,590	307,433	840,767
	4 Above Ground Tank Secondary Containment - Pkg	0	0	0	0	0	0	0	0	0	0	0	0	0
	5 SO2/NOx Emissions Allowances	2,507,716	959,635	625,768	531,288	1,100,907	1,339,123	1,075,588	946,839	886,096	668,736	580,852	1,002,192	12,224,739
	6 Phase II Cooling Water Intake 316(b) - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
	6a Phase II Cooling Water Intake 316(b) - Intm	0	0	0	0	0	0	0	0	0	0	0	0	0
	7.2 CAIR - Peaking	0	29,669	17,230	0	0	0	0	0	0	7,513	(7,513)	0	46,899
	7.4 CAIR Crystal River - Base	445,711	647,426	651,697	669,730	722,204	762,312	591,954	1,410,512	1,030,071	923,209	1,026,623	1,064,453	9,945,902
	7.4 CAIR Crystal River - Energy	217,735	868,271	176,477	710,931	653,033	863,482	989,414	835,013	630,306	769,749	744,743	847,532	8,306,687
	7.4 CAIR Crystal River - A&G	661	1,117	2,859	1,757	1,484	0	2,841	13,541	13,662	21,783	12,321	7,615	79,641
	8 Arsenic Groundwater Standard - Base	0	0	7,468	0	0	0	0	0	7,276	0	1,198	3,314	19,256
	9 Sea Turtle - Coastal Street Lighting - Distrib	0	0	104	0	0	0	0	0	0	0	0	455	559
	11 Modular Cooling Towers - Base	0	0	0	0	0	834,188	834,188	834,188	834,188	0	0	0	3,336,752
	12 Greenhouse Gas Inventory and Reporting - Energy	0	0	0	0	0	0	0	0	0	1,312	2,952	2,378	6,642
	13 Mercury Total Daily Maximum Loads Monitoring - Energy	9,019	0	0	9,019	0	0	9,019	0	0	9,019	0	0	36,077
	14 Hazardous Air Pollutants (HAPs) ICR Program - Energy	0	26,510	187,956	24,573	83,727	33,238	63,567	(694)	0	(2,000)	0	0	416,877
	15 Effluent Limitation Guidelines ICR Program - Energy	0	0	0	0	0	0	0	0	575	0	20,601	0	21,176
2	Total of O&M Activities	4,082,103	3,918,932	3,360,097	3,334,803	4,384,265	5,619,639	5,512,726	5,739,435	4,880,702	3,911,538	4,086,649	4,940,835	$53,771,723
3	Recoverable Costs Allocated to Energy	2,734,470	1,854,416	990,202	1,275,812	1,837,667	2,235,843	2,137,588	1,781,158	1,516,977	1,446,817	1,349,148	1,852,102	21,012,198
4	Recoverable Costs Allocated to Demand - Transm	158,430	592,079	285,934	591,614	247,256	447,819	762,686	316,744	355,489	436,570	651,370	556,352	5,402,343
	Recoverable Costs Allocated to Demand - Distrib	672,365	783,051	1,372,402	778,707	1,558,629	1,323,919	1,124,047	1,317,107	1,084,872	948,390	974,912	1,149,565	13,087,965
	Recoverable Costs Allocated to Demand - Prod-Base	445,711	647,426	659,165	669,730	722,204	1,596,500	1,426,142	2,244,700	1,871,535	923,209	1,027,821	1,067,768	13,301,910
	Recoverable Costs Allocated to Demand - Prod-Intm	70,466	11,175	32,306	17,183	17,025	15,558	59,422	66,186	38,166	127,256	78,590	307,433	840,767
	Recoverable Costs Allocated to Demand - Prod-Peaking	0	29,669	17,230	0	0	0	0	0	0	7,513	(7,513)	0	46,899
	Recoverable Costs Allocated to Demand - A&G	661	1,117	2,859	1,757	1,484	0	2,841	13,541	13,662	21,783	12,321	7,615	79,641
5	Retail Energy Jurisdictional Factor	0.97380	0.94550	0.94740	0.94960	0.96100	0.95710	0.95110	0.95380	0.95080	0.94900	0.96690	0.97260	
6	Retail Transmission Demand Jurisdictional Factor	0.68113	0.68113	0.68113	0.68113	0.68113	0.68113	0.68113	0.68113	0.68113	0.68113	0.68113	0.68113	
	Retail Distribution Demand Jurisdictional Factor	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	
	Retail Production Demand Jurisdictional Factor - Base	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	
	Retail Production Demand Jurisdictional Factor - Intm	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	
	Retail Production Demand Jurisdictional Factor - Peaking	0.91248	0.91248	0.91248	0.91248	0.91248	0.91248	0.91248	0.91248	0.91248	0.91248	0.91248	0.91248	
	Retail Production Demand Jurisdictional Factor - A&G	0.87691	0.87691	0.87691	0.87691	0.87691	0.87691	0.87691	0.87691	0.87691	0.87691	0.87691	0.87691	
7	Jurisdictional Energy Recoverable Costs (A)	2,662,827	1,753,351	938,117	1,211,511	1,765,998	2,139,925	2,033,060	1,698,868	1,442,342	1,373,029	1,304,491	1,801,354	20,124,873
8	Jurisdictional Demand Recoverable Costs - Transm (B)	107,911	403,283	194,758	402,966	168,413	305,023	519,488	215,744	242,134	297,361	443,668	378,948	3,679,697
	Jurisdictional Demand Recoverable Costs - Distrib (B)	669,837	780,106	1,367,242	775,779	1,552,769	1,318,941	1,119,821	1,312,154	1,080,793	944,824	971,246	1,145,242	13,038,754
	Jurisdictional Demand Recoverable Costs - Prod-Base (B)	405,994	589,734	600,427	610,050	657,848	1,454,236	1,299,059	2,044,675	1,704,763	840,941	936,232	972,619	12,116,578
	Jurisdictional Demand Recoverable Costs - Prod-Intm (B)	41,548	6,589	19,048	10,132	10,038	9,174	35,036	39,025	22,504	75,033	46,338	181,269	495,734
	Jurisdictional Demand Recoverable Costs - Prod-Peaking (B)	0	27,072	15,722	0	0	0	0	0	0	6,855	(6,855)	0	42,794
	Jurisdictional Demand Recoverable Costs - A&G	580	979	2,507	1,541	1,302	0	2,492	11,875	11,980	19,102	10,804	6,678	69,840
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$3,888,697	$3,561,114	$3,137,821	$3,011,979	$4,156,368	$5,227,299	$5,008,956	$5,322,341	$4,504,516	$3,557,145	$3,705,924	$4,486,110	$49,568,270

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

Form 42 6A

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2010 through December 2010

Variance Report of Capital Investment Activities
(In Dollars)

Line			(1) YTD Actual	(2) Estimated/ Actual	(3) Variance Amount	(4) Variance Percent
1	Description of Capital Investment Activities					
	3.x	Pipeline Integrity Management - Bartow/Anclote Pipeline-Interme	$450,470	$450,470	$0	0%
	4.x	Above Ground Tank Secondary Containment	1,914,209	1,913,652	557	0%
	5	SO2 Emissions Allowances	3,867,122	3,863,015	4,107	0%
	7.x	CAIR	164,231,267	164,674,590	(443,323)	0%
	9	Sea Turtle - Coastal Street Lighting -Distribution	1,434	1,511	(77)	-5%
	10.x	Underground Storage Tanks-Base	32,753	32,751	2	0%
	11	Modular Cooling Towers - Base	155,744	155,745	(1)	0%
	11.1	Thermal Discharge Permanent Cooling Tower - Base - Demand	49,204	49,204	0	0%
2	Total Capital Investment Activities - Recoverable Costs		**170,702,202**	**171,140,938**	**($438,736)**	0%
3	Recoverable Costs Allocated to Energy		3,914,836	3,911,246	$3,590	0%
4	Recoverable Costs Allocated to Demand		$166,787,367	$167,229,692	($442,325)	0%

Notes:
Column (1) is the End of Period Totals on Form 42-7A
Column (2) = Estimated actual
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Form 42-7A

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2010 through December 2010

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line	Description	Actual January 10	Actual February 10	Actual March 10	Actual April 10	Actual May 10	Actual June 10	Actual July 10	Actual August 10	Actual September 10	Actual October 10	Actual November 10	Actual December 10	End of Period Total
1	Description of Investment Projects (A)													
3.1	Pipeline Integrity Management - Bartow/Anclote Pipeline-Intermediate	$37,928	$37,858	$37,787	$37,716	$37,645	$37,573	37,504	$37,434	$37,363	$37,292	$37,221	$37,149	$450,470
4.1	Above Ground Tank Secondary Containment - Peaking	116,415	118,201	122,534	124,996	124,743	124,502	124,243	123,983	123,686	123,406	123,128	122,849	1,472,666
4.2	Above Ground Tank Secondary Containment - Base	33,914	33,859	33,805	33,751	33,695	33,641	33,587	33,533	33,477	33,423	33,582	33,657	403,924
4.3	Above Ground Tank Secondary Containment - Intermediate	3,162	3,157	3,152	3,147	3,142	3,137	3,132	3,128	3,122	3,118	3,113	3,109	37,619
5	SO2/NOX Emissions Allowances - Energy	371,951	356,757	348,455	342,850	335,102	325,709	316,404	307,156	298,773	291,696	286,016	286,253	3,867,122
7.1	CAIR/CAMR Anclote- Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0
7.2	CAIR CT's - Peaking	21,801	21,768	21,734	21,702	21,670	21,637	21,605	21,573	21,540	21,507	21,476	21,446	259,457
7.3	CAMR Crystal River - Base	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	31,728
7.4	CAIR Crystal River AFUDC - Base	11,485,738	11,596,799	11,814,644	11,952,421	13,493,121	14,806,309	14,818,480	14,819,338	14,809,761	14,778,662	14,761,155	14,755,940	163,892,368
7.4	CAIR Crystal River AFUDC - Energy	4,127	4,088	4,123	4,591	4,071	3,660	3,741	4,199	5,107	3,898	2,731	3,375	47,714
9	Sea Turtle - Coastal Street Lighting -Distribution	120	120	120	120	120	120	119	119	119	119	119	119	1,434
10.1	Underground Storage Tanks-Base	1,864	1,861	1,858	1,856	1,853	1,850	1,847	1,845	1,842	1,839	1,836	1,834	22,185
10.2	Underground Storage Tanks-Intermediate	891	889	887	886	883	882	879	878	876	874	872	871	10,568
11	Modular Cooling Towers - Base	13,536	13,435	13,333	13,232	13,131	13,030	12,928	12,827	12,725	12,624	12,522	12,421	155,744
11.1	Crystal River Thermal Discharge Compliance Project - Base	4,126	4,121	4,117	4,112	4,107	4,103	4,098	4,094	4,088	4,084	4,079	4,075	49,204
2	Total Investment Projects - Recoverable Costs	12,098,217	12,195,555	12,409,192	12,544,024	14,075,927	15,378,797	15,381,211	15,372,731	15,355,123	15,315,186	15,290,494	15,285,742	170,702,202
3	Recoverable Costs Allocated to Energy	376,078	360,845	352,578	347,441	339,173	329,369	320,145	311,355	303,880	295,594	288,747	289,628	3,914,836
	Recoverable Costs Allocated to Demand	120	120	120	120	120	120	119	119	119	119	119	119	1,434
4	Recoverable Costs Allocated to Demand - Production - Base	11,541,822	11,652,719	11,870,401	12,008,016	13,548,551	14,861,577	14,873,584	14,874,281	14,864,537	14,833,276	14,815,818	14,810,571	164,555,153
	Recoverable Costs Allocated to Demand - Production - Intermediate	41,981	41,904	41,826	41,749	41,670	41,592	41,515	41,440	41,361	41,284	41,206	41,129	498,657
	Recoverable Costs Allocated to Demand - Production - Peaking	138,216	139,967	144,268	146,698	146,413	146,139	145,848	145,536	145,226	144,913	144,604	144,295	1,732,123
5	Retail Energy Jurisdictional Factor	0.97380	0.94550	0.94740	0.94960	0.96100	0.95710	0.9511	0.95380	0.95080	0.94900	0.96690	0.97260	
	Retail Distribution Demand Jurisdictional Factor	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.9962	0.99624	0.99624	0.99624	0.99624	0.99624	
6	Retail Demand Jurisdictional Factor - Production - Base	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.9109	0.91089	0.91089	0.91089	0.91089	0.91089	
	Retail Demand Jurisdictional Factor - Production - Intermediate	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.5896	0.58962	0.58962	0.58962	0.58962	0.58962	
	Retail Demand Jurisdictional Factor - Production - Peaking	0.91248	0.91248	0.91248	0.91248	0.91248	0.91248	0.9125	0.91248	0.91248	0.91248	0.91248	0.91248	
7	Jurisdictional Energy Recoverable Costs (B)	366,225	341,179	334,032	329,930	325,945	315,239	304,490	296,970	288,929	280,519	279,190	281,692	3,744,343
	Jurisdictional Demand Recoverable Costs (B)	120	120	120	120	120	120	119	119	119	119	119	119	1,429
8	Jurisdictional Demand Recoverable Costs - Production - Base (C)	10,513,330	10,614,345	10,812,630	10,937,982	12,341,240	13,537,262	13,548,199	13,548,834	13,539,958	13,511,483	13,495,580	13,490,801	149,891,643
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	24,753	24,707	24,661	24,616	24,569	24,523	24,478	24,434	24,387	24,342	24,296	24,250	294,018
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	126,119	127,717	131,641	133,859	133,599	133,349	133,083	132,799	132,516	132,230	131,948	131,666	1,580,527
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$11,030,547	$11,108,069	$11,303,084	$11,426,507	$12,825,473	$14,010,493	14,010,369	$14,003,155	$13,985,909	$13,948,692	$13,931,133	$13,928,529	$155,511,960

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8A, Line 9; Form 42-8A, Line 5 for Projects 5 - Allowances and Project 7. 4 - Reagents
(B) Line 3 x Line 5
(C) Line 4 x Line 6

Form 42-8A
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2010 through December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: PIPELINE INTEGRITY MANAGEMENT - Bartow/Anclote Pipeline (Project 3.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 10	Actual February 10	Actual March 10	Actual April 10	Actual May 10	Actual June 10	Actual July 10	Actual August 10	Actual September 10	Actual October 10	Actual November 10	Actual December 10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	
3	Less: Accumulated Depreciation		(565,408)	(573,144)	(580,880)	(588,616)	(596,352)	(604,088)	(611,824)	(619,560)	(627,296)	(635,032)	(642,768)	(650,504)	(658,240)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		3,014,328	3,006,592	2,998,856	2,991,120	2,983,384	2,975,648	2,967,912	2,960,176	2,952,440	2,944,704	2,936,968	2,929,232	2,921,496	
6	Average Net Investment			3,010,460	3,002,724	2,994,988	2,987,252	2,979,516	2,971,780	2,964,044	2,956,308	2,948,572	2,940,836	2,933,100	2,925,364	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		7,407	7,388	7,369	7,350	7,330	7,311	7,293	7,274	7,255	7,236	7,217	7,196	87,626
	b. Equity Component Grossed Up For Taxes	8.02%		20,128	20,077	20,025	19,973	19,922	19,869	19,818	19,767	19,715	19,663	19,611	19,560	238,128
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			7,736	7,736	7,736	7,736	7,736	7,736	7,736	7,736	7,736	7,736	7,736	7,736	92,832
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes (D)			2,657	2,657	2,657	2,657	2,657	2,657	2,657	2,657	2,657	2,657	2,657	2,657	31,884
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			37,928	37,858	37,787	37,716	37,645	37,573	37,504	37,434	37,363	37,292	37,221	37,149	450,470
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			37,928	37,858	37,787	37,716	37,645	37,573	37,504	37,434	37,363	37,292	37,221	37,149	450,470
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)			0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			22,363	22,322	22,280	22,238	22,196	22,154	22,113	22,072	22,030	21,988	21,946	21,904	265,606
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$22,363	$22,322	$22,280	$22,238	$22,196	$22,154	$22,113	$22,072	$22,030	$21,988	$21,946	$21,904	$265,606

Notes:
(A) N/A
(B) Line 6 x 10.96% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Depreciation calculated in Pipeline Integrity Management section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Property tax calculated in Pipeline Integrity Management section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2009 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 110007-EI
Progress Energy Florida
Witness: Will Garrett
Exhibit No. __ (WG-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2010 through December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - PEAKING (Project 4.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 10	Actual February 10	Actual March 10	Actual April 10	Actual May 10	Actual June 10	Actual July 10	Actual August 10	Actual September 10	Actual October 10	Actual November 10	Actual December 10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$166,070	$274,127	$187,776	$5,242	$13	$4,598	$19	$0	$0	$0	$0	$147	$637,993
	b. Clearings to Plant			86,013	6,439	1,315,204	5,242	13	4,598	19	0	0	0	0	147	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$8,646,990	8,733,003	8,739,442	10,054,646	10,059,887	10,059,901	10,064,499	10,064,518	10,064,518	10,064,518	10,064,518	10,064,518	10,064,665	
3	Less: Accumulated Depreciation		(485,844)	(513,021)	(540,214)	(568,859)	(599,353)	(629,848)	(660,354)	(690,860)	(721,366)	(751,872)	(782,378)	(812,884)	(843,390)	
4	CWIP - Non-Interest Bearing		779,682	859,740	1,127,428	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		8,940,828	9,079,722	9,326,656	9,485,786	9,460,534	9,430,052	9,404,145	9,373,658	9,343,152	9,312,646	9,282,140	9,251,634	9,221,275	
6	Average Net Investment			9,010,275	9,203,189	9,406,221	9,473,160	9,445,293	9,417,098	9,388,901	9,358,405	9,327,899	9,297,393	9,266,887	9,236,454	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		22,169	22,643	23,143	23,306	23,239	23,169	23,099	23,025	22,950	22,875	22,800	22,724	275,142
	b. Equity Component Grossed Up For Taxes	8.02%		60,244	61,535	62,892	63,339	63,152	62,966	62,777	62,571	62,369	62,164	61,961	61,758	747,728
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			27,177	27,193	28,646	30,494	30,495	30,506	30,506	30,506	30,506	30,506	30,506	30,506	357,547
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes (D)			6,825	6,830	7,853	7,857	7,857	7,861	7,861	7,861	7,861	7,861	7,861	7,861	92,249
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			116,415	118,201	122,534	124,996	124,743	124,502	124,243	123,963	123,686	123,406	123,128	122,849	1,472,666
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			116,415	118,201	122,534	124,996	124,743	124,502	124,243	123,963	123,686	123,406	123,128	122,849	1,472,666
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Peaking)			0.91248	0.91248	0.91248	0.91248	0.91248	0.91248	0.91248	0.91248	0.91248	0.91248	0.91248	0.91248	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			106,226	107,856	111,809	114,056	113,825	113,606	113,369	113,114	112,861	112,606	112,352	112,097	1,343,778
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$106,226	$107,856	$111,809	$114,056	$113,825	$113,606	$113,369	$113,114	$112,861	$112,606	$112,352	$112,097	$1,343,778

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2009 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 110007-EI
Progress Energy Florida
Witness: Will Garrett
Exhibit No. __ (WG-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2010 through December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Base (Project 4.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 10	Actual February 10	Actual March 10	Actual April 10	Actual May 10	Actual June 10	Actual July 10	Actual August 10	Actual September 10	Actual October 10	Actual November 10	Actual December 10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$28,322	$75	$28,397
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	28,322	75	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$2,849,412	2,849,412	2,849,412	2,849,412	2,849,412	2,849,412	2,849,412	2,849,412	2,849,412	2,849,412	2,849,412	2,877,734	2,877,810	
3	Less: Accumulated Depreciation		(71,580)	(77,549)	(83,518)	(89,487)	(95,456)	(101,425)	(107,394)	(113,363)	(119,332)	(125,301)	(131,270)	(137,298)	(143,326)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+ 3 + 4)		$2,777,833	2,771,864	2,765,895	2,759,926	2,753,957	2,747,988	2,742,019	2,736,050	2,730,081	2,724,112	2,718,143	2,740,437	2,734,484	
6	Average Net Investment			2,774,849	2,768,880	2,762,911	2,756,942	2,750,973	2,745,004	2,739,035	2,733,066	2,727,097	2,721,128	2,729,290	2,737,461	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		6,827	6,812	6,798	6,783	6,768	6,754	6,739	6,725	6,709	6,695	6,715	6,736	81,061
	b. Equity Component Grossed Up For Taxes	8.02%		18,563	18,513	18,473	18,434	18,393	18,353	18,314	18,274	18,234	18,194	18,249	18,303	220,287
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			5,969	5,969	5,969	5,969	5,969	5,969	5,969	5,969	5,969	5,969	6,028	6,028	71,746
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)			2,565	2,565	2,565	2,565	2,565	2,565	2,565	2,565	2,565	2,565	2,590	2,590	30,830
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			33,914	33,859	33,805	33,751	33,695	33,641	33,587	33,533	33,477	33,423	33,582	33,657	403,924
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			33,914	33,859	33,805	33,751	33,695	33,641	33,587	33,533	33,477	33,423	33,582	33,657	403,924
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			30,892	30,842	30,793	30,743	30,692	30,643	30,594	30,545	30,494	30,445	30,590	30,658	367,930
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$30,892	$30,842	$30,793	$30,743	$30,692	$30,643	$30,594	$30,545	$30,494	$30,445	$30,590	$30,658	$367,930

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2009 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Progress Energy Florida
Witness: Will Garrett
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2010 through December 2010

Form 42-8A
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Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Intermediate (Project 4.3)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 10	Actual February 10	Actual March 10	Actual April 10	Actual May 10	Actual June 10	Actual July 10	Actual August 10	Actual September 10	Actual October 10	Actual November 10	Actual December 10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	
3	Less: Accumulated Depreciation		(22,218)	(22,750)	(23,282)	(23,814)	(24,346)	(24,878)	(25,410)	(25,942)	(26,474)	(27,006)	(27,538)	(28,070)	(28,602)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+ 3 + 4)		$268,080	267,548	267,016	266,484	265,952	265,420	264,888	264,356	263,824	263,292	262,760	262,228	261,696	
6	Average Net Investment			267,814	267,282	266,750	266,218	265,686	265,154	264,622	264,090	263,558	263,026	262,494	261,962	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		659	658	656	655	654	652	651	650	648	647	646	645	7,821
	b. Equity Component Grossed Up For Taxes	8.02%		1,791	1,787	1,784	1,780	1,776	1,773	1,769	1,766	1,762	1,759	1,755	1,752	21,254
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			532	532	532	532	532	532	532	532	532	532	532	532	6,384
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)			180	180	180	180	180	180	180	180	180	180	180	180	2,160
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			3,162	3,157	3,152	3,147	3,142	3,137	3,132	3,128	3,122	3,118	3,113	3,109	37,619
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			3,162	3,157	3,152	3,147	3,142	3,137	3,132	3,128	3,122	3,118	3,113	3,109	37,619
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)			0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			1,864	1,861	1,858	1,856	1,853	1,850	1,847	1,844	1,841	1,838	1,835	1,833	22,181
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$1,864	$1,861	$1,858	$1,856	$1,853	$1,850	$1,847	$1,844	$1,841	$1,838	$1,835	$1,833	$22,181

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2009 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 110007-EI
Progress Energy Florida
Witness: Will Garrett
Exhibit No. __(WG-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2010 through December 2010

Schedule of Amortization and Return
Deferred Gain on Sales of Emissions Allowances (Project 5)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual January 10	Actual February 10	Actual March 10	Actual April 10	Actual May 10	Actual June 10	Actual July 10	Actual August 10	Actual September 10	Actual October 10	Actual November 10	Actual December 10	End of Period Total
1	Working Capital Dr (Cr)															
	a. 1581001 SO_2 Emission Allowance Inventory		$7,312,132	$7,000,742	$6,834,722	$6,734,332	$6,640,697	$6,519,513	$6,351,199	$6,202,538	$6,061,926	$5,945,567	$5,847,546	$5,776,105	$5,674,079	$5,674,079
	b. 25401FL Auctioned SO_2 Allowance		(1,921,713)	(1,909,321)	(1,896,928)	(1,884,535)	(1,918,979)	(1,901,178)	(1,883,376)	(1,865,575)	(1,847,773)	(1,829,971)	(1,812,170)	(1,794,368)	(1,776,566)	($1,776,566)
	c. 1581002 NOX Emission Allowance Inventory		36,341,932	34,508,214	33,472,206	32,934,435	32,462,755	31,471,529	30,662,919	29,718,191	28,894,162	28,106,625	27,525,607	26,998,394	27,715,427	27,715,427
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0		
2	Total Working Capital		$41,732,351	39,599,635	38,410,000	37,784,232	37,184,472	36,089,865	35,130,742	34,055,154	33,108,315	32,222,220	31,560,983	30,980,131	31,612,939	31,612,939
3	Average Net Investment			40,665,993	39,004,818	38,097,116	37,484,352	36,637,168	35,610,303	34,592,948	33,581,735	32,665,268	31,891,602	31,270,557	31,296,535	
4	Return on Average Net Working Capital Balance (A)															
	a. Debt Component (Line 3 x 2.95% x 1/12)	2.95%		100,051	95,964	93,731	92,223	90,139	87,612	85,109	82,622	80,367	78,463	76,935	76,999	$1,040,215
	b. Equity Component Grossed Up For Taxes	8.02%		271,900	260,793	254,724	250,627	244,963	238,097	231,295	224,534	218,406	213,233	209,081	209,254	2,826,907
5	Total Return Component (B)			371,951	356,757	348,455	342,850	335,102	325,709	316,404	307,156	298,773	291,696	286,016	286,253	3,867,122
6	Expense Dr (Cr)															
	a. 5090001 SO_2 allowance expense			311,390	166,020	100,390	93,636	121,183	168,314	148,661	140,612	116,360	98,020	71,441	102,026	1,638,053
	b. 4074004 Amortization Expense			($12,393)	($12,393)	($12,393)	($34,028)	($17,802)	($17,802)	($17,802)	($17,802)	($17,802)	($17,802)	($17,802)	($17,802)	($213,620)
	c. 5090003 Nox Allowance Expense			$2,208,719	806,008	537,771	471,680	997,525	1,188,611	944,728	824,028	787,538	588,518	527,213	917,967	$10,800,305
	d. Other			$0	0	0	0	0	0							
7	Net Expense (C)			2,507,716	959,635	625,768	531,288	1,100,907	1,339,123	1,075,588	946,839	886,096	668,736	580,852	1,002,192	12,224,739
8	Total System Recoverable Expenses (Lines 5 + 7)			2,879,667	1,316,392	974,223	874,138	1,436,009	1,664,832	1,391,992	1,253,995	1,184,869	960,432	866,868	1,288,445	16,091,861
	a. Recoverable costs allocated to Energy			2,879,667	1,316,392	974,223	874,138	1,436,009	1,664,832	1,391,992	1,253,995	1,184,869	960,432	866,868	1,288,445	16,091,861
	b. Recoverable costs allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor			0.97380	0.94550	0.94740	0.94960	0.96100	0.95710	0.95110	0.95380	0.95080	0.94900	0.96690	0.97260	
10	Demand Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Retail Energy-Related Recoverable Costs (D)			2,804,219	1,244,649	922,979	830,081	1,380,005	1,593,411	1,323,923	1,196,060	1,126,573	911,450	838,175	1,253,141	15,424,667
12	Retail Demand-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Total Jurisdictional Recoverable Costs (Lines 11 • 12)			$ 2,804,219	$ 1,244,649	$ 922,979	$ 830,081	$ 1,380,005	$ 1,593,411	$ 1,323,923	$ 1,196,060	$ 1,126,573	$ 911,450	$ 838,175	$ 1,253,141	$ 15,424,667

Notes:
(A) Line 3 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(B) Line 5 is reported on Capital Schedule
(C) Line 7 is reported on O&M Schedule
(D) Line 8a x Line 9.
(E) Line 8b x Line 10.

Docket No. 110007-EI
Progress Energy Florida
Witness: Will Garrett
Exhibit No. __ (WG-1)

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2010 through December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR - Intermediate (Project 7.1 - Anclote Low Nox Burners and SOFA)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual January 10	Actual February 10	Actual March 10	Actual April 10	Actual May 10	Actual June 10	Actual July 10	Actual August 10	Actual September 10	Actual October 10	Actual November 10	Actual December 10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation		$0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$ -	0	0	0	0	0	0	0	0	0	0	0	0	
6	Average Net Investment			0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Equity Component Grossed Up For Taxes	8.02%		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	1.60%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.007440		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intm)			0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2009 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 110007-EI
Progress Energy Florida
Witness: Will Garrett
Exhibit No. __ (WG-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2010 through December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR - Peaking (Project 7.2 - CT Emission Monitoring Systems)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 10	Actual February 10	Actual March 10	Actual April 10	Actual May 10	Actual June 10	Actual July 10	Actual August 10	Actual September 10	Actual October 10	Actual November 10	Actual December 10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	
3	Less: Accumulated Depreciation		(91,024)	(94,564)	(98,104)	(101,644)	(105,184)	(108,724)	(112,264)	(115,804)	(119,344)	(122,884)	(126,424)	(129,964)	(133,504)	
4	CWIP - Non-Interest Bearing		0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$1,843,377	1,839,836	1,836,296	1,832,756	1,829,216	1,825,676	1,822,136	1,818,596	1,815,056	1,811,516	1,807,976	1,804,436	1,800,896	
6	Average Net Investment			1,841,607	1,838,067	1,834,527	1,830,987	1,827,447	1,823,907	1,820,367	1,816,827	1,813,287	1,809,747	1,806,207	1,802,667	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		4,531	4,521	4,513	4,503	4,495	4,487	4,478	4,469	4,460	4,451	4,443	4,436	53,787
	b. Equity Component Grossed Up For Taxes	8.02%		12,314	12,289	12,265	12,243	12,219	12,194	12,171	12,148	12,124	12,100	12,077	12,054	146,198
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			3,540	3,540	3,540	3,540	3,540	3,540	3,540	3,540	3,540	3,540	3,540	3,540	42,480
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)			1,416	1,416	1,416	1,416	1,416	1,416	1,416	1,416	1,416	1,416	1,416	1,416	16,992
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			21,801	21,766	21,734	21,702	21,670	21,637	21,605	21,573	21,540	21,507	21,476	21,446	259,457
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			21,801	21,766	21,734	21,702	21,670	21,637	21,605	21,573	21,540	21,507	21,476	21,446	259,457
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Peaking)			0.91248	0.91248	0.91248	0.91248	0.91248	0.91248	0.91248	0.91248	0.91248	0.91248	0.91248	0.91248	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			19,893	19,861	19,832	19,803	19,773	19,743	19,714	19,685	19,655	19,625	19,596	19,569	236,749
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$19,893	$19,861	$19,832	$19,803	$19,773	$19,743	$19,714	$19,685	$19,655	$19,625	$19,596	$19,569	$236,749

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Depreciation calculated in CAIR CTs section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(D) Property tax calculated in CAIR CTs section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2009 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 110007-EI
Progress Energy Florida
Witness: Will Garrett
Exhibit No. __(WG-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2010 through December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: CAMR - Crystal River - Base (Project 7.3 - Continuous Mercury Monitoring Systems)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 10	Actual February 10	Actual March 10	Actual April 10	Actual May 10	Actual June 10	Actual July 10	Actual August 10	Actual September 10	Actual October 10	Actual November 10	Actual December 10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing		289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	
5	Net Investment (Lines 2 + 3 + 4)		289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	
6	Average Net Investment			289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		711	711	711	711	711	711	711	711	711	711	711	711	$8,532
	b. Equity Component Grossed Up For Taxes	8.02%		1,933	1,933	1,933	1,933	1,933	1,933	1,933	1,933	1,933	1,933	1,933	1,933	23,196
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C) 2.10%			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.010800			0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	31,728
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	31,728
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			2,408	2,408	2,408	2,408	2,408	2,408	2,408	2,408	2,408	2,408	2,408	2,408	28,901
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$2,408	$2,408	$2,408	$2,408	$2,408	$2,408	$2,408	$2,408	$2,408	$2,408	$2,408	$2,408	$28,901

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2009 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2010 through December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR - Base - AFUDC (Project 7.4 - Crystal River FGD and SCR)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 10	Actual February 10	Actual March 10	Actual April 10	Actual May 10	Actual June 10	Actual July 10	Actual August 10	Actual September 10	Actual October 10	Actual November 10	Actual December 10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 13,476,842	$ 9,743,699	$ 14,168,367	$ 9,796,370	$ 982,886	$ 1,936,778	1,261,192	1,917,385	726,410	(1,463,843)	1,779,301	1,445,686	$86,771,892
	b. Clearings to Plant			(24,414)	21,313,554	16,544,236	10,844,279	231,736,087	4,737,481	2,145,936	1,917,385	726,410	(1,632,948)	1,474,396	1,142,673	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			1,340,959	1,322,595	1,284,359	1,312,048	1,148,920	0	0	0	0	0	0	0	6,408,881
2	Plant-in-Service/Depreciation Base		$961,822,260	951,897,865	973,211,410	989,755,647	1,000,399,927	1,232,136,994	1,236,873,474	1,239,019,410	1,240,936,795	1,241,663,208	1,240,030,258	1,241,504,654	1,242,647,327	
3	Less: Accumulated Depreciation		(4,253,150)	(6,223,459)	(8,206,361)	(10,237,440)	(12,291,058)	(14,588,243)	(17,135,055)	(19,683,929)	(22,236,687)	(24,790,475)	(27,341,353)	(29,895,297)	(32,451,621)	
4	CWIP - AFUDC-Interest Bearing NOTE 1		220,322,107	244,164,322	233,917,062	232,825,570	233,289,709	3,685,447	884,744	(0)	(0)	(0)	169,105	474,009	777,023	
5	Net Investment (Lines 2 + 3 + 4)		$ 1,178,891,220	1,189,838,718	1,198,922,111	1,212,343,778	1,221,398,577	1,221,233,198	1,220,623,164	1,219,335,481	1,218,700,108	1,216,872,730	1,212,858,009	1,212,083,366	1,210,972,728	
6	Average Net Investment (B)			946,671,754	955,339,722	972,261,628	983,813,539	1,102,829,309	1,218,643,085	1,219,536,952	1,219,017,796	1,217,786,421	1,214,865,370	1,212,470,688	1,211,528,049	
7	Return on Average Net Investment (C)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		2,329,108	2,350,434	2,392,068	2,420,486	2,713,302	2,998,244	3,000,444	2,999,165	2,996,136	2,988,947	2,983,056	2,980,738	33,152,130
	b. Equity Component Grossed Up For Taxes	8.02%		6,329,619	6,387,573	6,500,718	6,577,955	7,373,711	8,148,068	8,154,044	8,150,573	8,142,341	8,122,810	8,106,799	8,100,498	90,094,707
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (D)			1,970,303	1,982,902	2,031,079	2,053,619	2,297,185	2,546,812	2,548,875	2,552,758	2,553,788	2,550,878	2,553,944	2,556,324	28,198,465
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (E)			858,706	875,890	890,779	900,359	1,108,923	1,113,185	1,115,117	1,116,842	1,117,496	1,116,027	1,117,356	1,118,382	12,447,064
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
																0
9	Total System Recoverable Expenses (Lines 7 + 8)			11,485,736	11,596,799	11,814,644	11,952,421	13,493,121	14,806,309	14,818,480	14,819,336	14,809,761	14,778,662	14,761,155	14,755,940	163,892,368
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			11,485,736	11,596,799	11,814,644	11,952,421	13,493,121	14,806,309	14,818,480	14,819,336	14,809,761	14,778,662	14,761,155	14,755,940	163,892,368
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	
12	Retail Energy-Related Recoverable Costs (F)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (G)			10,462,244	10,563,408	10,761,841	10,887,341	12,290,749	13,486,919	13,498,005	13,498,787	13,490,063	13,461,735	13,445,788	13,441,038	149,287,919
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$10,462,244	$10,563,408	$10,761,841	$10,887,341	$12,290,749	$13,486,919	13,498,005	$13,498,787	$13,490,063	$13,461,735	$13,445,788	$13,441,038	$149,287,919

Notes:
NOTE 1 Prior to Oct 2010, AFUDC was calculated on all CAIR projects. As of Oct 2010, AFUDC is determined on a project by project basis. Consequently, the Net Investment Line 5 calculation excludes CWIP for Jan - Sep 2010 as it was AFUDC interest bearing.
The Net Investment Line 5 calculation for Oct - Dec 2010 includes CWIP as it is non-AFUDC interest bearing. AFUDC is not being earned on CAIR projects comprising this total.

(A) AFUDC rate reflected within Docket 100134-EI per Order PSC-10-0258-PCO-EI.
(B) Line represents the Average Net Investment excluding AFUDC interest-bearing CWIP projects -- see NOTE 1. Refer to Capital Program Detail for Average Net Investment Return on which Line 7 is calculated.
(C) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(D) Depreciation calculated only on assets placed in-service which appear in CAIR Crystal River section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(E) Property taxes calculated only on assets placed in-service which appear in CAIR Crystal River section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2009 Effective Tax Rate on original cost.
(F) Line 9a x Line 10
(G) Line 9b x Line 11

Docket No. 110007-EI
Progress Energy Florida
Witness: Will Garrett
Exhibit No. __ (WG-1)

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2010 through December 2010

Schedule of Amortization and Return
For Project: CAIR - Base - AFUDC (Project 7.4 - Reagents and By-products)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 10	Actual February 10	Actual March 10	Actual April 10	Actual May 10	Actual June 10	Actual July 10	Actual August 10	Actual September 10	Actual October 10	Actual November 10	Actual December 10	End of Period Total
1	Working Capital Dr (Cr)															
	a. 1544001 Ammonia Inventory		$10,615	$28,781	$20,562	$42,013	$55,176	$38,165	$35,719	$33,796	$32,447	$69,365	$21,601	$37,827	$50,759	$50,759
	b. 1544004 Limestone Inventory		411,061	452,062	392,584	446,311	460,486	336,405	390,116	358,486	493,437	521,409	240,012	297,812	351,659	351,659
2	Total Working Capital		$421,677	480,843	413,146	488,324	515,662	374,569	425,835	392,282	525,884	590,773	261,613	335,639	402,418	402,418
3	Average Net Investment			451,260	446,995	450,735	501,993	445,116	400,202	409,058	459,083	558,329	426,193	298,626	369,028	
4	Return on Average Net Working Capital Balance (A)															
	a. Debt Component (Line 3 x 2.95% x 1/12)	2.95%		1,110	1,100	1,109	1,235	1,095	985	1,006	1,129	1,374	1,049	735	908	$12,835
	b. Equity Component Grossed Up For Taxes	8.02%		3,017	2,989	3,014	3,356	2,976	2,676	2,735	3,070	3,733	2,850	1,997	2,467	34,879
5	Total Return Component (B)			4,127	4,088	4,123	4,591	4,071	3,660	3,741	4,199	5,107	3,898	2,731	3,375	47,714
6	Expense Dr (Cr)															
	a. 5020011 Ammonia expense			173,336	194,597	176,497	184,931	135,197	278,065	419,808	372,265	230,040	319,498	317,737	345,558	3,147,528
	b. 5020012 Limestone Expense			44,400	63,252	102,970	133,485	124,454	203,198	277,203	289,575	202,726	325,861	279,666	373,318	2,420,108
	c. 5020013 Dibasic Acid Expense			0	0	3,514	0	0	0	0	0	0	0	6,510	0	10,024
	d. 5020003 Gypsum Disposal/Sale			0	610,423	(106,504)	392,515	393,382	382,219	292,403	173,173	197,541	124,390	140,829	128,656	2,729,026
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
7	Net Expense (C)			217,735	868,271	176,477	710,931	653,033	863,482	989,414	835,013	630,306	769,749	744,743	847,532	8,306,687
8	Total System Recoverable Expenses (Lines 5 + 7)			221,863	872,360	180,600	715,523	657,104	867,142	993,155	839,212	635,413	773,647	747,474	850,907	8,354,401
	a. Recoverable costs allocated to Energy			221,863	872,360	180,600	715,523	657,104	867,142	993,156	839,212	635,413	773,647	747,474	850,907	8,354,401
	b. Recoverable costs allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor			0.97380	0.94550	0.94740	0.94960	0.96100	0.95710	0.95110	0.95380	0.95080	0.94900	0.96690	0.97260	
10	Demand Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Retail Energy-Related Recoverable Costs (D)			216,050	824,816	171,100	679,460	631,477	829,942	944,590	800,440	604,151	734,191	722,733	827,593	7,986,544
12	Retail Demand-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Total Jurisdictional Recoverable Costs (Lines 11 + 12)			$ 216,050	$ 824,816	$ 171,100	$ 679,460	$ 631,477	$ 829,942	$ 944,590	$ 800,440	$ 604,151	$ 734,191	$ 722,733	$ 827,593	$ 7,986,544

Notes:
(A) Line 3 x 10.98% x 1/12. Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(B) Line 5 is reported on Capital Schedule
(C) Line 7 is reported on O&M Schedule
(D) Line 8a x Line 9
(E) Line 8b x Line 10

Docket No. 110007-EI
Progress Energy Florida
Witness: Will Garrett
Exhibit No. __(WG-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2010 through December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: SEA TURTLE - COASTAL STREET LIGHTING - (Project 9)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual January 10	Actual February 10	Actual March 10	Actual April 10	Actual May 10	Actual June 10	Actual July 10	Actual August 10	Actual September 10	Actual October 10	Actual November 10	Actual December 10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$51	$2	$0	$0	$0	$0	$0	$0	$0	$0	$53
	b. Clearings to Plant			0	0	51	2	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$10,146	10,146	10,146	10,197	10,199	10,199	10,199	10,199	10,199	10,199	10,199	10,199	10,199	
3	Less: Accumulated Depreciation		(700)	(726)	(752)	(778)	(804)	(830)	(856)	(882)	(908)	(934)	(960)	(986)	(1,012)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$9,446	9,420	9,394	9,419	9,395	9,369	9,343	9,317	9,291	9,265	9,239	9,213	9,187	
6	Average Net Investment			9,433	9,407	9,407	9,407	9,382	9,356	9,330	9,304	9,278	9,252	9,226	9,200	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		23	23	23	23	23	23	23	23	23	23	23	23	$276
	b. Equity Component Grossed Up For Taxes	8.02%		63	63	63	63	63	63	62	62	62	62	62	62	750
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C) 3.10%			26	26	26	26	26	26	26	26	26	26	26	26	312
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.009673			8	8	8	8	8	8	8	8	8	8	8	8	96
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			120	120	120	120	120	120	119	119	119	119	119	119	1,434
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			120	120	120	120	120	120	119	119	119	119	119	119	1,434
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - (Distribution)			0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			120	120	120	120	120	120	119	119	119	119	119	119	1,429
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$120	$120	$120	$120	$120	$120	$119	$119	$119	$119	$119	$119	$1,429

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2009 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Witness: Will Garrett
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2010 through December 2010

Form 42-8A
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Return on Capital Investments, Depreciation and Taxes
For Project: UNDERGROUND STORAGE TANKS - BASE (Project 10.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 10	Actual February 10	Actual March 10	Actual April 10	Actual May 10	Actual June 10	Actual July 10	Actual August 10	Actual September 10	Actual October 10	Actual November 10	Actual December 10	End of Period Total
	1 Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
	2 Plant-in-Service/Depreciation Base		$168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	
	3 Less: Accumulated Depreciation		(14,032)	(14,328)	(14,624)	(14,920)	(15,216)	(15,512)	(15,808)	(16,104)	(16,400)	(16,696)	(16,992)	(17,288)	(17,584)	
	4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
	5 Net Investment (Lines 2 + 3 + 4)		$154,909	154,613	154,317	154,021	153,725	153,429	153,133	152,837	152,541	152,245	151,949	151,653	151,357	
	6 Average Net Investment			154,761	154,465	154,169	153,873	153,577	153,281	152,985	152,689	152,393	152,097	151,801	151,505	
	7 Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		381	380	379	379	378	377	376	376	375	374	373	373	$4,521
	b. Equity Component Grossed Up For Taxes	8.02%		1,035	1,033	1,031	1,029	1,027	1,025	1,023	1,021	1,019	1,017	1,015	1,013	12,288
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
	8 Investment Expenses															
	a. Depreciation (C) 2.10%			296	296	296	296	296	296	296	296	296	296	296	296	3,552
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.010800			152	152	152	152	152	152	152	152	152	152	152	152	1,824
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
	9 Total System Recoverable Expenses (Lines 7 + 8)			1,864	1,861	1,858	1,856	1,853	1,850	1,847	1,845	1,842	1,839	1,836	1,834	22,185
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,864	1,861	1,858	1,856	1,853	1,850	1,847	1,845	1,842	1,839	1,836	1,834	22,185
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			1,698	1,695	1,692	1,691	1,688	1,685	1,682	1,681	1,678	1,675	1,672	1,671	20,208
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$1,698	$1,695	$1,692	$1,691	$1,688	$1,685	$1,682	$1,681	$1,678	$1,675	$1,672	$1,671	$20,208

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Oder PSC-10-0131-FOF-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. *Based on 2009 Effective Tax Rate on original cost.*
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 110007-EI
Progress Energy Florida
Witness: Will Garrett
Exhibit No. __ (WG-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2010 through December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: UNDERGROUND STORAGE TANKS - INTERMEDIATE (10.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 10	Actual February 10	Actual March 10	Actual April 10	Actual May 10	Actual June 10	Actual July 10	Actual August 10	Actual September 10	Actual October 10	Actual November 10	Actual December 10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	
3	Less: Accumulated Depreciation		(7,169)	(7,372)	(7,575)	(7,778)	(7,981)	(8,184)	(8,387)	(8,590)	(8,793)	(8,996)	(9,199)	(9,402)	(9,605)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$68,837	68,634	68,431	68,228	68,025	67,822	67,619	67,416	67,213	67,010	66,807	66,604	66,401	
6	Average Net Investment			68,736	68,533	68,330	68,127	67,924	67,721	67,518	67,315	67,112	66,909	66,706	66,503	
7	Return on Average Net Investment (B)															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		169	169	168	168	167	167	166	166	165	165	164	164	$1,998
	b. Equity Component Grossed Up For Taxes	8.02%		460	458	457	456	454	453	451	450	449	447	446	445	5,426
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C) 3.20%			203	203	203	203	203	203	203	203	203	203	203	203	2,436
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.009330			59	59	59	59	59	59	59	59	59	59	59	59	708
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			891	889	887	886	883	882	879	878	876	874	872	871	10,568
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			891	889	887	886	883	882	879	878	876	874	872	871	10,568
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)			0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	0.58962	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			525	524	523	522	521	520	518	518	517	515	514	514	6,231
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$525	$524	$523	$522	$521	$520	$518	$518	$517	$515	$514	$514	$6,231

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2009 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 110007-EI
Progress Energy Florida
Witness: Will Garrett
Exhibit No. __ (WG-1)

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2010 through December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: MODULAR COOLING TOWERS - BASE (Project 11)
(in Dollars)

Line / Description	Beginning of Period Amount	Actual January 10	Actual February 10	Actual March 10	Actual April 10	Actual May 10	Actual June 10	Actual July 10	Actual August 10	Actual September 10	Actual October 10	Actual November 10	Actual December 10	End of Period Total
1 Investments														
a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
d. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base	$665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	
3 Less: Accumulated Depreciation	(467,179)	(468,265)	(479,351)	(490,437)	(501,523)	(512,609)	(523,695)	(534,781)	(545,867)	(556,953)	(568,039)	(579,125)	(590,211)	
4 CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)	$207,961	196,875	185,789	174,703	163,617	152,531	141,445	130,359	119,273	108,187	97,101	86,015	74,929	
6 Average Net Investment		202,418	191,332	180,246	169,160	158,074	146,988	135,902	124,816	113,730	102,644	91,558	80,472	
7 Return on Average Net Investment (B)														
a. Debt Component (Line 6 x 2.95% x 1/12) 2.95%		498	471	443	416	389	362	334	307	280	253	225	198	$4,176
b. Equity Component Grossed Up For Taxes 8.02%		1,353	1,279	1,205	1,131	1,057	983	909	835	760	686	612	538	11,348
c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses														
a. Depreciation (C) 20.00%		11,086	11,086	11,086	11,086	11,086	11,086	11,086	11,086	11,086	11,086	11,086	11,086	133,032
b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes (D) 0.010800		599	599	599	599	599	599	599	599	599	599	599	599	7,188
e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)		13,536	13,435	13,333	13,232	13,131	13,030	12,928	12,827	12,725	12,624	12,522	12,421	155,744
a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand		13,536	13,435	13,333	13,232	13,131	13,030	12,928	12,827	12,725	12,624	12,522	12,421	155,744
10 Energy Jurisdictional Factor		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11 Demand Jurisdictional Factor - Production (Base)		0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	
12 Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13 Retail Demand-Related Recoverable Costs (F)		12,330	12,238	12,145	12,053	11,961	11,869	11,776	11,684	11,591	11,499	11,406	11,314	141,866
14 Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$12,330	$12,238	$12,145	$12,053	$11,961	$11,869	$11,776	$11,684	$11,591	$11,499	$11,406	$11,314	$141,866

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.50%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Line 2 x rate x 1/12. Depreciation rate based on 5 year life of project, as stated in Dkt. 080162-EI.
(D) Line 2 x rate x 1/12. Based on 2009 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-up Amount
January 2010 through December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Crystal River Thermal Discharge Compliance Project - AFUDC - Base (Project 11.1)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January 10	Actual February 10	Actual March 10	Actual April 10	Actual May 10	Actual June 10	Actual July 10	Actual August 10	Actual September 10	Actual October 10	Actual November 10	Actual December 10	End of Period Total
1	Investments														
	a. Expenditures/Additions		$245,841	$377,734	$357,741	$539,214	$2,260,108	$708,135	$712,736	$41,211	$27,506	$2,782,060	$57,999	$314,142	$8,424,448
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)		40,918	42,539	45,651	49,848	69,020	61,093	68,688	71,226	72,030	80,238	88,220	84,095	
2	Plant-in-Service/Depreciation Base	$361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	
3	Less: Accumulated Depreciation	(2,434)	(2,946)	(3,458)	(3,970)	(4,482)	(4,994)	(5,506)	(6,018)	(6,530)	(7,042)	(7,554)	(8,066)	(8,578)	
4	CWIP - AFUDC-Interest Bearing	6,619,164	6,905,923	7,326,197	7,729,589	8,318,649	10,647,777	11,417,005	12,198,428	12,239,639	12,267,145	15,049,226	15,107,225	15,421,367	
5	Net Investment (Lines 2 + 3 + 4)	$6,978,466	7,264,713	7,684,474	8,087,354	8,675,902	11,004,518	11,773,234	12,554,146	12,594,845	12,621,839	15,403,407	15,460,894	15,774,525	
6	Average Net Investment (B)		359,046	358,534	358,022	357,510	356,998	356,486	355,974	355,462	354,950	354,438	353,926	353,414	
7	Return on Average Net Investment (C)														
	a. Debt Component (Line 6 x 2.95% x 1/12) 2.95%		883	882	881	880	878	877	876	875	873	872	871	870	$10,518
	b. Equity Component Grossed Up For Taxes 8.02%		2,401	2,397	2,394	2,390	2,387	2,384	2,380	2,377	2,373	2,370	2,366	2,363	28,582
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation (D)		512	512	512	512	512	512	512	512	512	512	512	512	6,144
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	N/A
	d. Property Taxes (E) 0.010800		330	330	330	330	330	330	330	330	330	330	330	330	3,960
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		4,126	4,121	4,117	4,112	4,107	4,103	4,098	4,094	4,088	4,084	4,079	4,075	49,204
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		4,126	4,121	4,117	4,112	4,107	4,103	4,098	4,094	4,088	4,084	4,079	4,075	49,204
10	Energy Jurisdictional Factor		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)		0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	0.91089	
12	Retail Energy-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (G)		3,758	3,754	3,750	3,746	3,741	3,737	3,733	3,729	3,724	3,720	3,716	3,712	44,819
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$3,758	$3,754	$3,750	$3,746	$3,741	$3,737	$3,733	$3,729	$3,724	$3,720	$3,716	$3,712	$44,819

Notes:

(A) AFUDC rate reflected within Docket 100134-EI per Order PSC-10-0258-PCO-EI.
(B) Line represents the Average Net Investment excluding AFUDC interest-bearing CWIP projects. Refer to Capital Program Detail for Average Net Investment Return on which Line 7 is calculated.
(C) Line 6 x 10.96% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(D) Depreciation calculated only on assets placed in-service which appear in CR Thermal Discharge Project section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(E) Property taxes calculated only on assets placed in-service which appear in CR Thermal Discharge Project section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2009 Effective Tax Rate on original cost.
(F) Line 9a x Line 10

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Form 42 9A

PROGRESS ENERGY FLORIDA

Environmental Cost Recovery Clause (ECRC)

Calculation of the Current Period Estimated/Actual Amount

January 2010 through December 2010

Progress Energy Florida Capital Structure and Cost Rates

Tax Rate

38.575%

Class of Capital	Retail Amount	Stafff Adjusted	Ratio	Cost Rate	Weighted Cost Rate	PreTax Weighted Cost Rate
CE	$ 2,916,026	$ 2,945,782	46.74%	0.10500	4.908%	7.990%
PS	21,239	21,456	0.34%	0.04510	0.015%	0.025%
LTD	2,817,708	2,846,460	45.17%	0.06178	2.790%	2.790%
STD	41,245	41,666	0.66%	0.03720	0.025%	0.025%
CD-Active	144,119	145,590	2.31%	0.05950	0.137%	0.137%
CD-Inactive	1,457	1,472	0.02%	0.00000	0.000%	0.000%
ADIT	415,881	420,125	6.67%	0.00000	0.000%	0.000%
FAS 109	(122,914)	(124,168)	-1.97%	0.00000	0.000%	0.000%
ITC	3,857	3,896	0.06%	0.08360	0.005%	0.008%
Total	$ 6,238,618	$ 6,302,278	100.00%		7.881%	10.976%

Total Debt	2.952%	2.95%
Total Equity	4.928%	8.02%

Source: Per Staff 13-Month Average Capital Structure worksheet - Schedule 2 REVISED - handed out at 1/11/10 Rate Case Agenda - Docket No. 090079-EI

Rationale: The Company is using the currently approved capital structure and cost rates in accordance with the 2010 rate case Order PSC-10-0131-FOF-EI.

Docket No. 110007-EI
Progress Energy Florida
Witness: Will Garrett
Exhibit No. ___(WG-2)

PROGRESS ENERGY FLORIDA, INC.
ENVIRONMENTAL COST RECOVERY
CAPITAL PROGRAM DETAIL

JANUARY 2010 - DECEMBER 2010

DOCKET NO. 110007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 111007-EI EXHIBIT 17
PARTY PROGRESS ENERGY FLORIDA
DESCRIPTION WILL GARRETT (WG-2)
DATE 11/01/11

For Project: PIPELINE INTEGRITY MANAGEMENT - Alderman Road Fence (Project 3.1a)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	
3	Less: Accumulated Depreciation		(5,497)	(5,551)	(5,605)	(5,659)	(5,713)	(5,767)	(5,821)	(5,875)	(5,929)	(5,983)	(6,037)	(6,091)	(6,145)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$28,456	28,402	28,348	28,294	28,240	28,186	28,132	28,078	28,024	27,970	27,916	27,862	27,808	
6	Average Net Investment			28,429	28,375	28,321	28,267	28,213	28,159	28,105	28,051	27,997	27,943	27,889	27,835	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		70	70	70	70	69	69	69	69	69	69	69	68	$831
	b. Equity Component Grossed Up For Taxes	8.02%		190	190	189	189	189	188	188	188	187	187	186	186	2,257
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.90%		54	54	54	54	54	54	54	54	54	54	54	54	648
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008907		25	25	25	25	25	25	25	25	25	25	25	25	300
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			339	339	338	338	337	336	336	336	335	335	334	333	4,036
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			339	339	338	338	337	336	336	336	335	335	334	333	4,036

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Leak Detection (Project 3.1b)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	
3	Less: Accumulated Depreciation		(521,675)	(527,396)	(533,117)	(538,838)	(544,559)	(550,280)	(556,001)	(561,722)	(567,443)	(573,164)	(578,885)	(584,606)	(590,327)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$2,118,961	2,113,240	2,107,519	2,101,798	2,096,077	2,090,356	2,084,635	2,078,914	2,073,193	2,067,472	2,061,751	2,056,030	2,050,309	
6	Average Net Investment			2,116,101	2,110,380	2,104,659	2,098,938	2,093,217	2,087,496	2,081,775	2,076,054	2,070,333	2,064,612	2,058,891	2,053,170	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		5,208	5,192	5,178	5,164	5,150	5,136	5,122	5,108	5,094	5,080	5,066	5,051	$61,547
	b. Equity Component Grossed Up For Taxes	8.02%		14,149	14,110	14,072	14,034	13,996	13,957	13,919	13,881	13,843	13,804	13,766	13,728	167,259
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.60%		5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	68,652
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008907		1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	1,960	23,520
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			27,036	26,983	26,931	26,879	26,827	26,774	26,722	26,670	26,618	26,565	26,513	26,460	320,978
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			27,036	26,983	26,931	26,879	26,827	26,774	26,722	26,670	26,618	26,565	26,513	26,460	320,978

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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2010 through December 2010
Pipeline Integrity Management (Project 3 Recap)

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Controls Upgrade (Project 3.1c)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$905,147	905,147	905,147	905,147	905,147	905,147	905,147	905,147	905,147	905,147	905,147	905,147	905,147	
3	Less: Accumulated Depreciation		(38,236)	(40,197)	(42,158)	(44,119)	(46,080)	(48,041)	(50,002)	(51,963)	(53,924)	(55,885)	(57,846)	(59,807)	(61,768)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$866,911	864,950	862,989	861,028	859,067	857,106	855,145	853,184	851,223	849,262	847,301	845,340	843,379	
6	Average Net Investment			865,931	863,970	862,009	860,048	858,087	856,126	854,165	852,204	850,243	848,282	846,321	844,360	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		2,130	2,126	2,121	2,116	2,111	2,106	2,102	2,097	2,092	2,087	2,082	2,077	$25,247
	b. Equity Component Grossed Up For Taxes	8.02%		5,790	5,777	5,764	5,750	5,737	5,724	5,711	5,698	5,685	5,672	5,659	5,646	68,613
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation 2.60%			1,961	1,961	1,961	1,961	1,961	1,961	1,961	1,961	1,961	1,961	1,961	1,961	23,532
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.008907			672	672	672	672	672	672	672	672	672	672	672	672	8,064
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			10,553	10,536	10,518	10,499	10,481	10,463	10,446	10,428	10,410	10,392	10,374	10,356	125,456
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			10,553	10,536	10,518	10,499	10,481	10,463	10,446	10,428	10,410	10,392	10,374	10,356	125,456

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For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - TURNER CTs (Project 4.1a)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$5,203	$6,439	$355	$1	$0	$4,598	$19	$0	$0	$0	$0	$147	$16,762
	b. Clearings to Plant			86,013	6,439	355	1	0	4,598	19	0	0	0	0	147	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$1,954,499	2,040,512	2,046,951	2,047,306	2,047,307	2,047,307	2,051,905	2,051,924	2,051,924	2,051,924	2,051,924	2,051,924	2,052,071	
3	Less: Accumulated Depreciation		(35,776)	(40,835)	(45,910)	(50,986)	(56,062)	(61,138)	(66,225)	(71,312)	(76,399)	(81,486)	(86,573)	(91,660)	(96,747)	
4	CWIP - Non-Interest Bearing		86,810	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$1,999,534	1,999,677	2,001,041	1,996,320	1,991,245	1,986,169	1,985,680	1,980,612	1,975,525	1,970,438	1,965,351	1,960,264	1,955,324	
6	Average Net Investment			1,999,605	2,000,359	1,998,681	1,993,783	1,988,707	1,985,925	1,983,146	1,978,069	1,972,982	1,967,895	1,962,808	1,957,794	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		4,920	4,922	4,917	4,905	4,893	4,886	4,879	4,867	4,854	4,842	4,829	4,817	$58,531
	b. Equity Component Grossed Up For Taxes	8.02%		13,370	13,375	13,364	13,331	13,297	13,278	13,260	13,226	13,192	13,158	13,124	13,090	159,065
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.98%		5,059	5,075	5,076	5,076	5,076	5,087	5,087	5,087	5,087	5,087	5,087	5,087	60,971
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010220		1,738	1,743	1,744	1,744	1,744	1,748	1,748	1,748	1,748	1,748	1,748	1,748	20,949
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			25,087	25,115	25,101	25,056	25,010	24,999	24,974	24,928	24,881	24,835	24,788	24,742	299,516
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			25,087	25,115	25,101	25,056	25,010	24,999	24,974	24,928	24,881	24,835	24,788	24,742	299,516

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BARTOW CTs (Project 4.1b)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$160,866	$267,686	$187,420	$5,241	$13	$0	$0	$0	$0	$0	$0	$0	$621,231
	b. Clearings to Plant			0	0	1,314,849	5,241	13	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$153,698	153,698	153,698	1,468,547	1,473,788	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	
3	Less: Accumulated Depreciation		(35,684)	(36,068)	(36,452)	(38,287)	(41,971)	(45,656)	(49,341)	(53,026)	(56,711)	(60,396)	(64,081)	(67,766)	(71,451)	
4	CWIP - Non-Interest Bearing		698,872	859,740	1,127,428	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$816,887	977,371	1,244,675	1,430,260	1,431,817	1,428,145	1,424,460	1,420,775	1,417,090	1,413,405	1,409,720	1,406,035	1,402,350	
6	Average Net Investment			897,129	1,111,023	1,337,467	1,431,038	1,429,981	1,426,303	1,422,618	1,418,933	1,415,248	1,411,563	1,407,878	1,404,193	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		2,207	2,733	3,291	3,521	3,518	3,509	3,500	3,491	3,482	3,473	3,464	3,455	$39,644
	b. Equity Component Grossed Up For Taxes	8.02%		5,998	7,429	8,943	9,568	9,561	9,537	9,512	9,487	9,463	9,438	9,413	9,389	107,738
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.00%		384	384	1,836	3,684	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	35,768
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.000330		120	120	1,142	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	1,146	11,696
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			8,709	10,666	15,212	17,919	17,910	17,877	17,843	17,809	17,776	17,742	17,708	17,675	194,846
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			8,709	10,666	15,212	17,919	17,910	17,877	17,843	17,809	17,776	17,742	17,708	17,675	194,846

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2010 through December 2010
Above Ground Tank Secondary Containment (Projects 4.1 - 4.3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 1 & 2 (Project 4.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	
3	Less: Accumulated Depreciation		(8,547)	(8,649)	(8,751)	(8,853)	(8,955)	(9,057)	(9,159)	(9,261)	(9,363)	(9,465)	(9,567)	(9,669)	(9,771)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$24,545	24,443	24,341	24,239	24,137	24,035	23,933	23,831	23,729	23,627	23,525	23,423	23,321	
6	Average Net Investment			24,494	24,392	24,290	24,188	24,086	23,984	23,882	23,780	23,678	23,576	23,474	23,372	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		60	60	60	60	59	59	59	59	58	58	58	58	$708
	b. Equity Component Grossed Up For Taxes	8.02%		164	163	162	162	161	160	160	159	158	158	157	156	1,920
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation 3.70%			102	102	102	102	102	102	102	102	102	102	102	102	1,224
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.010880			30	30	30	30	30	30	30	30	30	30	30	30	360
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			356	355	354	354	352	351	351	350	348	348	347	346	4,212
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			356	355	354	354	352	351	351	350	348	348	347	346	4,212

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - INTERCESSION CITY CTs (Project 4.1c)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	c. Retirements			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
	d. Other			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
2	Plant-in-Service/Depreciation Base		$1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	
3	Less: Accumulated Depreciation		(176,123)	(185,262)	(194,401)	(203,540)	(212,679)	(221,818)	(230,957)	(240,096)	(249,235)	(258,374)	(267,513)	(276,652)	(285,791)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$1,485,541	1,476,402	1,467,263	1,458,124	1,448,985	1,439,846	1,430,707	1,421,568	1,412,429	1,403,290	1,394,151	1,385,012	1,375,873	
6	Average Net Investment			1,480,972	1,471,833	1,462,694	1,453,555	1,444,416	1,435,277	1,426,138	1,416,999	1,407,860	1,398,721	1,389,582	1,380,443	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		3,644	3,621	3,599	3,576	3,554	3,531	3,509	3,486	3,464	3,441	3,419	3,396	$42,240
	b. Equity Component Grossed Up For Taxes	8.02%		9,902	9,841	9,780	9,719	9,658	9,597	9,536	9,474	9,413	9,352	9,291	9,230	114,792
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation 6.60%			9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	109,668
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.007960			1,102	1,102	1,102	1,102	1,102	1,102	1,102	1,102	1,102	1,102	1,102	1,102	13,224
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			23,787	23,703	23,620	23,536	23,453	23,369	23,286	23,201	23,118	23,034	22,951	22,867	279,924
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			23,787	23,703	23,620	23,536	23,453	23,369	23,286	23,201	23,118	23,034	22,951	22,867	279,924

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - AVON PARK CTs (Project 4.1d)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1 Investments															
a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		$178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	
3 Less: Accumulated Depreciation		(21,161)	(21,877)	(22,593)	(23,309)	(24,025)	(24,741)	(25,457)	(26,173)	(26,889)	(27,605)	(28,321)	(29,037)	(29,753)	
4 CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5 Net Investment (Lines 2 + 3 + 4)		$157,777	157,061	156,345	155,629	154,913	154,197	153,481	152,765	152,049	151,333	150,617	149,901	149,185	
6 Average Net Investment			157,419	156,703	155,987	155,271	154,555	153,839	153,123	152,407	151,691	150,975	150,259	149,543	
7 Return on Average Net Investment															
a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		387	386	384	382	380	378	377	375	373	371	370	368	$4,531
b. Equity Component Grossed Up For Taxes	8.02%		1,053	1,048	1,043	1,038	1,033	1,029	1,024	1,019	1,014	1,009	1,005	1,000	12,315
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	4.80%		716	716	716	716	716	716	716	716	716	716	716	716	8,592
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	[illegible]		132	132	132	132	132	132	132	132	132	132	132	132	1,584
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			2,288	2,282	2,275	2,268	2,261	2,255	2,249	2,242	2,235	2,228	2,223	2,216	27,022
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			2,288	2,282	2,275	2,268	2,261	2,255	2,249	2,242	2,235	2,228	2,223	2,216	27,022

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BAYBORO CTs (Project 4.1e)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1 Investments															
a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		$730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	
3 Less: Accumulated Depreciation		(45,596)	(47,422)	(49,248)	(51,074)	(52,900)	(54,726)	(56,552)	(58,378)	(60,204)	(62,030)	(63,856)	(65,682)	(67,508)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$684,699	682,873	681,047	679,221	677,395	675,569	673,743	671,917	670,091	668,265	666,439	664,613	662,787	
6 Average Net Investment			683,786	681,960	680,134	678,308	676,482	674,656	672,830	671,004	669,178	667,352	665,526	663,700	
7 Return on Average Net Investment															
a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		1,682	1,678	1,673	1,669	1,664	1,660	1,655	1,651	1,646	1,642	1,637	1,633	$19,890
b. Equity Component Grossed Up For Taxes	8.02%		4,572	4,560	4,547	4,535	4,523	4,511	4,499	4,486	4,474	4,462	4,450	4,438	54,057
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	3.00%		1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	21,912
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.009336		568	568	568	568	568	568	568	568	568	568	568	568	6,816
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			8,648	8,632	8,614	8,598	8,581	8,565	8,548	8,531	8,514	8,498	8,481	8,465	102,675
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			8,648	8,632	8,614	8,598	8,581	8,565	8,548	8,531	8,514	8,498	8,481	8,465	102,675

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Witness: Will Garrett
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For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - SUWANNEE CTs (Project 4.1f)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	
3	Less: Accumulated Depreciation		(84,360)	(87,212)	(90,064)	(92,916)	(95,768)	(98,620)	(101,472)	(104,324)	(107,176)	(110,028)	(112,880)	(115,732)	(118,584)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$952,839	949,987	947,135	944,283	941,431	938,579	935,727	932,875	930,023	927,171	924,319	921,467	918,615	
6	Average Net Investment			951,413	948,561	945,709	942,857	940,005	937,153	934,301	931,449	928,597	925,745	922,893	920,041	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		2,341	2,334	2,327	2,320	2,313	2,306	2,299	2,292	2,285	2,278	2,271	2,264	$27,630
	b. Equity Component Grossed Up For Taxes	8.02%		6,361	6,342	6,323	6,304	6,285	6,266	6,247	6,228	6,209	6,190	6,171	6,152	75,078
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation 3.30%			2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	34,224
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.007460			645	645	645	645	645	645	645	645	645	645	645	645	7,740
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			12,199	12,173	12,147	12,121	12,095	12,069	12,043	12,017	11,991	11,965	11,939	11,913	144,672
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			12,199	12,173	12,147	12,121	12,095	12,069	12,043	12,017	11,991	11,965	11,939	11,913	144,672

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - DeBARY CTs (Project 4.1g)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$2,394,294	2,394,294	2,394,294	2,394,294	2,394,294	2,394,294	2,394,294	2,394,294	2,394,294	2,394,294	2,394,294	2,394,294	2,394,294	
3	Less: Accumulated Depreciation		(38,022)	(43,210)	(48,398)	(53,586)	(58,774)	(63,962)	(69,150)	(74,338)	(79,526)	(84,714)	(89,902)	(95,090)	(100,278)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$2,356,272	2,351,084	2,345,896	2,340,708	2,335,520	2,330,332	2,325,144	2,319,956	2,314,768	2,309,580	2,304,392	2,299,204	2,294,016	
6	Average Net Investment			2,353,678	2,348,490	2,343,302	2,338,114	2,332,926	2,327,738	2,322,550	2,317,362	2,312,174	2,306,986	2,301,798	2,296,610	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		5,791	5,778	5,765	5,752	5,740	5,727	5,714	5,701	5,689	5,676	5,663	5,650	$68,646
	b. Equity Component Grossed Up For Taxes	8.02%		15,737	15,702	15,668	15,633	15,598	15,564	15,529	15,494	15,460	15,425	15,390	15,356	186,556
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation 2.60%			5,188	5,188	5,188	5,188	5,188	5,188	5,188	5,188	5,188	5,188	5,188	5,188	62,256
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.010220			2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039	2,039	24,468
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			28,755	28,707	28,660	28,612	28,565	28,518	28,470	28,422	28,376	28,328	28,280	28,233	341,926
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			28,755	28,707	28,660	28,612	28,565	28,518	28,470	28,422	28,376	28,328	28,280	28,233	341,926

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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2010 through December 2010
Above Ground Tank Secondary Containment (Projects 4.1 - 4.3 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - University of Florida (Project 4.1h)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	
3	Less: Accumulated Depreciation		(37,326)	(37,562)	(37,798)	(38,034)	(38,270)	(38,506)	(38,742)	(38,978)	(39,214)	(39,450)	(39,686)	(39,922)	(40,158)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$104,109	103,872	103,636	103,400	103,164	102,928	102,692	102,456	102,220	101,984	101,748	101,512	101,276	
6	Average Net Investment			103,990	103,754	103,518	103,282	103,046	102,810	102,574	102,338	102,102	101,866	101,630	101,394	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		256	255	255	254	254	253	252	252	251	251	250	249	$3,032
	b. Equity Component Grossed Up For Taxes	8.02%		695	694	692	691	689	687	686	684	683	681	680	678	8,240
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.00%		236	236	236	236	236	236	236	236	236	236	236	236	2,832
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.014780		174	174	174	174	174	174	174	174	174	174	174	174	2,088
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,361	1,359	1,357	1,355	1,353	1,350	1,348	1,346	1,344	1,342	1,340	1,337	16,192
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,361	1,359	1,357	1,355	1,353	1,350	1,348	1,346	1,344	1,342	1,340	1,337	16,192

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Anclote (Project 4.3)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	
3	Less: Accumulated Depreciation		($22,218)	(22,750)	(23,282)	(23,814)	(24,346)	(24,878)	(25,410)	(25,942)	(26,474)	(27,006)	(27,538)	(28,070)	(28,602)	
4	CWIP - Non-Interest Bearing		$0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$268,080	267,548	267,016	266,484	265,952	265,420	264,888	264,356	263,824	263,292	262,760	262,228	261,696	
6	Average Net Investment			267,814	267,282	266,750	266,218	265,686	265,154	264,622	264,090	263,558	263,026	262,494	261,962	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		659	658	656	655	654	652	651	650	648	647	646	645	$7,821
	b. Equity Component Grossed Up For Taxes	8.02%		1,791	1,787	1,784	1,780	1,776	1,773	1,769	1,766	1,762	1,759	1,755	1,752	21,254
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.20%		532	532	532	532	532	532	532	532	532	532	532	532	6,384
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007440		180	180	180	180	180	180	180	180	180	180	180	180	2,160
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			3,162	3,157	3,152	3,147	3,142	3,137	3,132	3,128	3,122	3,118	3,113	3,109	37,619
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			3,162	3,157	3,152	3,147	3,142	3,137	3,132	3,128	3,122	3,118	3,113	3,109	37,619

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For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 4 & 5 (Project 4.2a)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$28,322	$75	$28,397
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	28,322	75	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$2,816,320	2,816,320	2,816,320	2,816,320	2,816,320	2,816,320	2,816,320	2,816,320	2,816,320	2,816,320	2,816,320	2,844,642	2,844,718	
3	Less: Accumulated Depreciation		(63,033)	(68,900)	(74,767)	(80,634)	(86,501)	(92,368)	(98,235)	(104,102)	(109,969)	(115,836)	(121,703)	(127,629)	(133,555)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$2,753,288	2,747,421	2,741,554	2,735,687	2,729,820	2,723,953	2,718,086	2,712,219	2,706,352	2,700,485	2,694,618	2,717,014	2,711,164	
6	Average Net Investment			2,750,355	2,744,488	2,738,621	2,732,754	2,726,887	2,721,020	2,715,153	2,709,286	2,703,419	2,697,552	2,705,816	2,714,089	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		6,767	6,752	6,738	6,723	6,709	6,695	6,680	6,666	6,651	6,637	6,657	6,678	$80,353
	b. Equity Component Grossed Up For Taxes	8.02%		18,389	18,350	18,311	18,272	18,232	18,193	18,154	18,115	18,076	18,036	18,092	18,147	218,367
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation 2.50%			5,867	5,867	5,867	5,867	5,867	5,867	5,867	5,867	5,867	5,867	5,926	5,926	70,522
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.010800			2,535	2,536	2,536	2,535	2,536	2,536	2,536	2,536	2,536	2,535	2,560	2,560	30,470
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			33,558	33,504	33,451	33,397	33,343	33,290	33,236	33,183	33,129	33,075	33,235	33,311	399,712
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			33,558	33,504	33,451	33,397	33,343	33,290	33,236	33,183	33,129	33,075	33,235	33,311	399,712

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Higgins (Project 4.1i)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	
3	Less: Accumulated Depreciation		(11,796)	(13,573)	(15,350)	(17,127)	(18,904)	(20,681)	(22,458)	(24,235)	(26,012)	(27,789)	(29,566)	(31,343)	(33,120)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$383,172	381,395	379,618	377,841	376,064	374,287	372,510	370,733	368,956	367,179	365,402	363,625	361,848	
6	Average Net Investment			382,283	380,506	378,729	376,952	375,175	373,398	371,621	369,844	368,067	366,290	364,513	362,736	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		941	936	932	927	923	919	914	910	906	901	897	892	$10,998
	b. Equity Component Grossed Up For Taxes	8.02%		2,556	2,544	2,532	2,520	2,508	2,497	2,485	2,473	2,461	2,449	2,437	2,425	29,887
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation 5.40%			1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	21,324
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.009330			307	307	307	307	307	307	307	307	307	307	307	307	3,684
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			5,581	5,564	5,548	5,531	5,515	5,500	5,483	5,467	5,451	5,434	5,418	5,401	65,893
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			5,581	5,564	5,548	5,531	5,515	5,500	5,483	5,467	5,451	5,434	5,418	5,401	65,893

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For Project: CAIR CTs - AVON PARK (Project 7.2a)
(in Dollars)

ALL Peaking

Line Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1 Investments															
a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		$161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	
3 Less: Accumulated Depreciation		(4,553)	(4,957)	(5,361)	(5,765)	(6,169)	(6,573)	(6,977)	(7,381)	(7,785)	(8,189)	(8,593)	(8,997)	(9,401)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$157,201	156,797	156,393	155,989	155,585	155,181	154,777	154,373	153,969	153,565	153,161	152,757	152,353	
6 Average Net Investment			156,999	156,595	156,191	155,787	155,383	154,979	154,575	154,171	153,767	153,363	152,959	152,555	
7 Return on Average Net Investment															
a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		386	385	384	383	382	381	380	379	378	377	376	375	$4,566
b. Equity Component Grossed Up For Taxes	8.02%		1,050	1,047	1,044	1,042	1,039	1,036	1,034	1,031	1,028	1,025	1,023	1,020	12,419
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation 3.00%			404	404	404	404	404	404	404	404	404	404	404	404	4,848
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes 0.008880			120	120	120	120	120	120	120	120	120	120	120	120	1,440
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			1,960	1,956	1,952	1,949	1,945	1,941	1,938	1,934	1,930	1,926	1,923	1,919	23,273
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			1,960	1,956	1,952	1,949	1,945	1,941	1,938	1,934	1,930	1,926	1,923	1,919	23,273

For Project: CAIR CTs - BARTOW (Project 7.2b)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1 Investments															
a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		$275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	
3 Less: Accumulated Depreciation		(19,273)	(19,640)	(20,007)	(20,374)	(20,741)	(21,108)	(21,475)	(21,842)	(22,209)	(22,576)	(22,943)	(23,310)	(23,677)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$256,074	255,707	255,340	254,973	254,606	254,239	253,872	253,505	253,138	252,771	252,404	252,037	251,670	
6 Average Net Investment			255,891	255,524	255,157	254,790	254,423	254,056	253,689	253,322	252,955	252,588	252,221	251,854	
7 Return on Average Net Investment															
a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		630	629	628	627	626	625	624	623	622	621	621	620	$7,496
b. Equity Component Grossed Up For Taxes	8.02%		1,711	1,708	1,706	1,704	1,701	1,699	1,696	1,694	1,691	1,689	1,686	1,684	20,369
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation 1.60%			367	367	367	367	367	367	367	367	367	367	367	367	4,404
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes 0.009330			214	214	214	214	214	214	214	214	214	214	214	214	2,568
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			2,922	2,918	2,915	2,912	2,908	2,905	2,901	2,898	2,894	2,891	2,888	2,885	34,837
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			2,922	2,918	2,915	2,912	2,908	2,905	2,901	2,898	2,894	2,891	2,888	2,885	34,837

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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2010 through December 2010
CAIR CTs (Project 7.2 Recap)

For Project: CAIR CTs - BAYBORO (Project 7.2c)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	
3	Less: Accumulated Depreciation		(11,079)	(11,460)	(11,841)	(12,222)	(12,603)	(12,984)	(13,365)	(13,746)	(14,127)	(14,508)	(14,889)	(15,270)	(15,651)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$187,909	187,528	187,147	186,766	186,385	186,004	185,623	185,242	184,861	184,480	184,099	183,718	183,337	
6	Average Net Investment			187,719	187,338	186,957	186,576	186,195	185,814	185,433	185,052	184,671	184,290	183,909	183,528	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		462	461	460	459	458	457	456	455	454	453	452	452	$5,479
	b. Equity Component Grossed Up For Taxes	8.02%		1,256	1,253	1,250	1,247	1,245	1,242	1,240	1,237	1,235	1,232	1,230	1,227	14,893
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.30%		381	381	381	381	381	381	381	381	381	381	381	381	4,572
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009330		155	155	155	155	155	155	155	155	155	155	155	155	1,860
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,253	2,250	2,246	2,242	2,239	2,236	2,232	2,228	2,225	2,221	2,218	2,215	26,804
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			2,253	2,250	2,246	2,242	2,239	2,236	2,232	2,228	2,225	2,221	2,218	2,215	26,804

For Project: CAIR CTs - DeBARY (Project 7.2d)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	
3	Less: Accumulated Depreciation		(6,375)	(6,594)	(6,813)	(7,032)	(7,251)	(7,470)	(7,689)	(7,908)	(8,127)	(8,346)	(8,565)	(8,784)	(9,003)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$81,292	81,073	80,854	80,635	80,416	80,197	79,978	79,759	79,540	79,321	79,102	78,883	78,664	
6	Average Net Investment			81,182	80,963	80,744	80,525	80,306	80,087	79,868	79,649	79,430	79,211	78,992	78,773	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		200	199	199	198	198	197	197	196	195	195	194	194	$2,362
	b. Equity Component Grossed Up For Taxes	8.02%		543	541	540	538	537	536	534	533	531	530	528	527	6,417
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.00%		219	219	219	219	219	219	219	219	219	219	219	219	2,628
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010220		75	75	75	75	75	75	75	75	75	75	75	75	900
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,037	1,034	1,033	1,030	1,029	1,026	1,025	1,023	1,020	1,019	1,016	1,015	12,307
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,037	1,034	1,033	1,030	1,029	1,026	1,025	1,023	1,020	1,019	1,016	1,015	12,307

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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2010 through December 2010
CAIR CTs (Project 7.2 Recap)

For Project: CAIR CTs - HIGGINS (Project 7.2e)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	345,490	
3	Less: Accumulated Depreciation		(6,697)	(7,532)	(8,367)	(9,202)	(10,037)	(10,872)	(11,707)	(12,542)	(13,377)	(14,212)	(15,047)	(15,882)	(16,717)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$338,793	337,958	337,123	336,288	335,453	334,618	333,783	332,948	332,113	331,278	330,443	329,608	328,773	
6	Average Net Investment			338,376	337,541	336,706	335,871	335,036	334,201	333,366	332,531	331,696	330,861	330,026	329,191	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		833	830	828	826	824	822	820	818	816	814	812	810	$9,853
	b. Equity Component Grossed Up For Taxes	8.02%		2,262	2,257	2,251	2,246	2,240	2,235	2,229	2,223	2,218	2,212	2,207	2,201	26,781
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.90%		835	835	835	835	835	835	835	835	835	835	835	835	10,020
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009339		269	269	269	269	269	269	269	269	269	269	269	269	3,228
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			4,199	4,191	4,183	4,176	4,168	4,161	4,153	4,145	4,138	4,130	4,123	4,115	49,882
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			4,199	4,191	4,183	4,176	4,168	4,161	4,153	4,145	4,138	4,130	4,123	4,115	49,882

For Project: CAIR CTs - INTERCESSION CITY (Project 7.2f)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	
3	Less: Accumulated Depreciation		(19,459)	(20,246)	(21,033)	(21,820)	(22,607)	(23,394)	(24,181)	(24,968)	(25,756)	(26,542)	(27,329)	(28,116)	(28,903)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$330,125	329,338	328,551	327,764	326,977	326,190	325,403	324,616	323,829	323,042	322,255	321,468	320,681	
6	Average Net Investment			329,731	328,944	328,157	327,370	326,583	325,796	325,009	324,222	323,436	322,648	321,861	321,074	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		811	809	807	805	803	802	800	798	796	794	792	790	$9,607
	b. Equity Component Grossed Up For Taxes	8.02%		2,205	2,199	2,194	2,189	2,184	2,178	2,173	2,168	2,163	2,157	2,152	2,147	26,109
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.70%		787	787	787	787	787	787	787	787	787	787	787	787	9,444
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007964		232	232	232	232	232	232	232	232	232	232	232	232	2,784
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			4,035	4,027	4,020	4,013	4,006	3,999	3,992	3,985	3,978	3,970	3,963	3,956	47,944
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			4,035	4,027	4,020	4,013	4,006	3,999	3,992	3,985	3,978	3,970	3,963	3,956	47,944

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Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2010 through December 2010
CAIR CTs (Project 7.2 Recap)

For Project: CAIR CTs - TURNER (Project 7.2g)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	
3	Less: Accumulated Depreciation		(7,767)	(7,901)	(8,035)	(8,169)	(8,303)	(8,437)	(8,571)	(8,705)	(8,839)	(8,973)	(9,107)	(9,241)	(9,375)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$126,245	126,111	125,977	125,843	125,709	125,575	125,441	125,307	125,173	125,039	124,905	124,771	124,637	
6	Average Net Investment			126,178	126,044	125,910	125,776	125,642	125,508	125,374	125,240	125,106	124,972	124,838	124,704	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		310	310	310	309	309	309	308	308	308	307	307	307	$3,702
	b. Equity Component Grossed Up For Taxes	8.02%		844	843	842	841	840	839	838	837	836	836	835	834	10,065
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.20%		134	134	134	134	134	134	134	134	134	134	134	134	1,608
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010220		114	114	114	114	114	114	114	114	114	114	114	114	1,368
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,402	1,401	1,400	1,398	1,397	1,396	1,394	1,393	1,392	1,391	1,390	1,389	16,743
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,402	1,401	1,400	1,398	1,397	1,396	1,394	1,393	1,392	1,391	1,390	1,389	16,743

For Project: CAIR CTs - SUWANNEE (Project 7.2h)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	
3	Less: Accumulated Depreciation		(15,822)	(16,235)	(16,648)	(17,061)	(17,474)	(17,887)	(18,300)	(18,713)	(19,126)	(19,539)	(19,952)	(20,365)	(20,778)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$365,738	365,325	364,912	364,499	364,086	363,673	363,260	362,847	362,434	362,021	361,608	361,195	360,782	
6	Average Net Investment			365,531	365,118	364,705	364,292	363,879	363,466	363,053	362,640	362,227	361,814	361,401	360,988	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		899	898	897	896	895	894	893	892	891	890	889	888	$10,722
	b. Equity Component Grossed Up For Taxes	8.02%		2,444	2,441	2,438	2,436	2,433	2,430	2,427	2,425	2,422	2,419	2,416	2,414	29,145
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.30%		413	413	413	413	413	413	413	413	413	413	413	413	4,956
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007460		237	237	237	237	237	237	237	237	237	237	237	237	2,844
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			3,993	3,989	3,985	3,982	3,978	3,974	3,970	3,967	3,963	3,959	3,955	3,952	47,667
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			3,993	3,989	3,985	3,982	3,978	3,974	3,970	3,967	3,963	3,959	3,955	3,952	47,667

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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2010 through December 2010
CAIR/CAMR Crystal River AFUDC (Project 7.4 Recap)

For Project: CAIR Crystal River AFUDC - Access Road and Vehicle Barrier System (Project 7.4a)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$169,105	$304,905	$263,542	$737,551
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$15,381,150	15,381,150	15,381,150	15,381,150	15,381,150	15,381,150	15,381,150	15,381,150	15,381,150	15,381,150	15,381,150	15,381,150	15,381,150	
3	Less: Accumulated Depreciation		(861,865)	(881,091)	(900,317)	(919,543)	(938,769)	(957,995)	(977,221)	(996,447)	(1,015,673)	(1,034,899)	(1,054,125)	(1,073,351)	(1,092,577)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	169,105	474,010	737,551	
5	Net Investment (Lines 2 + 3 + 4)		$14,519,285	14,500,059	14,480,833	14,461,607	14,442,381	14,423,155	14,403,929	14,384,703	14,365,477	14,346,251	14,496,130	14,781,809	15,026,125	
6	Average Net Investment			14,509,672	14,490,446	14,471,220	14,451,994	14,432,768	14,413,542	14,394,316	14,375,090	14,355,864	14,421,190	14,638,969	14,903,967	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		35,698	35,651	35,604	35,556	35,509	35,462	35,415	35,367	35,320	35,481	36,016	36,668	$427,747
	b. Equity Component Grossed Up For Taxes	8.02%		97,014	96,886	96,757	96,629	96,500	96,372	96,243	96,114	95,986	96,423	97,879	99,651	1,162,454
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.50%		19,226	19,226	19,226	19,226	19,226	19,226	19,226	19,226	19,226	19,226	19,226	19,226	230,712
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010800		13,843	13,843	13,843	13,843	13,843	13,843	13,843	13,843	13,843	13,843	13,843	13,843	166,116
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			165,781	165,606	165,430	165,254	165,078	164,903	164,727	164,550	164,375	164,973	166,964	169,388	1,987,029
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			165,781	165,606	165,430	165,254	165,078	164,903	164,727	164,550	164,375	164,973	166,964	169,388	1,987,029

For Project: CAIR Crystal River AFUDC - UNIT 4 LNB/AH (Project 7.4b)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,279,083	$2,279,083
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	2,279,083	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$10,580,200	10,580,200	10,580,200	10,580,200	10,580,200	10,580,200	10,580,200	10,580,200	10,580,200	10,580,200	10,580,200	10,580,200	12,859,283	
3	Less: Accumulated Depreciation		(274,292)	(296,334)	(318,376)	(340,418)	(362,460)	(384,502)	(406,544)	(428,586)	(450,628)	(472,670)	(494,712)	(516,754)	(543,544)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		$10,305,908	10,283,866	10,261,824	10,239,782	10,217,740	10,195,698	10,173,656	10,151,614	10,129,572	10,107,530	10,085,488	10,063,446	12,315,740	
6	Average Net Investment			10,294,887	10,272,845	10,250,803	10,228,761	10,206,719	10,184,677	10,162,635	10,140,593	10,118,551	10,096,509	10,074,467	11,189,593	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		25,329	25,274	25,220	25,166	25,112	25,057	25,003	24,949	24,895	24,841	24,786	27,530	$303,162
	b. Equity Component Grossed Up For Taxes	8.02%		68,833	68,686	68,539	68,391	68,244	68,097	67,949	67,802	67,654	67,507	67,360	74,816	823,878
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		22,042	22,042	22,042	22,042	22,042	22,042	22,042	22,042	22,042	22,042	22,042	26,790	269,252
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010800		9,522	9,522	9,522	9,522	9,522	9,522	9,522	9,522	9,522	9,522	9,522	11,573	116,315
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			125,726	125,524	125,323	125,121	124,920	124,718	124,516	124,315	124,113	123,912	123,710	140,709	1,512,607
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			125,726	125,524	125,323	125,121	124,920	124,718	124,516	124,315	124,113	123,912	123,710	140,709	1,512,607

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2010 through December 2010
CAIR/CAMR Crystal River AFUDC (Project 7.4 Recap)

For Project: CAIR Crystal River AFUDC - Selective Catalytic Reduction CR5 (Project 7.4c)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$46,650	$1,067,428	$700,799	($4,664)	$91,398	$276,823	$1,117,008	($714,059)	($1,031,816)	$21,942	$199,659	$781,000	$2,552,169
	b. Clearings to Plant			$46,650	1,067,428	700,799	(4,664)	91,398	276,823	1,117,008	(714,059)	(1,031,816)	$21,942	199,659	781,000	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$91,577,493	91,624,143	92,691,571	93,392,370	93,387,706	93,479,104	93,755,927	94,872,935	94,158,876	93,127,060	93,149,002	93,348,661	94,129,661	
3	Less: Accumulated Depreciation		(1,409,754)	(1,600,638)	(1,793,745)	(1,988,312)	(2,182,870)	(2,377,618)	(2,572,943)	(2,770,595)	(2,966,759)	(3,160,774)	(3,354,834)	(3,549,310)	(3,745,413)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$90,167,739	90,023,505	90,897,826	91,404,058	91,204,836	91,101,486	91,182,984	92,102,340	91,192,117	89,966,286	89,794,168	89,799,351	90,384,248	
6	Average Net Investment			90,095,622	90,460,665	91,150,942	91,304,447	91,153,161	91,142,235	91,642,662	91,647,229	90,579,202	89,880,227	89,796,760	90,091,800	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		221,663	222,562	224,260	224,637	224,265	224,238	225,470	225,481	222,853	221,133	220,928	221,654	$2,679,144
	b. Equity Component Grossed Up For Taxes	8.82%		602,396	604,836	609,452	610,478	609,467	609,393	612,739	612,770	605,629	600,955	600,397	602,370	7,280,882
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		190,884	193,107	194,567	194,558	194,748	195,325	197,652	196,164	194,015	194,060	194,476	196,103	2,335,659
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010800		82,462	83,422	84,053	84,049	84,131	84,380	85,386	84,743	83,814	83,834	84,014	84,717	1,009,005
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,097,405	1,103,927	1,112,332	1,113,722	1,112,611	1,113,336	1,121,247	1,119,158	1,106,311	1,099,982	1,099,815	1,104,844	13,304,690
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,097,405	1,103,927	1,112,332	1,113,722	1,112,611	1,113,336	1,121,247	1,119,158	1,106,311	1,099,982	1,099,815	1,104,844	13,304,690

For Project: CAIR Crystal River AFUDC - FGD Common (Project 7.4d)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$420,817	($1,576,956)	$14,450,736	$11,323,064	$361	$551,847	($5,182,335)	($4,816,559)	($14,571,971)	($1,903,144)	($84,513)	($334,852)	($1,723,507)
	b. Clearings to Plant			420,817	(1,576,956)	14,450,736	11,323,064	361	551,847	(5,182,335)	(4,816,559)	(14,571,971)	(1,903,144)	(84,513)	(334,852)	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$617,790,388	618,211,204	616,634,248	631,084,984	642,408,047	642,408,408	642,960,255	637,777,920	632,961,360	618,389,389	616,486,245	616,401,732	616,066,880	
3	Less: Accumulated Depreciation		(728,478)	(2,016,418)	(3,301,073)	(4,615,833)	(5,954,183)	(7,292,534)	(8,632,035)	(9,960,739)	(11,279,409)	(12,567,720)	(13,852,066)	(15,136,236)	(16,419,709)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$617,061,910	616,194,786	613,333,175	626,469,151	636,453,864	635,115,874	634,328,220	627,817,181	621,681,951	605,821,669	602,634,179	601,265,496	599,647,171	
6	Average Net Investment			616,628,348	614,763,981	619,901,163	631,461,508	635,784,869	634,722,047	631,072,700	624,749,566	613,751,810	604,227,924	601,949,837	600,456,334	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		1,517,098	1,512,511	1,525,151	1,553,593	1,564,229	1,561,615	1,552,636	1,537,079	1,510,021	1,486,589	1,480,985	1,477,310	$18,278,817
	b. Equity Component Grossed Up For Taxes	8.82%		4,122,889	4,110,423	4,144,771	4,222,066	4,250,973	4,243,867	4,219,466	4,177,189	4,103,656	4,039,977	4,024,746	4,014,760	49,674,783
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		1,287,940	1,284,655	1,314,760	1,338,350	1,338,351	1,339,501	1,328,704	1,318,670	1,288,311	1,284,346	1,284,170	1,283,473	15,691,231
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010800		556,390	554,971	567,976	578,167	578,168	578,664	574,000	569,665	556,550	554,838	554,762	554,460	6,778,611
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			7,484,317	7,462,560	7,552,658	7,692,176	7,731,721	7,723,647	7,674,806	7,602,603	7,458,538	7,365,750	7,344,663	7,330,003	90,423,442
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			7,484,317	7,462,560	7,552,658	7,692,176	7,731,721	7,723,647	7,674,806	7,602,603	7,458,538	7,365,750	7,344,663	7,330,003	90,423,442

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2010 through December 2010
CAIR/CAMR Crystal River AFUDC (Project 7.4 Recap)

For Project: CAIR Crystal River AFUDC - SCR Common Items (Project 7.4e)
(in Dollars)

Line	Description	Rate	Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			($13,583)	$0	$0	$0	$0	$0	$0	$0	$54,120	$89	$0	($54,120)	($13,494)
	b. Clearings to Plant			(13,583)	0	0	0	0	0	0	0	54,120	89	0	(54,120)	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$61,273,808	61,260,225	61,260,225	61,260,225	61,260,225	61,260,225	61,260,225	61,260,225	61,260,225	61,314,345	61,314,434	61,314,434	61,260,314	
3	Less: Accumulated Depreciation		(795,621)	(923,246)	(1,050,871)	(1,178,496)	(1,306,121)	(1,433,746)	(1,561,371)	(1,688,996)	(1,816,621)	(1,944,359)	(2,072,097)	(2,199,835)	(2,327,461)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$60,478,187	60,336,979	60,209,354	60,081,729	59,954,104	59,826,479	59,698,854	59,571,229	59,443,604	59,369,986	59,242,337	59,114,599	58,932,853	
6	Average Net Investment			60,407,583	60,273,167	60,145,542	60,017,917	59,890,292	59,762,667	59,635,042	59,507,417	59,406,795	59,306,162	59,178,468	59,023,726	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		148,622	148,291	147,977	147,663	147,349	147,035	146,721	146,407	146,159	145,912	145,598	145,217	$1,762,951
	b. Equity Component Grossed Up For Taxes	8.82%		403,896	402,997	402,144	401,291	400,437	399,584	398,731	397,877	397,205	396,532	395,678	394,643	4,791,015
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		127,625	127,625	127,625	127,625	127,625	127,625	127,625	127,625	127,738	127,738	127,738	127,626	1,531,840
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010800		55,134	55,134	55,134	55,134	55,134	55,134	55,134	55,134	55,183	55,183	55,183	55,134	661,755
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			735,277	734,047	732,880	731,713	730,545	729,378	728,211	727,043	726,285	725,365	724,197	722,620	8,747,561
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			735,277	734,047	732,880	731,713	730,545	729,378	728,211	727,043	726,285	725,365	724,197	722,620	8,747,561

For Project: CAIR Crystal River AFUDC - Flue Gas Desulfurization CR5 (Project 7.4f)
(in Dollars)

Line	Description	Rate	Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$88,118	$15,160	$1,488,696	($160,510)	$1,721,129	$251,031	$151,183	($183,086)	($1,296,362)	($7,404)	$96,378	$595,327	$2,759,659
	b. Clearings to Plant			88,118	15,160	1,488,696	(160,510)	1,721,129	251,031	151,183	(183,086)	(1,296,362)	(7,404)	96,378	595,327	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$133,764,089	133,852,206	133,867,366	135,356,062	135,195,552	136,916,681	137,167,711	137,318,895	137,135,808	135,839,447	135,832,043	135,928,420	136,523,748	
3	Less: Accumulated Depreciation		(157,730)	(436,589)	(715,479)	(997,471)	(1,279,128)	(1,564,371)	(1,850,137)	(2,136,218)	(2,421,918)	(2,704,917)	(2,987,900)	(3,271,084)	(3,555,508)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$133,606,359	133,415,617	133,151,887	134,358,591	133,916,424	135,352,310	135,317,574	135,182,677	134,713,890	133,134,530	132,844,143	132,657,336	132,968,240	
6	Average Net Investment			133,510,988	133,283,752	133,755,239	134,137,507	134,634,367	135,334,942	135,250,126	134,948,284	133,924,210	132,989,336	132,750,740	132,812,788	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		328,479	327,920	329,080	330,020	331,243	332,966	332,758	332,015	329,495	327,195	326,608	326,761	$3,954,540
	b. Equity Component Grossed Up For Taxes	8.82%		892,679	891,159	894,312	896,868	900,190	904,874	904,307	902,289	895,442	889,191	887,595	888,010	10,746,916
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		278,859	278,890	281,992	281,657	285,243	285,766	286,081	285,700	282,999	282,983	283,184	284,424	3,397,778
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010800		120,467	120,481	121,820	121,676	123,225	123,451	123,587	123,422	122,256	122,249	122,336	122,871	1,467,841
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,620,484	1,618,450	1,627,204	1,630,221	1,639,901	1,647,057	1,646,733	1,643,426	1,630,192	1,621,618	1,619,723	1,622,066	19,567,075
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,620,484	1,618,450	1,627,204	1,630,221	1,639,901	1,647,057	1,646,733	1,643,426	1,630,192	1,621,618	1,619,723	1,622,066	19,567,075

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2010 through December 2010
CAIR/CAMR Crystal River AFUDC (Project 7.4 Recap)

For Project: CAIR Crystal River AFUDC - CR5 Sootblower & Intelligent Soot Blowing Controls (Project 7.4g)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1 Investments															
a. Expenditures/Additions			$0	$0	$0	$0	$1,005,002	($60,639)	($94,035)	$0	$0	($131)	$0	$0	$850,198
b. Clearings to Plant			0	0	0	0	1,005,002	(60,639)	(94,035)	0	0	(131)	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		$0	0	0	0	0	1,005,002	944,364	850,329	850,329	850,329	850,198	850,198	850,198	
3 Less: Accumulated Depreciation		0	0	0	0	0	(1,047)	(3,014)	(4,786)	(6,558)	(8,330)	(10,101)	(11,872)	(13,643)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$0	0	0	0	0	1,003,955	941,350	845,543	843,771	841,999	840,097	838,326	836,555	
6 Average Net Investment			0	0	0	0	501,978	972,653	893,446	844,657	842,885	841,048	839,211	837,440	
7 Return on Average Net Investment															
a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		0	0	0	0	1,235	2,393	2,198	2,078	2,074	2,069	2,065	2,060	$16,172
b. Equity Component Grossed Up For Taxes	8.02%		0	0	0	0	3,356	6,503	5,974	5,648	5,636	5,623	5,611	5,599	43,950
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	2.50%		0	0	0	0	1,047	1,967	1,772	1,772	1,772	1,771	1,771	1,771	13,643
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.010800		0	0	0	0	905	850	765	765	765	765	765	765	6,345
e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			0	0	0	0	6,543	11,713	10,709	10,263	10,247	10,228	10,212	10,195	80,110
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			0	0	0	0	6,543	11,713	10,709	10,263	10,247	10,228	10,212	10,195	80,110

For Project: CAIR Crystal River AFUDC - CR4 Sootblower & Intelligent Soot Blowing Controls (Project 7.4h)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1 Investments															
a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$868,428	$32,627	$10,518	$894	$5,074	$450	$917,991
b. Clearings to Plant			0	0	0	0	0	0	868,428	32,627	10,518	894	5,074	450	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		$0	0	0	0	0	0	0	868,428	901,055	911,572	912,467	917,541	917,991	
3 Less: Accumulated Depreciation		0	0	0	0	0	0	0	(905)	(2,782)	(4,681)	(6,582)	(8,494)	(10,406)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$0	0	0	0	0	0	0	867,523	898,273	906,892	905,885	909,047	907,585	
6 Average Net Investment			0	0	0	0	0	0	433,762	882,898	902,583	906,389	907,466	908,316	
7 Return on Average Net Investment															
a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		0	0	0	0	0	0	1,067	2,172	2,221	2,230	2,233	2,235	$12,158
b. Equity Component Grossed Up For Taxes	8.02%		0	0	0	0	0	0	2,900	5,903	6,035	6,060	6,067	6,073	33,038
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	2.50%		0	0	0	0	0	0	905	1,877	1,899	1,901	1,912	1,912	10,406
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.010800		0	0	0	0	0	0	782	811	820	821	826	826	4,886
e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			0	0	0	0	0	0	5,654	10,763	10,975	11,012	11,038	11,046	60,488
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			0	0	0	0	0	0	5,654	10,763	10,975	11,012	11,038	11,046	60,488

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2010 through December 2010
CAIR/CAMR Crystal River AFUDC (Project 7.4 Recap)

For Project: CAIR Crystal River AFUDC - CR4 SCR (Project 7.4I)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$96,108,513	$1,742,681	$2,420,271	$1,372,492	$7,803,944	$528,725	$342,057	($851,115)	$109,467,569
	b. Clearings to Plant			0	0	0	0	96,108,513	1,742,681	2,420,271	1,372,492	7,803,944	528,725	342,057	(851,115)	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$0	0	0	0	0	96,108,513	97,851,195	100,271,465	101,643,957	109,447,902	109,976,627	110,318,684	109,467,569	
3	Less: Accumulated Depreciation		0	0	0	0	0	(100,113)	(303,970)	(512,869)	(724,627)	(952,643)	(1,181,761)	(1,411,592)	(1,639,649)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$0	0	0	0	0	96,008,400	97,547,225	99,758,596	100,919,330	108,495,259	108,794,866	108,907,092	107,827,920	
6	Average Net Investment			0	0	0	0	48,004,200	96,777,812	98,652,911	100,338,963	104,707,295	108,645,062	108,850,979	108,367,506	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		0	0	0	0	118,105	238,104	242,717	246,865	257,613	267,301	267,807	266,618	$1,905,130
	b. Equity Component Grossed Up For Taxes	8.02%		0	0	0	0	320,965	647,074	659,611	670,884	700,092	726,421	727,797	724,565	5,177,409
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		0	0	0	0	100,113	203,857	208,899	211,758	228,016	229,118	229,831	228,057	1,639,649
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010800		0	0	0	0	86,498	88,066	90,244	91,480	98,503	98,979	99,287	98,521	751,578
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			0	0	0	0	625,681	1,177,101	1,201,471	1,220,987	1,284,224	1,321,819	1,324,722	1,317,761	9,473,766
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			0	0	0	0	625,681	1,177,101	1,201,471	1,220,987	1,284,224	1,321,819	1,324,722	1,317,761	9,473,766

For Project: CAIR Crystal River AFUDC - CR4 FGD (Project 7.4J)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$123,632,639	$2,006,774	$1,061,537	$5,005,745	$9,179,682	$317,857	$134,282	($1,283,872)	$140,054,642
	b. Clearings to Plant			0	0	0	0	123,632,639	2,006,774	1,061,537	5,005,745	9,179,682	317,857	134,282	(1,283,872)	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$0	0	0	0	0	123,632,639	125,639,412	126,700,949	131,706,694	140,886,376	141,204,232	141,338,514	140,054,642	
3	Less: Accumulated Depreciation		0	0	0	0	0	(128,784)	(390,533)	(654,493)	(928,882)	(1,222,395)	(1,516,570)	(1,811,025)	(2,102,806)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$0	0	0	0	0	123,503,855	125,248,879	126,046,456	130,777,812	139,663,981	139,687,662	139,527,489	137,951,836	
6	Average Net Investment			0	0	0	0	61,751,927	124,376,367	125,647,668	128,412,134	135,220,896	139,675,821	139,607,576	138,739,663	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		0	0	0	0	151,929	306,005	309,133	315,934	332,686	343,646	343,478	341,343	$2,444,154
	b. Equity Component Grossed Up For Taxes	8.02%		0	0	0	0	412,885	831,603	840,103	858,587	904,111	933,898	933,442	927,639	6,642,268
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		0	0	0	0	128,784	261,749	263,960	274,389	293,513	294,175	294,455	291,781	2,102,806
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010800		0	0	0	0	111,269	113,075	114,031	118,536	126,798	127,084	127,205	126,049	964,047
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			0	0	0	0	804,867	1,512,432	1,527,227	1,567,446	1,657,108	1,698,803	1,698,580	1,686,812	12,153,275
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			0	0	0	0	804,867	1,512,432	1,527,227	1,567,446	1,657,108	1,698,803	1,698,580	1,686,812	12,153,275

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2010 through December 2010
CAIR/CAMR Crystal River AFUDC (Project 7.4 Recap)

For Project: CAIR Crystal River AFUDC - Gypsum Handling (Project 7.4k)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			($566,415)	($483)	$140	$18	$0	$0	$0	$0	$0	$0	$0	$0	($566,741)
	b. Clearings to Plant			(566,415)	(483)	140	18	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$21,555,142	20,988,727	20,988,244	20,988,384	20,988,402	20,988,402	20,988,402	20,988,402	20,988,402	20,988,402	20,988,402	20,988,402	20,988,402	
3	Less: Accumulated Depreciation		(26,417)	(69,144)	(112,870)	(156,596)	(200,322)	(244,048)	(287,774)	(331,500)	(375,226)	(418,952)	(462,678)	(506,404)	(550,130)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		21,528,725	20,919,583	20,875,374	20,831,788	20,788,060	20,744,354	20,700,628	20,656,902	20,613,176	20,569,450	20,525,724	20,481,998	20,438,272	
6	Average Net Investment			21,224,654	20,897,479	20,853,581	20,809,934	20,766,217	20,722,491	20,678,765	20,636,039	20,591,313	20,547,587	20,503,861	20,460,135	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		52,219	51,414	51,306	51,199	51,091	50,984	50,876	50,769	50,661	50,553	50,446	50,338	$611,856
	b. Equity Component Grossed Up For Taxes	8.82%		141,912	139,724	139,431	139,139	138,847	138,554	138,262	137,970	137,677	137,385	137,093	136,800	1,662,794
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		43,727	43,726	43,726	43,726	43,726	43,726	43,726	43,726	43,726	43,726	43,726	43,726	524,713
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010800		18,890	18,889	18,890	18,890	18,890	18,890	18,890	18,890	18,890	18,890	18,890	18,890	226,679
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			256,748	253,753	253,353	252,954	252,554	252,154	251,754	251,355	250,954	250,554	250,155	249,754	3,026,042
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			256,748	253,753	253,353	252,954	252,554	252,154	251,754	251,355	250,954	250,554	250,155	249,754	3,026,042

For Project: CAIR Crystal River AFUDC - CR5 Acid Mist Mitigation Controls (Project 7.4l)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$9,356,547	$50,156	$0	$0	$0	$0	$0	$0	$9,406,704
	b. Clearings to Plant			0	0	0	0	9,356,547	50,156	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$0	0	0	0	0	9,356,547	9,406,704	9,406,704	9,406,704	9,406,704	9,406,704	9,406,704	9,406,704	
3	Less: Accumulated Depreciation		0	0	0	0	0	(9,747)	(29,344)	(48,941)	(68,538)	(88,135)	(107,732)	(127,329)	(146,926)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$0	0	0	0	0	9,346,801	9,377,360	9,357,763	9,338,166	9,318,569	9,298,972	9,279,375	9,259,778	
6	Average Net Investment			0	0	0	0	4,673,400	9,362,080	9,367,562	9,347,965	9,328,368	9,308,771	9,289,174	9,269,577	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		0	0	0	0	11,498	23,034	23,047	22,999	22,951	22,902	22,854	22,806	$172,091
	b. Equity Component Grossed Up For Taxes	8.02%		0	0	0	0	31,247	62,597	62,633	62,502	62,371	62,240	62,109	61,978	467,677
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		0	0	0	0	9,747	19,597	19,597	19,597	19,597	19,597	19,597	19,597	146,926
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010800		0	0	0	0	8,421	8,466	8,466	8,466	8,466	8,466	8,466	8,466	67,683
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			0	0	0	0	60,913	113,694	113,743	113,564	113,385	113,205	113,026	112,847	854,377
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			0	0	0	0	60,913	113,694	113,743	113,564	113,385	113,205	113,026	112,847	854,377

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - January 2010 through December 2010
CAIR/CAMR Crystal River AFUDC (Project 7.4 Recap)

For Project: CAIR Crystal River AFUDC - FGD Settling Pond (Project 7.4m)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1 Investments															
a. Expenditures/Additions			$0	$5,902,274	($145,728)	($823,951)	($179,522)	($94,910)	$1,802,912	$1,220,226	$578,296	($591,775)	$9,443	$0	$7,677,264
b. Clearings to Plant			0	5,902,274	(145,728)	(823,951)	(179,522)	(94,910)	1,802,912	1,220,226	578,296	(591,775)	9,443	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		$0	0	5,902,274	5,756,546	4,932,594	4,753,073	4,658,163	6,461,074	7,681,300	8,259,596	7,667,821	7,677,264	7,677,264	
3 Less: Accumulated Depreciation		0	0	(3,689)	(10,885)	(17,051)	(22,992)	(28,815)	(36,891)	(46,493)	(56,817)	(66,402)	(75,999)	(85,596)	
4 CWIP - Non-Interest Bearing		0	0	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5 Net Investment (Lines 2 + 3 + 4)		0	0	5,898,585	5,745,660	4,915,543	4,730,080	4,629,347	6,424,183	7,634,807	8,202,778	7,601,418	7,601,265	7,591,668	
6 Average Net Investment			0	2,949,292	5,822,122	5,330,602	4,822,812	4,679,714	5,526,765	7,029,495	7,918,793	7,902,098	7,601,341	7,596,466	
7 Return on Average Net Investment															
a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		0	7,256	14,324	13,115	11,866	11,514	13,598	17,295	19,483	19,442	18,702	18,690	$165,285
b. Equity Component Grossed Up For Taxes	8.02%		0	19,720	38,928	35,641	32,246	31,289	36,953	47,000	52,946	52,835	50,824	50,791	449,173
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	1.50%		0	3,689	7,196	6,166	5,941	5,823	8,076	9,602	10,324	9,585	9,597	9,597	85,596
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.010800		0	5,312	5,181	4,439	4,278	4,192	5,815	6,913	7,434	6,901	6,910	6,910	64,285
e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			0	35,977	65,629	59,361	54,331	52,818	64,442	80,810	90,187	88,763	86,033	85,988	764,339
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			0	35,977	65,629	59,361	54,331	52,818	64,442	80,810	90,187	88,763	86,033	85,988	764,339

For Project: CAIR Crystal River AFUDC - Coal Pile Runoff Treatment System (Project 7.4n)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1 Investments															
a. Expenditures/Additions			$0	$15,906,132	$49,595	$0	$0	$13,377	$0	$0	$0	$0	$0	$0	$15,969,105
b. Clearings to Plant			0	15,906,132	49,595	0	0	13,377	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		$0	0	15,906,132	15,955,728	15,955,728	15,955,728	15,969,105	15,969,105	15,969,105	15,969,105	15,969,105	15,969,105	15,969,105	
3 Less: Accumulated Depreciation		0	0	(9,942)	(29,887)	(49,832)	(69,777)	(89,738)	(109,699)	(129,660)	(149,621)	(169,582)	(189,543)	(209,504)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$0	0	15,896,191	15,925,841	15,905,896	15,885,951	15,879,367	15,859,406	15,839,445	15,819,484	15,799,523	15,779,562	15,759,601	
6 Average Net Investment			0	7,948,095	15,911,016	15,915,869	15,895,924	15,882,659	15,869,387	15,849,426	15,829,465	15,809,504	15,789,543	15,769,582	
7 Return on Average Net Investment															
a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		0	19,555	39,146	39,158	39,109	39,076	39,044	38,995	38,945	38,896	38,847	38,798	$409,569
b. Equity Component Grossed Up For Taxes	8.02%		0	53,142	106,384	106,416	106,283	106,194	106,106	105,972	105,839	105,705	105,572	105,438	1,113,051
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	1.50%		0	9,942	19,945	19,945	19,945	19,961	19,961	19,961	19,961	19,961	19,961	19,961	209,504
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.010800		0	14,316	14,360	14,360	14,360	14,372	14,372	14,372	14,372	14,372	14,372	14,372	158,000
e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			0	96,955	179,835	179,879	179,697	179,603	179,483	179,300	179,117	178,934	178,752	178,569	1,890,124
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			0	96,955	179,835	179,879	179,697	179,603	179,483	179,300	179,117	178,934	178,752	178,569	1,890,124

For Project: CAIR Crystal River AFUDC - Dibasic Acid Additive System (Project 7.4o)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1 Investments															
a. Expenditures/Additions			$0	$0	$0	$310,322	$0	$341	$968	$0	$0	$0	$772,016	$10,771	$1,094,417
b. Clearings to Plant			0	0	0	310,322	0	341	968	0	0	0	772,016	10,771	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		$0	0	0	0	310,322	310,322	310,663	311,631	311,631	311,631	311,631	1,083,647	1,094,417	
3 Less: Accumulated Depreciation		0	0	0	0	(324)	(971)	(1,618)	(2,267)	(2,916)	(3,565)	(4,214)	(6,472)	(8,752)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		$0	0	0	0	309,999	309,352	309,045	309,364	308,715	308,066	307,417	1,077,175	1,085,666	
6 Average Net Investment			0	0	0	154,999	309,675	309,199	309,205	309,040	308,391	307,742	692,296	1,081,420	
7 Return on Average Net Investment															
a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		0	0	0	381	762	761	761	760	759	757	1,703	2,661	$9,305
b. Equity Component Grossed Up For Taxes	8.02%		0	0	0	1,036	2,071	2,067	2,067	2,066	2,062	2,058	4,629	7,231	25,287
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	2.50%		0	0	0	324	647	647	649	649	649	649	2,258	2,280	8,752
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.010800		0	0	0	279	279	280	280	280	280	280	975	985	3,918
e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			0	0	0	2,020	3,759	3,755	3,757	3,756	3,750	3,744	9,565	13,157	47,262
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			0	0	0	2,020	3,759	3,755	3,757	3,756	3,750	3,744	9,565	13,157	47,262

For Project: CAIR Crystal River AFUDC - Bottom Ash (PH) (Project 7.4p)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1 Investments															
a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$39,471	$39,471
b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		$0	0	0	0	0	0	0	0	0	0	0	0	0	
3 Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	39,471	
5 Net Investment (Lines 2 + 3 + 4)		$0	0	0	0	0	0	0	0	0	0	0	0	39,471	
6 Average Net Investment			0	0	0	0	0	0	0	0	0	0	0	19,736	
7 Return on Average Net Investment															
a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		0	0	0	0	0	0	0	0	0	0	0	49	$49
b. Equity Component Grossed Up For Taxes	8.02%		0	0	0	0	0	0	0	0	0	0	0	132	132
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	2.10%		0	0	0	0	0	0	0	0	0	0	0	0	0
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.010800		0	0	0	0	0	0	0	0	0	0	0	0	0
e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			0	0	0	0	0	0	0	0	0	0	0	181	181
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	181	181

For Project: Crystal River Thermal Discharge Compliance Project AFUDC - Point of Discharge (POD) Cooling Tower (Project 11.1a)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$0	0	0	0	0	0	0	0	0	0	0	0	0	
6	Average Net Investment			0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		0	0	0	0	0	0	0	0	0	0	0	0	$0
	b. Equity Component Grossed Up For Taxes	8.82%		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010940		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0

For Project: Crystal River Thermal Discharge Compliance Project AFUDC - MET Tower (Project 11.1b)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-10	Actual Feb-10	Actual Mar-10	Actual Apr-10	Actual May-10	Actual Jun-10	Actual Jul-10	Actual Aug-10	Actual Sep-10	Actual Oct-10	Actual Nov-10	Actual Dec-10	End of Period Total
1	Investments															
	a. Expenditures/Additions			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		$361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	
3	Less: Accumulated Depreciation		(2,434)	(2,946)	(3,458)	(3,970)	(4,482)	(4,994)	(5,506)	(6,018)	(6,530)	(7,042)	(7,554)	(8,066)	(8,578)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		$359,302	358,790	358,278	357,766	357,254	356,742	356,230	355,718	355,206	354,694	354,182	353,670	353,158	
6	Average Net Investment			359,046	358,534	358,022	357,510	356,998	356,486	355,974	355,462	354,950	354,438	353,926	353,414	
7	Return on Average Net Investment															
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		883	882	881	880	878	877	876	875	873	872	871	870	$10,518
	b. Equity Component Grossed Up For Taxes	8.82%		2,401	2,397	2,394	2,390	2,387	2,384	2,380	2,377	2,373	2,370	2,366	2,363	28,582
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.70%		512	512	512	512	512	512	512	512	512	512	512	512	6,144
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010940		330	330	330	330	330	330	330	330	330	330	330	330	3,960
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			4,126	4,121	4,117	4,112	4,107	4,103	4,098	4,094	4,088	4,084	4,079	4,075	49,204
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			4,126	4,121	4,117	4,112	4,107	4,103	4,098	4,094	4,088	4,084	4,079	4,075	49,204

Docket No. 110007-EI
Progress Energy Florida
Witness: Patricia Q. West
Exhibit No. __ (PQW-1)

Progress Energy Florida

Review of Integrated Clean Air Compliance Plan

Submitted to the Florida Public Service Commission

April 1, 2011

Progress Energy

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI EXHIBIT 18
PARTY PROGRESS ENERGY FLORIDA
DESCRIPTION PATRICIA Q. WEST (PQW-1)
DATE 11/01/11

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Executive Summary

In the 2007 Environmental Cost Recovery Clause (ECRC) Docket (No. 070007-EI) and as reaffirmed in the 2008, 2009 and 2010 ECRC Dockets (Nos. 080007-EI, 090007-EI and 100007-EI), the Public Service Commission approved Progress Energy Florida's (PEF's) updated Integrated Clean Air Compliance Plan (Plan D) as a reasonable and prudent means to comply with the requirements of the Clean Air Interstate Rule (CAIR), the Clean Air Mercury Rule (CAMR), the Clean Air Visibility Rule (CAVR), and related regulatory requirements. In its 2007 final order, the Commission also directed PEF to file as part of its ECRC true-up testimony "a yearly review of the efficacy of its Plan D and the cost-effectiveness of PEF's retrofit options for each generating unit in relation to expected changes in environmental regulations." This report provides the required review for 2011.

The primary original components of PEF's Compliance Plan "D" are summarized as follows:

Sulfur Dioxide (SO_2):

- Installation of wet scrubbers, flue gas desulfurization system (FGD) on Crystal River Units 4 and 5
- Fuel switching at Crystal River Units 1 and 2 to burn low sulfur coal
- Fuel switching at Anclote Units 1 and 2 to burn low sulfur oil
- Purchases of SO_2 allowances

Nitrogen Oxides (NOx):

- Installation of low NOx burners (LNBs) and selective catalytic reduction (SCR) on Crystal River Units 4 and 5
- Installation of LNBs and separated over-fire air (LNB/SOFA) or alternative NOx controls at Anclote Units 1 and 2
- Purchase of annual and ozone season NOx allowances

Mercury:

- Co-benefit of wet scrubbers and SCRs at Crystal River Units 4 and 5
- Installation of powdered activated carbon (PAC) injection on Crystal River Unit 2
- Purchase of mercury (Hg) allowances

As detailed in PEF's 2007 ECRC filing, PEF decided upon Plan D based on a quantitative and qualitative evaluation of the ability of alternative plans to meet environmental requirements, while managing risks and controlling costs. That evaluation demonstrated that Plan D is PEF's most cost-effective alternative to meet the applicable regulatory requirements. The Plan is expected to meet environmental requirements by striking a balance between reducing emissions, primarily through the installation of controls on PEF's largest and newest coal units (Crystal River Units 4 and 5), and making strategic use of emission allowance markets.

In accordance with the Commission's final order in the 2007 ECRC docket, PEF has reviewed the efficacy of Plan D and the cost-effectiveness of retrofit options in relation to expected changes in environmental regulations. With regard to Plan D's efficacy, PEF remains confident that Plan D will have the desired effect of achieving timely compliance with the applicable regulations in a cost-effective manner. PEF has achieved several project milestones, including:

- Crystal River Unit 5 SCR in service in June 2009;
- Completion of the SCR Common project in July 2009;
- Crystal River Unit 5 FGD in service in December 2009;
- Crystal River FGD Common in service in December 2009; and
- Crystal River Unit 4 SCR/FGD in service in May 2010;

All of the Crystal River Unit 4 & 5 projects are now in-service and the targeted environmental benefits have been met or exceeded. The Unit 4 & 5 SCRs reduce NO_x emissions by approximately 90%. The Unit 4 & 5 FGDs remove 97% of the Sulfur Dioxide (SO_2).

No new or revised environmental regulations have been adopted that have a direct bearing on PEF's compliance plan. In 2008, the Florida Legislature adopted legislation authorizing the Florida Department of Environmental Protection (FDEP) to adopt rules establishing a cap-and-trade program to regulate emissions of greenhouse gases, such as carbon dioxide (CO_2). To date, FDEP has not adopted any cap-and-trade rules and, under the legislation, any such rules must be ratified by the Legislature.

There currently are no demonstrated retrofit options to reduce CO_2 emissions from fossil fuel-fired electric generating units such as Crystal River Units 4 and 5, which are the primary focus of PEF's compliance plan. Likewise, replacement of coal-fired generation from Crystal River Units 4 and 5 with natural-gas fired generation is not a viable option because it cannot be implemented in time to meet the CAIR compliance deadlines. PEF continues to carefully evaluate future compliance options in light of EPA's ongoing development of Maximum Achievable Control Technology (MACT) standards for coal and oil-fired electric generating units. EPA released its proposed MACT rule on March 16, 2011 and PEF is actively assessing the rule.

I. Introduction

In its Final Order in the 2007 ECRC Docket (No. 070007-EI) and as reaffirmed in the 2008, 2009 and 2010 ECRC Dockets (Nos. 080007-EI, 090007-EI and 100007-EI), the Public Service Commission approved PEF's updated Integrated Clean Air Compliance Plan (Plan D) as a reasonable and prudent means to comply with the requirements of CAIR, CAMR, CAVR and related regulatory requirements. *In re Environmental Cost Recovery Clause*, Order No. PSC-07-0922-FOF-EI, p. 8 (Nov. 16, 2007), the Commission specifically found that "PEF's updated Integrated Clean Air Compliance Plan represents the most cost-effective alternative for achieving and maintaining compliance with CAIR, CAMR, and CAVR, and related regulatory requirements, and it is reasonable and prudent for PEF to recover prudently incurred costs to implement the plan." *Id.* In its final order, the Commission also directed PEF to file as part of its ECRC true-up testimony "a yearly review of the efficacy of its Plan D and the cost-effectiveness of PEF's retrofit options for each generating unit in relation to expected changes in environmental regulations." *Id.* The purpose of this report is to provide the required review for 2010 activities.

II. PEF's Integrated Clean Air Compliance Plan

A. Background

The CAIR and CAVR programs require PEF and other utilities to significantly reduce emissions of sulfur dioxide (SO_2) and nitrogen oxides (NOx). Under CAIR, these reductions must be met in incremental phases. Phase I began in 2009 for NOx and in 2010 for SO_2. Phase II begins in 2015 for both NOx and SO_2.

In March 2006, PEF submitted a report and supporting testimony presenting its integrated plan for complying with the new rules, as well as the process PEF utilized in evaluating alternative plans, to the Commission. The analysis included an examination of the projected emissions associated with several alternative plans and a comparison of economic impacts, in terms of cumulative present value of revenue requirements. PEF's Integrated Clean Air Compliance Plan, designated in the report as Plan D, was found to be the most cost-effective compliance plan for CAIR, CAMR, and CAVR from among five alternative plans.

In June 2007, PEF submitted an updated report and supporting testimony summarizing the status of the Plan and an updated economic analysis incorporating certain plan revisions necessitated by changed circumstances. Consistent with the approach utilized in 2006, PEF performed a quantitative evaluation to compare the ability of the modified alternative plans to meet environmental requirements, while managing risks and controlling costs. That evaluation demonstrated that Plan D, as revised, is PEF's most cost-effective alternative to meet the applicable regulatory requirements. Based on that analysis, the Commission approved PEF's Plan D as reasonable and prudent, and held that PEF should recover the prudently incurred costs of implementing the plan. Most recently, in 2010, the Commission approved PEF's annual Review of Integrated Clean Air Compliance Plan. Order No. PSC-10-0683-FOF-EI.

B. PEF's Plan "D"

PEF's compliance plan (Plan D) meets the applicable environmental requirements by striking a good balance between reducing emissions, primarily through installation of controls on PEF's largest and newest coal units (Crystal River Units 4 and 5), and making strategic use of the allowance markets to comply with CAIR requirements. Specific components of the Plan are summarized below.

1. CAIR SO_2 Plan

The most significant component of PEF's Integrated Clean Air Compliance Plan is the installation of flue gas desulfurization (FGD) systems, also known as wet scrubbers, on Crystal River Units 4 and 5 to comply with CAIR's SO_2 requirements. PEF also plans to purchase limited SO_2 allowances. The plan also included switching Crystal River Units 1 and 2 to burn low-sulfur (1.2 lbs SO_2/mmBtu) "compliance" coal, and burning low sulfur oil at Anclote Units 1 and 2. However, these components of the plan are no longer expected to be necessary in order to achieve the lowest overall cost when the cost of allowances and other relevant fuel selections are considered.

2. CAIR NOx Plan

The primary component of PEF's NOx compliance plan is the installation of LNBs and SCR systems on Crystal River Units 4 and 5. To achieve compliance with CAIR, PEF has taken strategic advantage of CAIR's cap-and-trade feature by purchasing some annual and ozone season NOx allowances.

3. Mercury Plan

As discussed more fully below, a federal appeals court vacated the Federal CAMR regulations in 2008. With CAMR vacated, PEF is not required at this time to install mercury controls to meet the CAMR emission limits. This development does not have any immediate, significant impact on PEF's implementation of Plan D because installation of NOx and SO_2 controls on Crystal River Units 4 and 5 is expected to reduce mercury emissions by at least 80% and the plan did not contemplate installation of any mercury-specific controls until 2017. PEF will continue to monitor the regulatory developments related to utility mercury emissions, as well as research and development of mercury control technologies to ensure that the most reliable and cost-effective control technology is used when required.

4. CAVR Visibility Plan

PEF operates four units that are potentially subject to Best Available Retrofit Technology (BART) under CAVR, including Anclote Units 1 and 2 and Crystal River Units 1 and 2. As indicated above, PEF's Compliance Plan included switching to low-sulfur oil and the installation of LNBs at Anclote Units 1 and 2 or other alternative NOx controls such as selective non-catalytic reduction, fuel oil additives, combustion control technologies, and burner tip modifications. Because the results of the modeling for Crystal River Units 1 and 2 showed visibility impacts at or above regulatory threshold levels, PEF applied for a BART permit for those units. This permit was issued on February 26, 2009 and it establishes a combined BART emission standard for Crystal River Units 1 and 2. By establishing a combined emission standard, the permit provides PEF additional flexibility in determining the most cost-effective compliance option. The modeling of air emissions from Anclote Units 1 and 2 supported FDEP's exempting these units from CAVR. PEF is continuing to evaluate potential options in light of EPA's ongoing development of MACT standards for electric generating units (discussed below).

III. Efficacy of PEF's Plan D

As noted above, in its Final Order in Docket No. 070007- EI, the Commission requested a review of the efficacy of PEF's Integrated Clean Air Compliance Plan (Plan D) and the cost-effectiveness of PEF's retrofit options for each generating unit in relation to expected changes in environmental regulations. With regard to Plan D's efficacy, PEF remains confident that Plan D will have the desired effect of achieving timely compliance with the applicable regulations in a cost-effective manner. As noted below, however, there are uncertainties that could affect the timing and costs of implementation.

A. Project Milestones

PEF completed installation of Plan D's controls on Crystal River Units 4 and 5 as contemplated in PEF's 2010 ECRC filing. Since the submittal of last year's annual review, PEF has achieved the following project milestones:

ACHIEVED CAIR COMPLIANCE MILESTONES

Coal Pile Runoff Treatment System in service	Feb 10
FGD Settling Ponds in service	Feb 10
Chimney installation complete	Mar10
Unit 4 Absorber complete	Mar 10
Dibasic Acid System in service	Apr 10
Unit 4 SCR Duct work Tie-in complete	May 10
Unit 4 FGD Duct work Tie-in complete	May 10
Unit 4 SCR mechanical completion	May 10
Unit 4 FGD mechanical completion	May 10
Acid Mist Mitigation System in service	May 10
Crystal River Unit 4 SCR in service	May 10
Crystal River Unit 4 FGD in service	May 10

B. Projects Costs

During 2010, PEF incurred approximately $62 million in capital costs for the Crystal River projects. The 2010 figure includes approximately $47 million in contract billings, $9 million of owner's costs, and $6 million of AFUDC. As of December 2010, the life-to-date capital costs were approximately $1,243 million. This figure includes approximately $1,073 million in contract billings, $43 million of owner's costs, and $127 million of AFUDC. The contract billings include payments for: major construction work, design and engineering work, procurement of major equipment, and environmental permits. The overall budget, excluding AFUDC, is $1.13 billion. Currently, costs are on track to be completed within the overall budget.

C. Uncertainties

PEF successfully completed installation of controls on Crystal River Units 4 and 5. The project is now in the close-out phase which includes, among other things, completing the punch-list, demobilization and site restoration. The primary risk remaining on the PEF CAIR compliance projects is associated with the timing of project close-out activities while the plant is operating; however, emergent risks could still occur. Project contingency has been developed to cover these unknowns, and PEF employees are actively engaged to minimize or avoid any project schedule impacts.

IV. Retrofit Options in Relation to Expected Changes in Environmental Regulations

Since PEF's filing in the 2009 ECRC docket, no new or revised environmental regulations have been adopted that have a direct bearing on Plan D. The following discussion addresses three regulatory developments that have been the topic of discussion since PEF's 2009 filing.

A. Status of CAIR

In July 2008, the U.S. Circuit Court of Appeals for the District of Columbia issued a decision vacating CAIR in its entirety. *North Carolina v. EPA*, 531 F.3d 896 (D.C. Cir. 2008). However, in response to EPA's petition for rehearing, the court requested briefs from the parties regarding whether CAIR should be remanded to EPA without vacatur of CAIR. On December 23, the Court decided to remand CAIR without vacatur, thereby leaving the rule and its compliance obligations in place until EPA revises or replaces the CAIR. *North Carolina v. EPA*, 550 F.3d 1176 (D.C. Cir. 2008). Thus, PEF must continue to move forward with its Integrated

Clean Air Compliance Plan in order to meet the impending CAIR compliance deadlines. In July 2010, EPA proposed the Transport Rule, which would replace CAIR with a new, limited cap-and-trade program for SO_2 and NO_x. A final Transport Rule is expected in the summer of 2011. The rule is expected to be at least as stringent as the CAIR; therefore, PEF'sIntegrated Clean Air Compliance Plan will continue to be necessary.

B. Vacatur of CAMR & Development of MACT Standards

In February 2008, the U.S. Court of Appeals for the District of Columbia (D.C.) Circuit vacated the Federal CAMR regulations. *See*, *New Jersey v. EPA*, 517 F. 3d 574 (D.C. Cir. 2008). EPA originally promulgated CAMR under Section 111 of the Clean Air Act (CAA), rather than CAA Section 112, which requires EPA to establish MACT standards for hazardous air pollutants. In light of the vacatur of CAMR, EPA has announced its intention to proceed with rulemaking to establish MACT standards for certain coal and oil-fired electric generating units, including Crystal River Units 1, 2, 4 and 5; Anclote Units 1 and 2; and Suwannee Steam Units 1, 2, and 3. As required by Consent Decree, EPA promulgated a proposed electric generating unit (EGU) MACT on March 16, 2011, and a final rule must be in place no later than November 16, 2011. *See* 74 *Fed. Reg.* 55547 (Oct. 28, 2009). To that end, in 2010 the EPA issued an Information Collection Request (ICR) to PEF and other utilities in order to collect data for use in the development of the EGU MACT. At this time, it is impossible to predict what the final EGU MACT standards will be. However, in light of EPA's aggressive rulemaking schedule, PEF is carefully evaluating potential compliance options based on several possible regulatory scenarios.

C. Greenhouse Gas Regulation

When PEF committed to placing environmental controls on Crystal River Units 4 and 5, climate change issues were only beginning to be discussed. At that time, PEF had to commit to installing controls in order to meet the fast approaching 2009 and 2010 CAIR compliance deadlines. Governor Crist subsequently issued Executive Order 07-127 directing FDEP to promulgate regulations requiring reductions in utility carbon dioxide (CO_2) emissions. In addition, the 2008 Florida Legislature enacted legislation authorizing FDEP to adopt rules establishing a cap-and-trade program and requiring FDEP to submit any such rules for legislative review and ratification. To date, FDEP has not adopted any cap-and-trade rules. A number of bills that would regulate greenhouse gas (GHG) emissions have been introduced to Congress over the past several years, but to date none have passed both houses. In the meantime, EPA has begun implementation of a regulatory approach to reducing GHG emissions through the Clean Air Act. However, at this time, there are still no retrofit options commercially available to reduce CO_2 emissions from fossil fuel-fired electric generating units such as Crystal River Units 4 and 5, which are the primary focus of PEF's compliance plan. To date, there have been no large-scale commercial carbon capture and sequestration technology demonstrations on electric utility units. Until numerous technological, regulatory and liability issues are resolved, it will be impossible to determine whether carbon capture and storage would be a technically feasible or cost-effective means of complying with a CO_2 regulatory regime. Likewise, replacing coal-fired generation from Crystal River Units 4 and 5 with lower CO_2-emitting natural gas-fired combined cycle generation[1] is not a viable option at this late date. As of May 2010, PEF has placed in service all of the Plan D major components.

V. Conclusion

Based on project milestones achieved to date, PEF remains confident that Plan D will have the desired effect of achieving timely compliance with the applicable regulations in a cost-effective manner. No new or revised environmental regulations have been adopted that have a direct bearing on PEF's compliance plan. Although FDEP is in the process of developing a cap-and-trade program to regulate CO_2 emissions, no regulations have been adopted to date and there currently are no demonstrated retrofit options to reduce CO_2 emissions from fossil fuel-fired electric generating units. For these reasons, PEF's Plan D continues to represent the most cost-effective alternative for achieving and maintaining compliance with the applicable regulatory requirements. PEF will continue to evaluate future compliance options in light of EPA's ongoing development of MACT standards for coal and oil-fired generating units.

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[1] The CO_2 emission rate for natural gas-fired combined cycle (NG/CC) units is approximately 50% of the emission rate for coal-fired generating units. Thus, replacing coal-fired generation with NG/CC would not eliminate costs associated with any to-be-adopted CO_2 regulatory regime.

BEFORE THE PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause	DOCKET NO. 110007-EI FILED: MARCH 11, 2011

PETITION OF PROGRESS ENERGY FLORIDA, INC. FOR APPROVAL OF COST RECOVERY FOR NEW ENVIRONMENTAL PROGRAM

Progress Energy Florida, Inc. ("PEF" or "Company"), pursuant to Section 366.8255, Florida Statutes, and Florida Public Service Commission ("Commission") Order Nos. PSC-94-0044-FOF-EI and PSC-99-2513-FOF-EI, hereby petitions the Commission for approval for recovery through the Environmental Cost Recovery Clause ("ECRC") of costs associated with new conditions in the Florida Department of Environmental Protection's ("FDEP's") renewals of National Pollutant Discharge Elimination System ("NPDES) permits for PEF's Anclote, Bartow, Crystal River and Suwannee Plants. In support, PEF states:

Introduction

1. Petitioner. PEF is a public utility subject to the regulatory jurisdiction of the Commission under Chapter 366, Florida Statutes. The Company's principal offices are located at 299 First Avenue North, St. Petersburg, Florida.

2. Service. All notices, pleadings and other communications required to be served on the petitioner should be directed to:

Gary V. Perko
Hopping Green & Sams, P.A.
119 S. Monroe St., Suite 300
P.O. Box 6526 (32314)
Tallahassee, FL 32301

John T. Burnett
Associate General Counsel
Progress Energy Services Co., LLC
299 First Avenue North, PEF-151
St. Petersburg, FL 33701

3. Cost Recovery Eligibility. PEF will incur costs to comply with new environmental requirements included in renewed NPDES permits issued or to be issued for PEF's Anclote, Bartow, Crystal River and Suwannee Plants. As detailed below, the compliance activities meet the criteria for cost recovery established by the Commission in Order No. PSC-94-0044-FOF-EI in that:

(a) all expenditures will be prudently incurred after April 13, 1993;

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

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

The information provided below for each program satisfies the minimum filing requirements established in Part VI of Order No. PSC-99-2513-FOF-EI.

4. Regulatory Requirements & Activities (All Plants). The Federal Clean Water Act requires all point source discharges to navigable waters from industrial facilities require permits under the NPDES program. See 33 U.S.C. § 1342. Pursuant to the U.S. Environmental Protection Agency's ("EPA's") approval, the Florida Department of Environmental Protection ("FDEP") implements the NPDES permitting program in Florida. Affected facilities are required to apply for renewed NPDES permits every five years. Several of PEF's facilities have either just completed or are about to complete the permit renewal process, which involves three steps: (i) issuance of a "Draft" Permit, (ii) followed by issuance of a "Proposed Permit," (iii) followed by issuance of a "Final Permit." At this point, the FDEP has issued a "Final Permit" and associated Administrative Order for PEF's Bartow Plant (Copy attached as Exhibit "A") and

a "Final Permit" for PEF's Anclote Plant (Copy provided as Exhibit "B"). PEF expects that permit renewal process for its Crystal River and Suwannee Plants will be completed sometime in calendar year 2011. Based on discussions with the FDEP, PEF understands that the following new requirements included in the Bartow and Anclote permits will also be included in the permits for Crystal River and Suwannee Plants:[1]

a. Thermal Studies: The thermal components of PEF's wastewater discharges are subject to state and federal water quality standards that prohibit "increase in the temperature of the RBW (receiving body of water) so as to cause substantial damage or harm to the aquatic life or vegetation therein or interfere with the beneficial uses assigned to the RBW." Rule 62-302.520(1)(a), F.A.C. Both the Bartow and Anclote Final Permits include a new condition requiring PEF to conduct a biological assessment of each plant's thermal plume to monitor compliance with the thermal water quality standard. Biological assessment activities will involve thermal plume delineations and mulit-year biological sampling and analysis in the area of the plant discharges. Site-specific monitoring plans of the study will be divided into two phases. Phase I involves monitoring and mapping the extent of the thermal plume for one year. Phase II involves the monitoring of various biological components (seagrass, fish/invertebrates, hard-bottom and soft-bottom sediment habitats) within the thermally impacted areas over 2 more years. See Exhibit "A", Final Permit, at p.17, Item VI.4 (Bartow); and Exhibit "B", Final Permit, at p.14, Item VI.4 (Anclote). The FDEP has

[1] In at least one prior case, the Commission approved recovery of costs for new requirements that a utility expected to be included in a pending NPDES renewal permit. See Order No. PSC-98-1764-FOF-EI, at p. 10, issued in Docket No. 980007-EI, In re: Environmental Cost Recovery Clause (Dec. 31, 1998). In that case, the Commission approved recovery subject to refund if the final permit did not include the expected new requirements. Id.

indicated that similar requirements will be included in the renewed permits for PEF's Crystal River and Suwannee plants.

b. Aquatic Organism Return Studies & Implementation: Section 316(b) of the Clean Water Act, 33 U.S.C. § 1326(b), requires implementation of best technology available (BTA) to protect aquatic organisms from, among other things, impingement of aquatic organisms associated with cooling water intake structures. In 2004, the EPA published its "Phase II" rules for the establishment of BTA for cooling water intake structures at existing power plants. On January 25, 2007, the U.S. Court of Appeals for the Second Circuit struck down several substantive portions of the Phase II rules. In response to the Court's decision, the EPA suspended the relevant parts of the Phase II rules and instructed State permitting authorities that they must establish permit conditions implementing Section 316(b) based on Best Professional Judgment (BPJ). See 72 Fed. Reg. 37107, 37108 (July 9, 2007). Pursuant to that directive, the FDEP included new conditions in both the Bartow and Anclote Final Permits requiring PEF to develop and implement a plan to minimize the impact of cooling tower intake impingement by helping return live fish, shellfish and other aquatic organisms collected on the intake screens to their natural habitat. The plan must be submitted within 12 months of final permit issuance and then implemented within 24 months after FDEP approval of the plan. Development of the plan will involve a biological and engineering evaluation. Implementation may involve significant capital improvements and modification of the cooling water intake structures. See Exhibit "A", Final Permit, at p.4, Condition I.A.10 and p. 17, Condition VI.3 (Bartow); and Exhibit "B", Final Permit, at p.8, Condition I.A.9 and p.14, Condition VI.3 (Anclote). The FDEP has indicated that similar requirements will be included in the renewed permits for PEF's Crystal River and Suwannee plants.

c. Whole Effluent Toxicity Testing: Since issuance of the prior round of PEF's NPDES permits, the FDEP adopted a new rule establishing limits for chronic whole effluent toxicity ("WET"). See Rule 62-4.241, F.A.C. In accordance with this new regulatory requirement, both the Bartow and Anclote Final Permits include a new condition requiring PEF to conduct quarterly chronic WET testing to evaluate the effects of each plant's effluent on certain aquatic organisms. The requirement to conduct chronic WET testing, which is more stringent than existing acute WET testing requirements, involves laboratory evaluation of the survival and growth of representative fish and shrimp species when exposed to effluent water samples for a determined period of time. See Exhibit "A", Final Permit, at pp. 5-7, Condition I.A.11 (Bartow); and Exhibit "B", Final Permit, at pp. 5-7, Condition I.A.5 (Anclote). The FDEP has indicated that similar requirements will be included in the renewed permits for PEF's Crystal River and Suwannee plants.

5. Additional Regulatory Requirements and Activities (Bartow Plant only): The Final Permit and an associated Administrative Order for PEF's Bartow Plant include the following additional new requirements for which PEF will incur environmental compliance costs:

a. Dissolved Oxygen Study: PEF is required to develop and implement a study of dissolved oxygen ("DO") levels in the Bartow Plant's discharge to ensure compliance with the water quality standard for dissolved oxygen. The study includes at least two years of DO monitoring during the warmer months and various report submittals. Monitoring will be conducted from boats as well as in situ automated monitoring probes. See Exhibit "A", Final Permit, at p.17, Condition VI.5.

b. Freeboard Limitation and Related Studies: The Final Permit for the Bartow Plant includes new limitations on the freeboard capacity of the facility's percolation basins. See Exhibit "A", Final Permit, at p.15, Condition IV.2. In conjunction with the Final Permit, the FDEP issued an Administrative Order that would provide a compliance schedule to allow the facility time to meet the new freeboard limitations. See Exhibit "A", Administrative Order. The Administrative Order requires PEF to conduct studies to evaluate whether the new freeboard limitations can be met under the existing design and to conduct additional feasibility studies if it is determined that the new limits cannot be met with the existing design . Id. at p.2.

6. No Base Rates Recovery of Program Costs. PEF seeks approval to recover through the ECRC incremental costs incurred to comply with the new requirements of the various NPDES renewal permits and related administrative order(s). None of the costs for which PEF seeks recovery were included in the MFRs that PEF filed in its last ratemaking proceeding in Docket No. 090079-EI. Therefore, the costs are not recovered in PEF's base rates.

7. Cost Estimates. PEF estimates that the total costs complying with the new NPDES permit requirements are approximately $1,110,000 for the remainder of 2011 and approximately $430,000 for the 2012. A cost breakdown for the various activities is provided in Confidential Exhibit "C."[2] Costs for the chronic WET testing will recur annually. Costs for

[2] As explained in the Request for Confidential Classification submitted contemporaneously with this Petition, projected costs for the specific activities are considered confidential pending completion of competitive bidding and contract negotiations with selected vendors.

implementing the various studies cannot be estimated at this time, but will be submitted for Commission review and approval at the appropriate time in future ECRC filings.

8. Prudence of Expenditures. In order to ensure that the costs incurred to comply with the new NPDES permit requirements are prudent and reasonable, PEF will identify qualified contractors and, when appropriate, will use competitive bidding.

9. No Change in Current ECRC Factors. PEF does not seek to change the ECRC factors currently in effect for 2011. The Company proposes to include in its estimated true-up filing for 2011 estimated program costs incurred subsequent to the filing of this petition through the end of 2011. The Company will include estimated program costs projected for 2012 and beyond in the appropriate projection filings. PEF expects that all of these costs will be subject to audit by the Commission and that the appropriate allocation of program costs will be addressed in connection with the annual ECRC filings.

10. No Material Facts in Dispute. PEF is not aware of any dispute regarding any of the material facts contained in this petition. The information provided in this petition demonstrates that the programs for which approval is requested meets the requirements of Section 366.8255 and applicable Commission orders for recovery through the ECRC.

WHEREFORE, Progress Energy Florida, Inc., requests that the Commission approve for recovery through the ECRC all costs reasonably and prudently incurred after the date of this petition in connection with the new NPDES permit requirements described more fully above.

RESPECTFULLY SUBMITTED this 11th day of March, 2011.

John T. Burnett
Associate General Counsel
PROGRESS ENERGY SERVICE
COMPANY, LLC
Post Office Box 14042, PEF-151
St. Petersburg, FL 33733-4042

HOPPING GREEN & SAMS, P.A.

By: Gary V. Perko
119 S. Monroe St., Ste. 300 (32301)
P.O. Box 6526
Tallahassee, FL 32314
gperko@hgslaw.com
Tel.: (850) 425-2359
Fax: (850) 224-8551

Attorneys for PROGRESS ENERGY FLORIDA, INC.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF PINELLAS)

The undersigned Patricia Q. West, first being duly sworn, deposes and says:

1. I am employed as Manager of Environmental Services / Power Generation Florida for Progress Energy Florida, Inc.

2. I have reviewed the above Petition of Progress Energy Florida, Inc. for Approval of Cost Recovery for New Environmental Program and the facts stated in that petition are true and correct to the best of my knowledge, information and belief.

Patricia Q. West
Patricia Q. West

Sworn to and subscribed before me by Patricia Q. West, who:

(✓) is personally known to me

( ) presented Florida Drivers License Number __________ as identification

this 8th day of March 2011.

JUNE C. MOONEY
MY COMMISSION # DD606913
EXPIRES: September 18, 2012
1-800-3-NOTARY Fl. Notary Discount Assoc. Co.

June C. Mooney
Notary Public

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via hand-delivery (*) or regular U.S. mail this 11th day of March, 2011.

Martha Carter Brown (*)
Office of General Counsel
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850
mbrown@psc.state.fl.us

John T. Butler, Esq.
Florida Power & Light Co.
700 Universe Blvd.
Juno Beach, FL 33408-0420
john.butler@fpl.com

Mr. Wade Litchfield
Florida Power & Light Co.
215 S. Monroe Street, Suite 810
Tallahassee, FL 32301
wade.litchfield@fpl.com

James D. Beasley, Esq.
Ausley & McMullen
P.O. Box 391
Tallahassee, FL 32302
jbeasley@ausley.com

John W. McWhirter, Jr.
McWhirter Reeves & Davidson, P.A.
P.O. Box 3350
Tampa, FL 33601-3350
jmcwhirter@mac-law.com

Jeffrey A. Stone, Esq.
Russell A. Badders, Esq.
Beggs & Lane Law Firm
P.O. Box 12950
Pensacola, FL 32591-2950
jas@beggslane.com
rab@beggslane.com

Susan Ritenour
Gulf Power Company
One Energy Place
Pensacola, FL 32520-0780
sdriteno@southernco.com

Capt. Shayla McNeill, USAF
Federal Executive Agencies
c/o AFLSA / JACL-ULT
139 Barnes Drive, Suite 1
Tyndall AFB, FL 32403
Shayla.mcneill@tyndall.af.mil

J.R. Kelly
Charles J. Rehwinkel
Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street, Rm. 812
Tallahassee, FL 32399
Kelly.jr@leg.state.fl.us
rehwinkel.charles@leg.state.fl.us

Paula K. Brown
Tampa Electric Company
Administrator, Regulatory Coordination
P.O. Box 111
Tampa, FL 33601-0111
Regdept@tecoenergy.com

R. Alexander Glenn
Deputy General Counsel - Florida
John T. Burnett
Associate General Counsel - Florida
Progress Energy Service Company, LLC
P.O. Box 14042
St. Petersburg, FL 33733
alex.glenn@pgnmail.com
john.burnett@pgnmail.com

Paul Lewis, Jr.
Progress Energy Florida, Inc.
106 East College Avenue, Suite 800
Tallahassee, FL 32301-7740
paul.lewisjr@pgnmail.com

Attorney

Florida Department of
Environmental Protection
Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Rick Scott
Governor

Jennifer Carroll
Lt. Governor

Herschel T. Vinyard, Jr.
Secretary

NOTICE OF PERMIT

RECEIVED
FEB 14 2011
Environmental Services

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

In the Matter of an
Application for Permit by:

Progress Energy Florida
Mr. Thomas Callaghan
1601Weedon Island Drive
St. Petersburg, Florida 33702

PA File No. FL0000132-007-IW1S
Pinellas County
Paul L. Bartow Power Plant
NPDES Permit No. FL0000132

Enclosed is Permit Number FL0000132 to operate the Paul L. Bartow Power Plant, issued under Chapter 403, Florida Statutes.

Monitoring requirements under this permit are effective on the first day of the second month following permit issuance. Until such time, the permittee shall continue to monitor and report in accordance with previously effective permit requirements, if any.

Any party to this order (permit) has the right to seek judicial review of the permit action under Section 120.68, Florida Statutes, by the filing of a notice of appeal under Rules 9.110 and 9.190, Florida Rules of Appellate Procedure, with the Clerk of the Department of Environmental Protection, Office of General Counsel, 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate district court of appeal. The notice of appeal must be filed within 30 days from the date when this document is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Director
Division of Water Resource Management
2600 Blair Stone Road
Tallahassee, FL 32399-2400
(850) 245-8336

Docket No. 110007-EI
Progress Energy Florida
Witness: Patricia Q. West
Exhibit No.__(PQW-1)
Page 11 of 85

EXHIBIT A

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that this INTENT TO ISSUE and all copies were mailed by certified mail before the close of business on 02-07-11 to the listed persons.

[Clerk Stamp]

FILING AND ACKNOWLEDGMENT

FILED, on this date, under section 120.52(7), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

S. Shields 02-07-11
Clerk Date

Certified copies furnished to:
- Mark Nuhfer, NPDES Permitting Section, EPA Region 4, Atlanta, GA
- Chairman, Board of Pinellas County Commissioners
- Patricia Garner, Progress Energy Florida

Copies furnished by intradepartmental mail to:
- Jeff Greenwell, P.E., DEP Tampa
- Yanisa Angulo, P.E., DEP Tampa
- Ilia Balcom, DEP Tampa
- Bill Kelsey, P.G., DEP Tampa
- Nancy Ross, DEP Tallahassee
- Michael Tanski, DEP Tallahassee

2nd AMENDMENT TO THE FACT SHEET AT THE TIME OF PERMIT ISSUANCE

DATE: February 2, 2011

PERMIT NUMBER: FL0000132

PERMITTEE: Progress Energy Florida
Paul L. Bartow Power Plant

1. Changes to the Proposed Permit

The following changes include the permittee's requests to revise the Proposed Permit. The permittee requested the changes through correspondence dated January 26, 2011 and February 2, 2011.

Permit:

a. Page 4, I.A.3. The permittee requested that the description of the monitoring location "EFF-1" be revised to provide a better description of the monitoring location. The Department concurred and the permit was updated to reflect the change.

b. Page 4, I.A.3. The permittee requested an extension of time for the construction of the dock at the end of the discharge canal and installation of the temperature probes at the end of the dock. The permittee requested an extension of 60 days after receiving the Army Corps of Engineers (ACOE) permit for the installation of the probes and an additional 30 days after the dock installation period to commence monitoring at the new location. The ACOE permit, applied for on November 22, 2010, is required to construct the walkway at the end of the discharge canal and the probes will be installed on the walkway. The Department concurred with the request and included the installation schedule in Section VI of the permit.

c. Page 4, I.A.5. The permittee requested that the condition be updated to include the approval use restrictions for Spectrus CT1300. The Department concurred concurred and updated the condition to reflect the change.

d. Page 6, I.A.16. The permittee requested that this condition be deleted as it is duplicative of permit condition I.A.9. The Department concurred and the permit was updated to reflect the change.

e. Page 10, I.C.7. The permittee requested that because disposal will be handled in accordance with 40 CFR Part 761, and certification is not a requirement of the regulatory provision, that the disposal certification at the end of the condition be removed from the permit. The Department concurred and updated the condition to reflect the change.

f. Page 15, IV.3. The permittee requested that because Section III.11 of the Administrative Order accompanying the permit already includes the language, that the condition be removed from the permit. The Department concurred that the language was more appropriate in the time frame of the AO and the permit was updated to reflect the change.

g. Page 16, V.D.1. The permittee requested that the inspection date for 2011 be changed from February 28 to March 31 as there is insufficient time between the issuance date of the permit and the inspection date in the permit condition to schedule an inspection. The Department concurred and updated the condition to reflect the change.

h. Page 17, VI.2. The permittee requested that the schedule be changed so that within 45 days of issuance of the permit, the permittee will submit documentation of the location of the staff gauges to the Southwest District Office instead of receiving approval in 45 days. The Department concurred with the request and updated the permit to reflect the change.

Fact Sheet:

Changes as described above to the draft renewal permit are hereby noted as corresponding changes to the fact sheet where applicable.

2. **Comments by USEPA Region IV Requesting Changes to the Draft Permit and Fact Sheet**

No comments were received from EPA regarding the draft permit and fact sheet.

3. **Other Comments**

a. Page 4, I.A.12. The Southwest District Office requested that the condition be updated to specify that the permittee will collect samples for their multi-sector generic storm water permit (MSGP) prior to commingling with the intake screen wash water. The Department concurred with the request and updated the permit to reflect the change.

STATE OF FLORIDA
INDUSTRIAL WASTEWATER FACILITY PERMIT

PERMITTEE:
Progress Energy Florida

RESPONSIBLE OFFICIAL:

Mr. Thomas Callaghan
Plant Manager

PERMIT NUMBER: FL0000132 (Major)
FILE NUMBER: FL0000132-009-IW1S
ISSUANCE DATE: February 4, 2011
EXPIRATION DATE: February 3, 2016

FACILITY:

Paul L. Bartow Power Plant
1601 Weedon Island Drive
St. Petersburg, FL 33702
Pinellas County

Latitude: 30° 27' 3.2" N Longitude: 84° 23' 58.92" W

This permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.) and applicable rules of the Florida Administrative Code (F.A.C.), and constitutes authorization to discharge to waters of the state under the National Pollutant Discharge Elimination System. This permit is accompanied by an Administrative Order pursuant to paragraphs 403.088(2)(e) and (f), Florida Statutes (F.S.). Compliance with Administrative Order AO-021-TL is a specific requirement of this permit. This permit does not constitute authorization to discharge wastewater other than as expressly stated in this permit. The above named permittee is hereby authorized to operate the facilities in accordance with the documents attached hereto and specifically described as follows:

FACILITY DESCRIPTION:
The facility is an electric generating plant with a total nameplate rating of 1504 megawatts (MW). The existing facility consists of a combined cycle unit system, designated as Unit 4, and four simple cycle combustion turbine peaking units. Unit 4 consists of four ("4-on-1") Siemens SGT6-501F gas turbine-electrical generator set. Exhaust from each gas turbine passes through a separate supplementary gas fired heat recovery steam generator (HRSG). Steam from each HRSG is delivered to a single steam turbine-electrical generator. All units are capable of burning a variable combination of natural gas and No. 2 fuel oil.

In addition, the facility has a boiler, referred to as the Bartow-Anclote Pipeline Heating Boiler, to heat fuel oil being transferred from Progress Energy's Bartow Power Plant to its Anclote Power Plant. The boiler is capable of burning a variable combination of natural gas and No. 2 fuel oil.

The facility has a once-through condenser cooling water system that uses water from Old Tampa Bay, a Class II marine water and Outstanding Florida Water (OFW). The once-through condenser cooling water system has a maximum design intake flow of 562 MGD. Once-through and auxiliary equipment cooling water discharges to the discharge canal and then to Tampa Bay.

WASTEWATER TREATMENT:
Wastewater from the facility consists of once-through cooling water (OTCW), intake screen wash water, metal cleaning wastes (MCW), and low volume wastes (LVW) which includes boiler blowdown, surface and equipment wash down waste, demineralizer regeneration waste, and reverse osmosis reject. Storm water is discharged from plant areas and diked petroleum storage areas. OTCW, intake screen wash water, and storm water discharge to Old Tampa Bay, a Class II marine water and Outstanding Florida Water (OFW). MCW and LVW are treated by neutralization and oil separation, as necessary, and discharged to ground water via the onsite percolation basin system.

The facility produces demineralized water onsite for heat recovery steam generators (HRSG) feedwater make-up, injection into the combustion turbines for nitrogen oxide emission control when operating with fuel oil, power augmentation when requested, and compressor cleaning as needed. The permittee rents or leases demineralizing trailers to treat raw water supplied to the site by the City of St. Petersburg municipal water treatment plant. The treatment process includes reverse osmosis (RO) equipment and a mixed bed polisher. The produced demineralized water is stored in two storage tanks prior to use. The RO reject commingles with the HRSG blowdown prior to discharging into the existing onsite percolation basin system. On average, flows range from 20 to 250 gallons per minute, depending on facility operations and demineralized water requirements.

EFFLUENT DISPOSAL:

Storm Water Discharges: Storm water discharges from Outfalls D-009, D-100, D-200, D-300, D-400, D-500, and D-600 are authorized under a separate Department-issued Multi-Sector General Permit, permit number FLR05G904-001 et seq.

Surface Water Discharge D-001: An existing discharge of once-through cooling water and auxiliary equipment cooling water to Tampa Bay, Class II Waters (WBID 1656). The point of discharge is located approximately at latitude 27° 51' 52.7" N, longitude 82° 36' 36.9" W.

Surface Water Discharge D-009: Existing discharges consisting of storm water and intake screen wash water to Tampa Bay, Class II Waters (WBID 1656). The point of discharge is located approximately at latitude 27° 51' 31" N, longitude 82° 3' 55.9" W.

Land Application G-001: An existing land application system consisting of a percolation basins located approximately at latitude 27° 51' 30.8" N, longitude 82° 36' 7.8" W

IN ACCORDANCE WITH: The limitations, monitoring requirements and other conditions set forth in this Cover Sheet and Part I through Part IX on pages 1 through 26 of this permit.

Docket No. 110007-EI
Progress Energy Florida
Witness: Patricia Q. West
Exhibit No.__(PQW-1)
Page 16 of 85

I. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

A. Surface Water Discharges

1. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge once-through non-contact cooling water and auxiliary equipment cooling water from **Outfall D-001** to Tampa Bay. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.C.3.

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Daily Maximum Monthly Average	Continuous	Pump timer & Curves	FLW-1	
Temperature, Water	Deg F	Max Max	Report Report	Monthly Average Daily Maximum	Continuous	Recorder[1]	EFF-1	
Temperature, Water (Intake)	Deg F	Max Max	Report Report	Monthly Average Daily Maximum	Continuous	Recorder[1]	INT-1	
Temperature Rise (ΔT), Water	Deg F	Max Max	Report Report	Monthly Average Daily Maximum	Continuous	Calculated	EFF-1	
Turbidity	NTU	Max Max	Report Report	Monthly Average Daily Maximum	Quarterly	Grab	EFF-1	See I.A.3
Turbidity (Background)	NTU	Max Max	Report Report	Monthly Average Daily Maximum	Quarterly	Grab	INT-1	See I.A.3
pH	s.u.	Max Min	8.5 6.0	Daily Maximum Daily Minimum	Quarterly	Grab	EFF-1	See I.A.8
		Max	Report	Single Sample	Quarterly	Grab	INT-1	
Temperature, Water	Deg C	Max Max	Report Report	Single Sample Single Sample	Quarterly	Grab	EFF-1 INT-1	See I.A.8
Nitrogen, Ammonia, Total (as N)	mg/L	Max Max	Report Report	Single Sample Single Sample	Quarterly	Grab	EFF-1 INT-1	See I.A.8
Ammonia, Total Unionized (as NH_3)	mg/L	Max Max	Report Report	Single Sample Single Sample	Quarterly	Calculated	EFF-1 INT-1	See I.A.8
Nitrogen, Kjeldahl, Total (as N)	mg/L	Max Max	Report Report	Single Sample Single Sample	Quarterly	Grab	EFF-1 INT-1	
Nitrite plus Nitrate, Total 1 det. (as N)	mg/L	Max Max	Report Report	Single Sample Single Sample	Quarterly	Grab	EFF-1 INT-1	
Nitrogen, Total	mg/L	Max Max	Report Report	Single Sample Single Sample	Quarterly	Grab	EFF-1 INT-1	
Phosphorus, Total (as P)	mg/L	Max Max	Report Report	Single Sample Single Sample	Quarterly	Grab	EFF-1 INT-1	
Phosphate, Ortho (as PO4)	mg/L	Max Max	Report Report	Single Sample Single Sample	Quarterly	Grab	EFF-1 INT-1	
Chronic Whole Effluent Toxicity, 7-Day IC25 (Mysidopsis Bahia)	percent	Min	100	Single Sample	Quarterly	24-hr Composite	EFF-1	See I.A.11
Chronic Whole Effluent Toxicity, 7-Day IC25 (Menidia beryllina)	percent	Min	100	Single Sample	Quarterly	24-hr Composite	EFF-1	See I.A.11

2. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.A.1. and as described below:

[1] Flow meters and thermometers shall be calibrated at least once a year in accordance with the manufacturer recommendations. Calibration records shall be maintained on-site in accordance with Section V.A of this permit.

Monitoring Site Number	Description of Monitoring Site
FLW-1	Flow calculation for Outfall D-001
EFF-1	Condenser outlet of once-through cooling water system (pre-construction of the new dock); new dock at the end of discharge canal (post-construction of the new dock see Permit Condition VI.2).
INT-1	After the debris filter and prior to the water box inlet.

3. The limit for "Turbidity" shall be calculated as follows:

   Limit = Background Turbidity + 29 NTU

   The measured effluent value shall be recorded on the DMR in the parameter row for "Turbidity (effluent)." The measured background value shall be recorded on the DMR in the parameter row for "Turbidity (background)" The calculated effluent limit shall be recorded on the DMR in the parameter row for "Turbidity (calculated limit)." Compliance with the effluent limitation is determined by calculating the difference between the measured effluent value and the calculated. The compliance value shall be recorded on the DMR in the parameter row for "Turbidity (effluent minus calculated limit)." The compliance value shall not exceed 0.00.

   [62-302.530(69)]

4. The permittee is authorized to add FoamTrol AF3561, at a maximum dosing rate of 1.0 mg/L, to the once-through cooling water. The permittee shall maintain records onsite for each application in accordance with Section V.A of this permit.

5. The permittee is authorized to discharge Spectrus CT1300 from the once-through cooling water system for not more than six hours in any one day and not more frequently than once every four days. No more than one condenser shall discharge Spectrus CT1300 at any given time. At a minimum, an equal number of pumps on the non-treated condenser as the treated condenser shall be operated during treatment with Spectrus CT1300. The dosage rate shall not exceed 3.0 mg/L and the effluent concentration at monitoring location EFF-1 shall be non-detect. The permittee shall maintain records onsite for each application in accordance with Section V.A of this permit.

6. The permittee shall not add chlorine or bromine-based products to either the once-through or the auxiliary equipment cooling water without Department approval.

7. The permittee shall not add nitrogen or phosphorous containing products to either the once-through or the auxiliary equipment cooling water without Department approval.

8. Samples for pH and temperature (grab) shall be taken simultaneously with each total ammonia grab sample. Un-ionized ammonia shall be calculated in accordance with the procedure provided by the Department (refer to the website www.dep.state.fl.us./labs/library/index.htm). All measured values for pH, temperature, and total ammonia used to calculate an un-ionized ammonia value shall be reported as an attachment to the Discharge Monitoring Report (DMR). All calculated un-ionized ammonia values shall be reported on the attachment. The daily maximum and monthly average values for un-ionized ammonia for each reporting period shall be reported on the DMR.

9. The permittee shall maintain the current intake through-screen velocity such that the existing maximum velocity is not exceeded.

10. The permittee shall develop a plan in accordance with the schedule in Condition VI.3 to help return live fish, shellfish, and other aquatic organisms collected or trapped on the intake screens to their natural habitat. Other material shall be removed from the intake screens and disposed of in accordance with all existing Federal, State and/or Local laws and regulations that apply to waste disposal. Such material shall not be returned to the receiving waters.

11. The permittee shall comply with the following requirements to evaluate chronic whole effluent toxicity of the discharge from Outfall D-001 when a chemical additive (see Permit Conditions I.A.4 and 5) is present.

a. Effluent Limitation
   (1) In any routine or additional follow-up test for chronic whole effluent toxicity, the 25 percent inhibition concentration (IC25) shall not be less than 100% effluent. *[Rules 62-302.530(61) and 62-4.241(1)(b), F.A.C.]*
   (2) For acute whole effluent toxicity, the 96-hour LC50 shall not be less than 100% effluent in any test. *[Rules 62-302.500(1)(a)4. and 62-4.241(1)(a), F.A.C.]*

b. Monitoring Frequency
   (1) Routine toxicity tests shall be conducted once every three months, the first starting within 60 days of the issuance date of this permit and lasting for the duration of this permit.
   (2) Upon completion of four consecutive, valid routine tests that demonstrate compliance with the effluent limitation in 11.a.(1) above, the permittee may submit a written request to the Department for a reduction in monitoring frequency to once every six months. The request shall include a summary of the data and the complete bioassay laboratory reports for each test used to demonstrate compliance. The Department shall act on the request within 45 days of receipt. Reductions in monitoring shall only become effective upon the Department's written confirmation that the facility has completed four consecutive valid routine tests that demonstrate compliance with the effluent limitation in 11.a.(1) above.
   (3) If a test within the sequence of the four is deemed invalid based on the acceptance criteria in EPA-821-R-02-014, but is replaced by a repeat valid test initiated within 21 days after the last day of the invalid test, the invalid test will not be counted against the requirement for four consecutive valid tests for the purpose of evaluating the reduction of monitoring frequency.

c. Sampling Requirements
   (1) For each routine test or additional follow-up test conducted, a total of three 24-hour composite samples of final effluent shall be collected and used in accordance with the sampling protocol discussed in EPA-821-R-02-014, Section 8.
   (2) The first sample shall be used to initiate the test. The remaining two samples shall be collected according to the protocol and used as renewal solutions on Day 3 (48 hours) and Day 5 (96 hours) of the test.
   (3) Samples for routine and additional follow-up tests shall not be collected on the same day.

d. Test Requirements
   (1) Routine Tests: All routine tests shall be conducted using a control (0% effluent) and a minimum of five test dilutions: 100%, 50%, 25%, 12.5%, and 6.25% final effluent.
   (2) The permittee shall conduct 7-day survival and growth chronic toxicity tests with a mysid shrimp, **Americamysis (Mysidopsis) bahia**, Method 1007.0, and an inland silverside, **Menidia beryllina**, Method 1006.0, concurrently.
   (3) All test species, procedures and quality assurance criteria used shall be in accordance with **Short-term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Marine and Estuarine Organisms**, 3rd Edition, EPA-821-R-02-014. Any deviation of the bioassay procedures outlined herein shall be submitted in writing to the Department for review and approval prior to use. In the event the above method is revised, the permittee shall conduct chronic toxicity testing in accordance with the revised method.
   (4) The control water and dilution water used shall be artificial sea salts as described in EPA-821-R-02-014, Section 7.2. The test salinity shall be determined as follows:
      (a) For the **Americamysis bahia** bioassays, the effluent shall be adjusted to a salinity of 20 parts per thousand (ppt) with artificial sea salts. The salinity of the control/dilution water (0% effluent) shall be 20 ppt. If the salinity of the effluent is greater than 20 ppt, no salinity adjustment shall be made to the effluent and the test shall be run at the effluent salinity. The salinity of the control/dilution water shall match the salinity of the effluent.
      (b) For the **Menidia beryllina** bioassays, if the effluent salinity is less than 5ppt, the salinity shall be adjusted to 5 ppt with artificial sea salts. The salinity of the control/dilution water (0% effluent) shall be 5 ppt. If the salinity of the effluent is greater than 5 ppt, no salinity adjustment shall be made to the effluent and the test shall be run at the effluent salinity. The salinity of the control/dilution water shall match the salinity of the effluent.

(c) If the salinity of the effluent requires adjustment, a salinity adjustment control should be prepared and included with each bioassay. The salinity adjustment control is intended to identify toxicity resulting from adjusting the effluent salinity with artificial sea salts. To prepare the salinity adjustment control, dilute the control/dilution water to the salinity of the effluent and adjust the salinity of the salinity adjustment control at the same time and to the same salinity that the salinity of the effluent is adjusted using the same artificial sea salts.

e. Quality Assurance Requirements

(1) A standard reference toxicant (SRT) quality assurance (QA) chronic toxicity test shall be conducted with each species used in the required toxicity tests either concurrently or initiated no more than 30 days before the date of each routine or additional follow-up test conducted. Additionally, the SRT test must be conducted concurrently if the test organisms are obtained from outside the test laboratory unless the test organism supplier provides control chart data from at least the last five monthly chronic toxicity tests using the same reference toxicant and test conditions. If the organism supplier provides the required SRT data, the organism supplier's SRT data and the test laboratory's monthly SRT-QA data shall be included in the reports for each companion routine or additional follow-up test required.

(2) If the mortality in the control (0% effluent) exceeds 20% for either species in any test or any test does not meet "test acceptability criteria", the test for that species (including the control) shall be invalidated and the test repeated. Test acceptability criteria for each species are defined in EPA-821-R-02-014, Section 14.12 (**Americamysis bahia**) and Section 13.12 (**Menidia beryllina**). The repeat test shall begin within 21 days after the last day of the invalid test.

(3) If 100% mortality occurs in all effluent concentrations for either species prior to the end of any test and the control mortality is less than 20% at that time, the test (including the control) for that species shall be terminated with the conclusion that the test fails and constitutes non-compliance.

(4) Routine and additional follow-up tests shall be evaluated for acceptability based on the observed dose-response relationship as required by EPA-821-R-02-014, Section 10.2.6., and the evaluation shall be included with the bioassay laboratory reports.

f. Reporting Requirements

(1) Results from all required tests shall be reported on the Discharge Monitoring Report (DMR) as follows:

(a) Routine and Additional Follow-up Test Results: The calculated IC25 for each test species shall be entered on the DMR.

(2) A bioassay laboratory report for each routine test shall be prepared according to EPA-821-R-02-014, Section 10, Report Preparation and Test Review, and mailed to the Department at the address below within 30 days after the last day of the test.

(3) For additional follow-up tests, a single bioassay laboratory report shall be prepared according to EPA-821-R-02-014, Section 10, and mailed within 30 days after the last day of the second valid additional follow-up test.

(4) Data for invalid tests shall be included in the bioassay laboratory report for the repeat test.

(5) The same bioassay data shall not be reported as the results of more than one test.

(6) All bioassay laboratory reports shall be sent to:

Florida Department of Environmental Protection
Southwest District
13051 N. Telecom Parkway
Temple Terrace, Florida 33637

g. Test Failures

(1) A test fails when the test results do not meet the limits in 11.a.(1).

(2) Additional Follow-up Tests:

(a) If a routine test does not meet the chronic toxicity limitation in 11.a.(1) above, the permittee shall notify the Department at the address above within 21 days after the last day of the failed routine test and conduct two additional follow-up tests on each species that failed the test in accordance with 11.d.

(b) The first test shall be initiated within 28 days after the last day of the failed routine test. The remaining additional follow-up tests shall be conducted weekly thereafter until a total of two valid additional follow-up tests are completed.

(c) The first additional follow-up test shall be conducted using a control (0% effluent) and a minimum of five dilutions: 100%, 50%, 25%, 12.5%, and 6.25% effluent. The permittee may modify the dilution series in the second additional follow-up test to more accurately bracket the toxicity such that at least two dilutions above and two dilutions below the target concentration and a control (0% effluent) are run. All test results shall be analyzed according to the procedures in EPA-821-R-02-014.

(3) In the event of three valid test failures (whether routine or additional follow-up tests) within a 12-month period, the permittee shall notify the Department within 21 days after the last day of the third test failure.

(a) The permittee shall submit a plan for correction of the effluent toxicity within 60 days after the last day of the third test failure.
(b) The Department shall review and approve the plan before initiation.
(c) The plan shall be initiated within 30 days following the Department's written approval of the plan.
(d) Progress reports shall be submitted quarterly to the Department at the address above.
(e) During the implementation of the plan, the permittee shall conduct quarterly routine whole effluent toxicity tests in accordance with 11.d. Additional follow-up tests are not required while the plan is in progress. Following completion or termination of the plan, the frequency of monitoring for routine and additional follow-up tests shall return to the schedule established in 11.b.(1). If a routine test is invalid according to the acceptance criteria in EPA-821-R-02-014, a repeat test shall be initiated within 21 days after the last day of the invalid routine test.
(f) Upon completion of four consecutive quarterly valid routine tests that demonstrate compliance with the effluent limitation in 11.a.(1) above, the permittee may submit a written request to the Department to terminate the plan. The plan shall be terminated upon written verification by the Department that the facility has passed at least four consecutive quarterly valid routine whole effluent toxicity tests. If a test within the sequence of the four is deemed invalid, but is replaced by a repeat valid test initiated within 21 days after the last day of the invalid test, the invalid test will not be counted against the requirement for four consecutive quarterly valid routine tests for the purpose of terminating the plan.

(4) If chronic toxicity test results indicate greater than 50% mortality within 96 hours in an effluent concentration equal to or less than the effluent concentration specified as the acute toxicity limit in 11.(a)(2), the Department may revise this permit to require acute definitive whole effluent toxicity testing.

(5) The additional follow-up testing and the plan do not preclude the Department taking enforcement action for acute or chronic whole effluent toxicity failures.

[62-4.241, 62-620.620(3)]

12. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge storm water and intake screen wash water from Outfall D-009. Discharge of intake screen wash water and storm water is permitted without monitoring requirements provided the permittee collects samples for storm water as required under storm water MSGP Permit number FLR05G904-001 et seq. prior to comingling with the intake screen wash water.

13. The permittee shall not add any chemicals to the intake screen wash water.

14. No surface water discharge from this facility shall contain components that settle to form putrescent deposits or float as debris, scum, oil, or other matter. *[62-302.500(1)(a)]*

B. Land Application Systems

1. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge low volume wastes (including boiler blowdown, reverse osmosis reject water, surface and equipment wash down waste, and demineralizer regeneration waste) and metal cleaning wastewater to Land Application System G-001. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.C.3.

Parameter	Units	Max/ Min	Effluent Limitations: Limit	Effluent Limitations: Statistical Basis	Monitoring Requirements: Frequency of Analysis	Monitoring Requirements: Sample Type	Monitoring Requirements: Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Monthly Average Daily Maximum	Continuous	Meter[2]	FLW-7	
Temperature, Water	Deg F	Max	Report	Daily Maximum	Quarterly	Grab	EFF-7	
pH	s.u.	Max Min	Report Report	Daily Maximum Daily Minimum	Quarterly	In-situ	EFF-7	
Solids, Total Suspended	mg/L	Max	Report	Daily Maximum	Quarterly	24-hr TPC	EFF-7	
Specific Conductance	umhos/ cm	Max	Report	Daily Maximum	Quarterly	In-situ	EFF-7	
Aluminum, Total Recoverable	ug/L	Max	Report	Daily Maximum	Quarterly	24-hr TPC	EFF-7	
Arsenic, Total Recoverable	ug/L	Max	Report	Daily Maximum	Quarterly	24-hr TPC	EFF-7	
Chromium, Total Recoverable	ug/L	Max	Report	Daily Maximum	Quarterly	24-hr TPC	EFF-7	
Iron, Total Recoverable	ug/L	Max	Report	Daily Maximum	Quarterly	24-hr TPC	EFF-7	
Magnesium, Total Recoverable	ug/L	Max	Report	Daily Maximum	Quarterly	24-hr TPC	EFF-7	
Nickel, Total Recoverable	ug/L	Max	Report	Daily Maximum	Quarterly	24-hr TPC	EFF-7	
Sodium, Total Recoverable	mg/L	Max	Report	Daily Maximum	Quarterly	24-hr TPC	EFF-7	
Alpha, Gross Particle Activity	pCi/L	Max	Report	Daily Maximum	Quarterly	24-hr TPC	EFF-7	
Radium 226 + Radium 228, Total	pCi/L	Max	Report	Daily Maximum	Quarterly	24-hr TPC	EFF-7	

2. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.1 and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-7	At the flow meters.
EFF-7	Effluent prior to discharge into the pond.

C. Other Limitations and Monitoring and Reporting Requirements

1. The sample collection, analytical test methods, and method detection limits (MDLs) applicable to this permit shall be conducted using a sufficiently sensitive method to ensure compliance with applicable water quality standards and effluent limitations and shall be in accordance with Rule 62-4.246, Chapters 62-160 and 62-601, F.A.C., and 40 CFR 136, as appropriate. The list of Department established analytical methods, and corresponding MDLs (method detection limits) and PQLs (practical quantitation limits), which is titled "FAC 62-4 MDL/PQL Table (April 26, 2006)" is available at http://www.dep.state.fl.us/labs/library/index.htm. The MDLs and PQLs as described in this list shall constitute the minimum acceptable MDL/PQL values and the Department shall not accept results for which the laboratory's MDLs or PQLs are greater than those described above unless alternate MDLs and/or PQLs have been specifically approved by the Department for this permit. Any method included in the list may be used for reporting as long as it meets the following requirements:
   a. The laboratory's reported MDL and PQL values for the particular method must be equal or less than the corresponding method values specified in the Department's approved MDL and PQL list;
   b. The laboratory reported MDL for the specific parameter is less than or equal to the permit limit or the applicable water quality criteria, if any, stated in Chapter 62-302, F.A.C. Parameters that are listed as "report only" in the permit shall use methods that provide an MDL, which is equal to or less than the applicable water quality criteria stated in 62-302, F.A.C.; and
   c. If the MDLs for all methods available in the approved list are above the stated permit limit or applicable water quality criteria for that parameter, then the method with the lowest stated MDL shall be used.

[2] Flow meters shall be calibrated at least once a year in accordance with the manufacturer recommendations. Calibration records shall be maintained on-site in accordance with Condition V.A.2 of this permit.

When the analytical results are below method detection or practical quantitation limits, the permittee shall report the actual laboratory MDL and/or PQL values for the analyses that were performed following the instructions on the applicable discharge monitoring report.

Where necessary, the permittee may request approval of alternate methods or for alternative MDLs or PQLs for any approved analytical method. Approval of alternate laboratory MDLs or PQLs are not necessary if the laboratory reported MDLs and PQLs are less than or equal to the permit limit or the applicable water quality criteria, if any, stated in Chapter 62-302, F.A.C. Approval of an analytical method not included in the above-referenced list is not necessary if the analytical method is approved in accordance with 40 CFR 136 or deemed acceptable by the Department. *[62-4.246, 62-160]*

2. The permittee shall provide safe access points for obtaining representative influent and effluent samples which are required by this permit. *[62-620.320(6)]*

3. Monitoring requirements under this permit are effective on the first day of the second month following permit issuance. Until such time, the permittee shall continue to monitor and report in accordance with previously effective permit requirements, if any. During the period of operation authorized by this permit, the permittee shall complete and submit to the Department Discharge Monitoring Reports (DMRs) in accordance with the frequencies specified by the REPORT type (i.e. monthly, toxicity, quarterly, semiannual, annual, etc.) indicated on the DMR forms attached to this permit. Monitoring results for each monitoring period shall be submitted in accordance with the associated DMR due dates below.

REPORT Type on DMR	Monitoring Period	Due Date
Monthly or Toxicity	first day of month - last day of month	28th day of following month
Quarterly	January 1 - March 31 April 1 - June 30 July 1 - September 30 October 1 - December 31	April 28 July 28 October 28 January 28
Semiannual	January 1 - June 30 July 1 - December 30	July 28 January 28
Annual	January 1 - December 31	January 28

DMRs shall be submitted for each required monitoring period including months of no discharge. The permittee may submit either paper or electronic DMR form(s). If submitting paper DMR form(s), the permittee shall make copies of the attached DMR form(s). If submitting electronic DMR form(s), the permittee shall use a Department-approved electronic DMR system.

The electronic submission of DMR forms shall accepted only if approved in writing by the Department. For purposes of determining compliance with this permit, data submitted in electronic format is legally equivalent to data submitted on signed and certified DMR forms.

The permittee shall submit the completed DMR form(s) to the Department by the twenty-eighth (28th) of the month following the month of operation at the addresses specified below:

Florida Department of Environmental Protection
Wastewater Compliance Evaluation Section, Mail Station 3551
Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

And

Florida Department of Environmental Protection
Southwest District
13051 N. Telecom Parkway
Temple Terrace, Florida 33637

[62-620.610(18)]

4. Unless specified otherwise in this permit, all reports and other information required by this permit, including 24-hour notifications, shall be submitted to or reported to, as appropriate, the Department's Southwest District Office at the address specified below:

   Florida Department of Environmental Protection
   Southwest District
   13051 N. Telecom Parkway
   Temple Terrace, Florida 33637

   Phone Number - (813) 632-7600
   FAX Number - (813) 632-7665 (All FAX copies and e-mails shall be followed by original copies.)

   [62-620.305]

5. All reports and other information shall be signed in accordance with the requirements of Rule 62-620.305, F.A.C. [62-620.305]

6. If there is no discharge from the facility on a day when the facility would normally sample, the sample shall be collected on the day of the next discharge. *[62-620.320(6)]*

7. There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid. The permittee shall dispose of all known PCB equipment, articles, and wastes in accordance with 40 CFR 761.

8. Discharge of any product registered under the Federal Insecticide, Fungicide, and Rodenticide Act to any waste stream which ultimately may be released to waters of the State is prohibited unless specifically authorized elsewhere in this permit. This requirement is not applicable to products used for lawn and agricultural purposes or to the use of herbicides if used in accordance with labeled instructions and any applicable State permit.

   A permit revision from the Department shall be required prior to the use of any biocide or chemical additive used in the cooling system or any other portion of the treatment system which may be toxic to aquatic life. The permit revision request shall include:

   a. Name and general composition of biocide or chemical
   b. Frequencies of use
   c. Quantities to be used
   d. Proposed effluent concentrations
   e. Acute and/or chronic toxicity data (laboratory reports shall be prepared according to Section 12 of EPA document no. EPA-821-R-02-012 EP entitled, Methods for Measuring the Acute Toxicity of Effluents and Receiving Waters for Freshwater and Marine Organisms, or most current addition.)
   f. Product data sheet
   g. Product label

   The Department shall review the above information to determine if a major or minor permit revision is necessary. Discharge associated with the use of such biocide or chemical is not authorized without a permit revision by the Department. Permit revisions shall be processed in accordance with the requirements of Chapter 62-620, F.A.C.

9. The permittee shall report the following each month for each application of all Department-approved biocides and chemical additives used in the cooling system or any other portion of the treatment system which may be toxic to aquatic life:

   a. the date of each application:
   b. the quantity added to each cooling system or any other portion of the treatment system; and
   c. the number of applications each week.

10. Discharge of any waste resulting from the combustion of toxic, hazardous, or metal cleaning wastes to any waste stream which ultimately discharges to waters of the State is prohibited, unless specifically authorized elsewhere in this permit.

11. The permittee shall not store coal, soil, or other similar erodible materials in a manner in which runoff is uncontrolled, or conduct construction activities in a manner which produces uncontrolled runoff.

12. Unless otherwise specifically permitted in this permit, there shall be no point source discharges of any wastes to waters of the State, or to any waste stream which enters such waters. The permittee shall operate and maintain loading and unloading facilities in such a manner in order to preclude spillage of coal, chemicals, etc., used at the facility, and shall take all actions necessary to clean-up and control any such spill which may occur.

13. Any water drained from the fuel oil storage tanks or other water which meets the definition of "Petroleum Contact Water" as defined in Rule 62-740.030(1), F.A.C., shall be disposed at a Department-approved facility in accordance with Chapter 62-740, F.A.C.

14. The permittee shall develop a Plan of Study (POS) pursuant to the schedule in Permit Condition VI.5., including implementation schedule, to evaluate the concentrations of dissolved oxygen (DO) in the cooling water intake and discharge. The POS shall incorporate quarterly summary reports.

II. SLUDGE MANAGEMENT REQUIREMENTS

1. The permittee shall be responsible for proper treatment, management, use, and disposal of its sludges. *[62-620.320(6)]*

2. Storage, transportation, and disposal of sludge/solids characterized as hazardous waste shall be in accordance with requirements of Chapter 62-730, F.A.C. *[62-730]*

3. Vegetation and materials removed from intake screens and vegetation, sediments and sludge excavated from the settling basins and percolation basins must be properly stored onsite until they are disposed in accordance with requirements in Chapter 62-701, F.A.C., and other applicable State and Federal requirements.

III. GROUND WATER REQUIREMENTS

A. Decommission Requirements

1. Ground water monitoring wells designated as MW-1, MW-2, MW-5, MW-7 and MW 8 shall be removed from the Ground Water Monitoring Plan (GWMP). Within 45 days of permit issuance, the permittee shall properly plug and abandon these monitoring wells in accordance with Rule 62-532.500(4), F.A.C.

2. Within 30 days of plugging ground water monitor wells, the Department requests that the permittee submit the following information for each monitor well:

   a. A copy of the Florida Water Management District (WMD), State of Florida Permit Application to Construct, Repair, Modify or Abandon a Well, Form LEG-R.040.00, and

   b. Any other applicable WMD documentation

   [62-520.600(6)(k)]

B. Construction Requirements

1. The permittee shall construct a replacement ground water monitoring well for MWC-6 (replacement for MW-6) as depicted in the Groundwater Monitoring Plan dated October 27, 2010. The following requirements apply to the construction of the well:

   a. New monitoring well (MWC-6) shall be located adjacent to the existing MW-6; and

   b. screen depth shall be no deeper than necessary to intercept the seasonal low ground water table; and

c. screen interval shall be no greater than 10 feet in length; and

d. the bottom of the monitoring well shall be above the highest tide elevation; and

e. original MW-6 shall be properly plugged and abandoned in accordance with Rule 62-532.500(4), F.A.C.

2. The permittee shall construct ground water monitoring well MWC-9 as described in the Groundwater Monitoring Plan dated October 27, 2010. The following requirements apply to the construction of the well:

   a. screen depth shall be no deeper than necessary to intercept the seasonal low ground water table; and

   b. screen interval shall be no greater than 10 feet in length; and

   c. the bottom of the monitoring well shall be above the highest tide elevation.

3. The permittee shall give at least 72-hours notice to the Department's Southwest District Office, prior to the installation of any monitoring wells detailed in this permit. *[62-620.320(6) and 62-520.600(6) (h)]*

4. Prior to construction of new ground water monitoring wells, a soil boring shall be made at each new monitoring well location in order to establish the well depth and screen interval. *[62-520.900(3)]*

5. Within 30 days after installation of a monitoring well, the permittee shall submit to the Department's Southwest District Office detailed information on the well's location and construction on the attached DEP Form(s) 62-520.900(3), Monitor Well Completion Report. *[62-520.600(6)(j)]*

6. Within 60 days after completion of construction of the ground water monitoring wells, a properly scaled figure depicting monitor well locations (active and abandoned) with identification numbers shall be submitted. The figure shall also include (or attach) the monitoring well, top of casing, and ground surface elevations referenced to National Geodetic Vertical Datum (NGVD) of 1929 to the nearest 0.01 foot, along with monitor well location latitude and longitude to the nearest 0.1 second. *[62-520.600(6) (i)]*

7. In Districts where applicable, within 30 days of completion of construction of new ground water monitor wells, the Department requests that the permittee submit the following information for each monitor well:

   a. A copy of the Florida Water Management District (WMD), State of Florida Permit Application to Construct, Repair, Modify or Abandon a Well, Form LEG-R.040.00, and

   b. A copy of the WMD Well Completion Report, Form LEG-R.005.01

   [62-520.600(6)(j)]

8. Within 30 days of installation of all new wells, the permittee shall sample all new ground water monitoring wells for the Primary and Secondary Drinking Water parameters included in Rule 62-550, Florida Administrative Code, Public Drinking Water Systems (excluding asbestos, acrylamide, Dioxin, butachlor, epichlorohydrin, pesticides, and PCBs, unless reasonably expected to be a constituent of the discharge or an artifact of the site). In addition, volatile organics and extractable semivolatile organics shall be analyzed. Results of this sampling shall be submitted to the Department within 60 days after sampling. *[62-520.600]*

C. Operational Requirements

1. During the period of operation authorized by this permit, the permittee shall continue to sample ground water at the existing monitoring wells identified in item III.C.2 below, in accordance with this permit and the approved ground water monitoring plan prepared in accordance with Rule 62-520.600, F.A.C. Within 90 days of placing the new or modified wastewater facility into operation, or installation of new monitoring wells, whichever occurs sooner, the permittee shall begin sampling ground water at the new monitoring wells identified in item III.C.2 below in accordance with this permit and the approved ground water monitoring plan. *[62-520.600]*

2. The following monitoring wells shall be sampled for Groundwater Monitoring Plan:

Monitoring Well ID	Alternate Well Name and/or Description of Monitoring Location	Depth (Feet)	Aquifer Monitored	New or Existing
MWB-3 (Former MW-3)	Background Well located at northern end of the site	20.0	Surficial	Existing
MWI-4 (Former MW-4A)	Intermediate Well located west of Pond 1C (aka Pond 2N)	22.0	Surficial	Existing
MWC-6 (replacement for MW-6)	Compliance Well to be located south of Pond 2 (aka Pond 2S)		Surficial	New
MWC-9	Compliance Well to be located along eastern edge of the ZOD		Surficial	New

MWB = Background; MWI = Intermediate; MWC = Compliance; MWP = Piezometer
*Piezometers shall be sampled for water level only

[62-520.600]

3. The monitor wells specified in Condition III.C.2 shall be sampled for the parameters listed below:

Parameter Name	Compliance Well Limit	Units	Sample Type	Monitoring Frequency
Arsenic, Total Recoverable	10	UG/L	Grab	Quarterly
Manganese, Total Recoverable	50	UG/L	Grab	Quarterly
Toluene	1.0	MG/L	Grab	Quarterly
Solids, Total Dissolved (TDS)	500	MG/L	Grab	Quarterly
Turbidity[3]	Report	NTU	In-situ	Quarterly
Water Level Relative to NGVD	Report	FEET	In-situ	Quarterly
pH[3]	6.5-8.5	SU	In-situ	Quarterly
Temperature (F), Water[3]	Report	DEG.F	In-situ	Quarterly
Oxygen, Dissolved (DO)[3]	Report	MG/L	In-situ	Quarterly
Chloride (as Cl)	250	MG/L	Grab	Quarterly
Specific Conductance[3]	Report	UMHO/CM	In-situ	Quarterly
Nitrogen, Total	Report	MG/L	Grab	Quarterly
Nitrogen, Nitrate, Total (as N)	10.0	MG/L	Grab	Quarterly
Nitrogen, Nitrite, Total (as N)	1.0	MG/L	Grab	Quarterly
Phosphorus, Total (as P)	Report	MG/L	Grab	Quarterly
Alpha, Gross Particle Activity	15	pCi/L	Grab	Quarterly
Radium 226 + Radium 228, Total	5	pCi/L	Grab	Quarterly
Magnesium, Total Recoverable	Report	MG/L	Grab	Quarterly
Mercury, Total Recoverable	2	UG/L	Grab	Quarterly
Cadmium, Total Recoverable	5	UG/L	Grab	Quarterly
Lead, Total Recoverable	15	UG/L	Grab	Quarterly
Aluminum, Total Recoverable	0.2	MG/L	Grab	Quarterly
Nickel, Total Recoverable	100	UG/L	Grab	Quarterly
Chromium, Total Recoverable	100	UG/L	Grab	Quarterly
Sodium, Total Recoverable	160	MG/L	Grab	Quarterly

[62-520.600(11)(b)]

[3] The field parameters shall be sampled per DEP-SOP-001/01, FS 2200 Groundwater Sampling, Figure FS 2200-2 Groundwater Purging Procedure and recorded on Form FD 9000-24, Groundwater Sampling Log (both documents attached to this permit). The sampling logs shall be submitted with each groundwater Part D DMR. The field parameters to be reported on Part D of GW DMR shall be the last sample recorded on FD 9000-24.

4. *All ground water quality criteria specified in Chapter 62-520, F.A.C., shall be met at the edge of the zone of* discharge. The zone of discharge for this project shall extend horizontally along the ground surface 100 feet from the edge of the pollution source or to the permittee's property boundary, whichever is less, and vertically to the base of the surficial aquifer. *[62-520.200(26)] [62-520.465]*

5. The permittee's discharge to ground water shall not cause a violation of water quality standards for ground waters at the boundary of the zone of discharge in accordance with Rules 62-520.400 and 62-520.420, F.A.C.

6. The permittee's discharge to ground water shall not cause a violation of the minimum criteria for ground water specified in Rule 62-520.400, F.A.C., within the zone of discharge. *[62-520.400 and 62-520.420(4)]*

7. If the concentration for any constituent listed in Permit Condition III.C.3 in the natural background quality of the ground water is greater than the stated maximum, or in the case of pH is also less than the minimum, the *representative background quality shall be the prevailing standard. [62-520.420(2)]*

8. Water levels shall be recorded prior to evacuating the well for sample collection. Elevation references shall include the top of the well casing and land surface at each well site (NGVD allowable) at a precision of plus or minus 0.01 feet. *[62-520.600(11)(c)]*

9. Ground water monitoring wells shall be purged prior to sampling to obtain a representative sample. *[62-160.210]*

10. Analyses shall be conducted on un-filtered samples, unless filtered samples have been approved by the Department as being more representative of ground water conditions. *[62-520.310(5)]*

11. If any monitoring well becomes inoperable or damaged to the extent that sampling or well integrity may be affected, the permittee shall notify the Department's office that issued the permit within two business days from discovery, and a detailed written report shall follow within ten days after notification to the Department. The written report shall detail what problem has occurred and remedial measures that have been taken to prevent recurrence or request approval for replacement of the monitoring well. All monitoring well design and replacement shall be approved by the Department before installation. *[62-520.600(6)(l)]*

12. With the application for permit renewal, the permittee shall submit, to the Southwest District Office, the results of sampling all four (4) *monitoring wells specified in the Department-approved monitoring plan for the Primary* and Secondary drinking water parameters included in Chapter 62-550, F.A.C., (excluding asbestos, acrylamide, Dioxin, butachlor, epichlorohydrin, pesticides, and PCBs, unless reasonably expected to be a constituent of the discharge or an artifact of the site). Sampling shall occur no sooner than 180 days before submittal of the renewal application. *[62-520.600]*

13. All piezometers and monitoring wells not part of the approved ground water monitoring plan are to be plugged and abandoned in accordance with Rule 62-532.500(4), F.A.C., unless there is intent for their future use. *[62-532.500(4)]*

14. Ground water monitoring test results shall be submitted on Part D of DEP Form 62-620.910(10) (attached) and shall be submitted to the address specified in I.C.3. Results shall be submitted with the DMR for each month listed in the following schedule.

SAMPLE PERIOD	REPORT DUE DATE
January – March	April 28
April - June	July 28
July - September	October 28
October - December	January 28

[62-520.600(11)(b)]

IV. ADDITIONAL LAND APPLICATION REQUIREMENTS

1. The bottoms for the settling basins and percolation basins shall be cleaned out periodically, or when necessary, to remove the excess buildup of sediments, and to ensure continuous percolation capability for the percolation basins. Materials removed from the basins shall be managed as required in Section II "Sludge Management Requirements" of this permit. Routine weed control and regular maintenance of basin embankments and access areas are required.

2. The freeboard of the percolation basins shall be a minimum of three feet.[4]

3. The permittee shall not discharge water from the percolation basins to surface waters of the State.

4. Water levels in the percolation basins shall be recorded weekly on Part B of the Discharge Monitoring Reports. Part B of the Discharge Monitoring Reports shall be submitted quarterly in accordance with the schedule in Condition I.C.3.

V. DESIGN, CONSTRUCTION, OPERATION AND MAINTENANCE REQUIREMENTS

A. General Operation and Maintenance Requirements

1. During the period of operation authorized by this permit, the wastewater facilities shall be operated under the supervision of a person who is qualified by formal training and/or practical experience in the field of water pollution control. *[62-620.320(6)]*

2. The permittee shall maintain the following records and make them available for inspection on the site of the permitted facility.

   a. Records of all compliance monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, including, if applicable, a copy of the laboratory certification showing the certification number of the laboratory, for at least three years from the date the sample or measurement was taken;

   b. Copies of all reports required by the permit for at least three years from the date the report was prepared;

   c. Records of all data, including reports and documents, used to complete the application for the permit for at least three years from the date the application was filed;

   d. Records of all offsite disposal of vegetation and materials removed from intake screens and vegetation, sediments and sludge removed from wastewater and stormwater basins

   e. A copy of the current permit;

   f. A copy of any required record drawings; and

   g. Copies of the logs and schedules showing plant operations and equipment maintenance for three years from the date of the logs or schedules.

   [62-620.350]

B. Storm Water Requirements

1. The discharge of storm water runoff from this facility to surface waters of the state is authorized under the Florida Storm Water Multi-Sector General Permit for Industrial Activities (MSGP), Permit Number FLR05G904-001 et seq.

C. Impoundment Operation and Maintenance

1. All impoundments (including percolation basins and dredge spoils areas) used to hold or treat wastewater and other associated wastes shall be operated and maintained to prevent the discharge of pollutants to waters of the State, except as authorized under this permit and MSGP Permit Number FLR05G904-001 et seq.

[4] Administrative Order AO-021-TL establishes an interim freeboard limitation of 1 foot, pursuant to the conditions of the order.

2. Operation and maintenance of any impoundment shall be in accordance with all applicable State regulations. When practicable, piezometers or other instrumentation shall be used as a means to aid monitoring of impoundment integrity.

D. Impoundment Integrity Inspections

1. No later than March 31, 2011, and annually thereafter, all impoundments shall be inspected by qualified personnel with knowledge and training in impoundment integrity. Annual inspections shall include observations of dike and toe areas for erosion, cracks or bulges, seepage, wet or soft soil, changes in geometry, the depth and elevation of the impounded water, sediment or slurry, freeboard, changes in vegetation such as overly lush, dead or unnaturally tilted vegetation, and any other changes which may indicate a potential compromise to impoundment integrity.

2. Within 30 days after the annual inspection, a qualified, responsible officer shall certify to the Department that no breaches or structural defects resulting in the discharges to surface waters of the State and that no changes were observed which may indicate a potential compromise to impoundment integrity during the previous calendar year.

   The certification shall also include a statement that the impoundments provides the necessary minimum wet weather detention volume to contain the combined volume for all direct rainfall and all rainfall runoff to the pond resulting from the 10-year, 24-hour rainfall event and maximum dry weather plant waste flows which could occur during a 24-hour period.

3. The permittee shall conduct follow-up inspections within 7 days after large or extended rain events (i.e., 25-year, 24-hour precipitation event).

4. In the event that the impoundment integrity is compromised and may result in a potential discharge to surfaces waters of the State, the permittee shall notify the Department within twenty-four (24) hours of becoming aware of the situation and provide a proposed course of corrective action and implementation schedule within fifteen (15) days after notifying the Department. Observed changes such as significant increases in seepage or seepage carrying sediment may be signs of imminent impoundment failure and should be addressed immediately.

E. Reporting and Recordkeeping Requirements for Impoundments

1. The summarized findings of all monitoring activities, inspections, and corrective actions pertaining to the impoundment integrity, and operation and maintenance of all impoundments shall be documented and kept on-site in accordance with Permit Condition V.A.2, and made available to Department inspectors upon request.

2. Starting with the issuance of this permit, all pertinent impoundment permits, design, construction, operation, and maintenance information, including but not limited to: plans, geotechnical and structural integrity studies, copies of permits, associated certifications by qualified, Florida-registered professional engineer, and regulatory approvals, shall be kept on site in accordance with Permit Condition V.A.2 and made available to Department inspectors upon request.

VI. SCHEDULES

1. The summarized findings of all monitoring activities, inspections, and corrective actions pertaining to the impoundment integrity, and operation and maintenance of all impoundments shall be documented and kept on-site in accordance with permit Condition V.A.2. and made available to Department inspectors upon request.

Improvement Action	Completion Date
1. BMP3 Progress/Update Reports	Issuance date of permit plus 1 year, and continuing annually
2. Continue implementing the existing BMP3 Plan	Issuance date of permit

[62-620.320(6)]

2. The following implementation steps shall be completed in accordance with the following schedule:

Implementation Steps		Scheduled Completion Date
1.	Permittee shall submit documentation for the location of the staff gauges in percolation basins to the Department's Southwest District Office.	Within 45 days from permit issuance
2.	Notify the Department when installation of the staff gauges is completed.	Within 30 days after installation
3.	Installation of proposed MWC-6 (MW-6) as required in Permit Condition III.B.1	Within 90 days from permit issuance
4.	Permittee shall notify Department's Southwest District Office that Army Corps of Engineers permit has been received.	Within 7 days after receiving the Army Corps of Engineers permit.
5.	Permittee shall complete the construction of the new dock in the discharge canal	Within 60 days after receiving the Army Corps of Engineers permit.
6.	Permittee shall commence monitoring at the new dock in the discharge canal for those parameters listed in Permit Condition I.A.1 with monitoring location EFF-1; and discontinue monitoring for those parameters at the once-through cooling water system condenser outlet	Within 30 days after completion of item 5 above.

3. Within six months of the effective date of this permit, the permittee shall schedule a meeting with the Department to discuss the contents of the aquatic organism return plan in accordance with Condition I.A.10 and shall submit the plan to the Department within 12 months of the effective date of this permit. The plan shall be implemented within 24 months subsequent to approval by the Department.

4. No later than 60 days after issuance of the permit, the permittee shall prepare and submit for the Department's review a plan of study with schedule for Phase II Monitoring for evaluation of the biological impact from the thermal plume at Paul L. Bartow Power Plant. The results of the Phase II evaluation shall be submitted in a report to the Department for review and approval no later than 180 days prior to the permit expiration date.

5. No later than 60 days after issuance of the permit, the Permittee shall prepare and submit for the Department's review an updated schedule for the approved dissolved oxygen plan of study at Paul L. Bartow Power Plant. The permittee shall conduct at least two years of monitoring during the months of May through September, which shall commence in May 2011. Annually, within 60 days of completing the monitoring for each year, the permittee shall submit a report summarizing the results.

6. In accordance with sections 403.088(2)(e) and (f), Florida Status (F.S.), a compliance schedule for this facility is contained in Administrative Order AO-021-TL which is hereby incorporated by reference.

7. No later than 14 calendar days following a date identified in the above schedule(s) of compliance, the Permittee shall submit either a report of progress or, in the case of specific actions being required by an identified date, a written notice of compliance or noncompliance. In the latter case, the notice shall include the cause of noncompliance, any remedial actions taken, and the probability of meeting the next scheduled requirement.

VII. BEST MANAGEMENT PRACTICES

1. General Conditions

In accordance with Section 304(e) and 402(a)(2) of the Clean Water Act (CWA) as amended, 33 U.S.C. §§ 1251 et seq., and the Pollution Prevention Act of 1990, 42 U.S.C. §§ 13101-13109, the permittee must develop and implement a plan for utilizing practices incorporating pollution prevention measures. References to be considered in developing the plan are "Criteria and Standards for Best Management Practices Authorized Under Section 304(e) of the Act," found at 40 CFR 122.44 Subpart K and the Storm Water Management Industrial Activities Guidance Manual, EPA/833-R92-002 and other EPA documents relating to Best Management Practice guidance.

a. Definitions

(1) The term "pollutants" refers to conventional, non-conventional and toxic pollutants.

(2) Conventional pollutants are: biochemical oxygen demand (BOD), suspended solids, pH, fecal coliform bacteria and oil & grease.

(3) Non-conventional pollutants are those which are not defined as conventional or toxic.

(4) Toxic pollutants include, but are not limited to: (a) any toxic substance listed in Section 307(a)(1) of the CWA, any hazardous substance listed in Section 311 of the CWA, or chemical listed in Section 313(c) of the Superfund Amendments and Reauthorization Act of 1986; and (b) any substance (that is not also a conventional or non-conventional pollutant except ammonia) for which EPA has published an acute or chronic toxicity criterion.

(5) "Significant Materials" is defined as raw materials; fuels; materials such as solvents and detergents; hazardous substances designated under Section 101(14) of CERCLA; and any chemical the facility is required to report pursuant to EPCRA, Section 313; fertilizers; pesticides; and waste products such as ashes, slag and sludge.

(6) "Pollution prevention" and "waste minimization" refer to the first two categories of EPA's preferred hazardous waste management strategy: first, source reduction and then, recycling.

(7) "Recycle/Reuse" is defined as the minimization of waste generation by recovering and reprocessing usable products that might otherwise become waste; or the reuse or reprocessing of usable waste products in place of the original stock, or for other purposes such as material recovery, material regeneration or energy production.

(8) "Source reduction" means any practice which: (a) reduces the amount of any pollutant entering a waste stream or otherwise released into the environment (including fugitive emissions) prior to recycling, treatment or disposal; and (b) reduces the hazards to public health and the environment associated with the release of such pollutant. The term includes equipment or technology modifications, process or procedure modifications, reformulation or redesign of products, substitution of raw materials, and improvements in housekeeping, maintenance, training, or inventory control. It does not include any practice which alters the physical, chemical, or biological characteristics or the volume of a pollutant through a process or activity which itself is not integral to, or previously considered necessary for, the production of a product or the providing of a service.

(9) "BMP3" means a Best Management Practices Pollution Prevention Plan incorporating the requirements of 40 CFR § 125, Subpart K, plus pollution prevention techniques, except where other existing programs are deemed equivalent by the permittee. The permittee shall certify the equivalency of the other referenced programs.

(10) The term "material" refers to chemicals or chemical products used in any plant operation (i.e., caustic soda, hydrazine, degreasing agents, paint solvents, etc.). It does not include lumber, boxes, packing materials, etc.

2. Best Management Practices/Pollution Prevention Plan

The permittee shall develop and implement a BMP3 plan for the facility, which is the source of wastewater and storm water discharges, covered by this permit. The plan shall be directed toward reducing those pollutants of concern which discharge to surface waters and shall be prepared in accordance with good engineering and good housekeeping practices. For the purposes of this permit, pollutants of concern shall be limited to toxic pollutants, as defined above, known to the discharger. The plan shall address all activities which could or do contribute these pollutants to the surface water discharge, including process, treatment, and ancillary activities.

a. Signatory Authority & Management Responsibilities

The BMP3 plan shall be signed by permittee or their duly authorized representative in accordance with rule 62-620.305(2)(a) and (b). The BMP3 plan shall be reviewed by plant environmental/engineering staff and plant manager. Where required by Chapter 471-(P.E.) or Chapter 492 (P.G.) Florida Statutes, applicable portions of the BMP3 plant shall be signed and sealed by the professional(s) who prepared them.

A copy of the plant shall be retained at the facility and shall be made available to the permit issuing authority upon request.

The BMP3 plan shall contain a written statement from corporate or plant management indicating management's commitment to the goals of the BMP3 program. Such statements shall be publicized or made known to all facility employees. Management shall also provide training for the individuals responsible for implementing the BMP3 plan.

b. BMP3 Plan Requirements

(1) Name & description of facility, a map illustrating the location of the facility & adjacent receiving waters, and other maps, plot plans or drawings, as necessary;
(2) Overall objectives (both short-term and long-term) and scope of the plan, specific reduction goals for pollutants, anticipated dates of achievement of reduction, and a description of means for achieving each reduction goal;
(3) A description of procedures relative to spill prevention, control & countermeasures and a description of measures employed to prevent storm water contamination;
(4) A description of practices involving preventive maintenance, housekeeping, recordkeeping, inspections, and plant security; and
(5) The description of a waste minimization assessment performed in accordance with the conditions outlined in condition c below, results of the assessment, and a schedule for implementation of specific waste reduction practices.

c. Waste Minimization Assessment

The permittee is encouraged but not required to conduct a waste minimization assessment (WMA) for this facility to determine actions that could be taken to reduce waste loading and chemical losses to all wastewater and/or storm water streams as described in this permit.

If the permittee elects to develop and implement a WMA, information on plan components can be obtained forms the Department's Industrial Wastewater website, or from:

Florida Department of Environmental Protection
Industrial Wastewater Section, Mail Station 3545
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
(850) 245-8589
(850) 245-8669 – Fax

d. Best Management Practices & Pollution Prevention Committee Recommended:

A Best Management Practices Committee (Committee) should be established to direct or assist in the implementation of the BMP3 plan. The Committee should be comprised of individuals within the plant organization who are responsible for developing the BMP3 plan and assisting the plant manager in its implementation, monitoring of success, and revision. The activities and responsibilities of the Committee should address all aspects of the facility's BMP3 plan. The scope of responsibilities of the Committee should be described in the plan.

e. Employee Training

Employee training programs shall inform personnel at all levels of responsibility of the components & goals of the BMP3 plan and shall describe employee responsibilities for implementing the plan. Training shall address topics such as good housekeeping, materials management, record keeping & reporting, spill prevention & response, as well as specific waste reduction practices to be employed. Training should also disclose how individual employees may contribute suggestions concerning the BMP3 plan or suggestions regarding Pollution Prevention. The plan shall identify periodic dates for such training.

f. Plan Development & Implementation

The BMP3 plan shall be developed and implemented 6 months after the effective date of this permit, unless any later dates are specified in this permit. Any portion of the WMA which is ongoing at the time of development or implementation shall be described in the plan. Any waste reduction practice which is recommended for implementation over a period of time shall be identified in the plan, including a schedule for its implementation.

g. Submission of Plan Summary & Progress/Update Reports

(1) Plan Summary: Not later than 2 years after the effective date of the permit, a summary of the BMP3 plan shall be developed and maintained at the facility and made available to the permit issuing authority upon request. The summary should include the following: a brief description of the plan, its implementation process, schedules for implementing identified waste reduction practices, and a list of all waste reduction

practices being employed at the facility. The results of waste minimization assessment studies already completed as well as any scheduled or ongoing WMA studies shall be discussed.

(2) Progress/Update Reports: Annually thereafter for the duration of the permit progress/update reports documenting implementation of the plan shall be maintained at the facility and made available to the permit issuing authority upon request. The reports shall discuss whether or not implementation schedules were met and revise any schedules, as necessary. The plan shall also be updated as necessary and the attainment or progress made toward specific pollutant reduction targets documented. Results of any ongoing WMA studies as well as any additional schedules for implementation of waste reduction practices shall be included.

(3) A timetable for the various plan requirements follows:

Timetable for BMP3 Plan Requirements:

REQUIREMENT	TIME FROM EFFECTIVE DATE OF THIS PERMIT
Progress/Update Reports	3 years, and then annually thereafter

The permittee shall maintain the plan and subsequent reports at the facility and shall make the plan available to the Department upon request.

h. Plan Review & Modification

If following review by the Department, the BMP3 plan is determined insufficient, the permittee will be notified that the BMP3 plan does not meet one or more of the minimum requirements of this Part. Upon such notification from the Department, the permittee shall amend the plan and shall submit to the Department a written certification that the requested changes have been made. Unless otherwise provided by the Department, the permittee shall have 30 days after such notification to make the changes necessary.

3. The permittee shall modify the BMP3 plan whenever there is a change in design, construction, operation, or maintenance, which has a significant effect on the potential for the discharge of pollutants to waters of the State or if the plan proves to be ineffective in achieving the general objectives of reducing pollutants in wastewater or storm water discharges. Modifications to the plan may be reviewed by the Department in the same manner as described above.

VIII. OTHER SPECIFIC CONDITIONS

A. General Operation and Maintenance Requirements

1. Where required by Chapter 471 or Chapter 492, F.S., applicable portions of reports that must be submitted under this permit shall be signed and sealed by a professional engineer or a professional geologist, as appropriate. *[62-620.310(4)]*

2. Drawings, plans, documents or specifications submitted by the permittee, not attached hereto, but retained on file at the Department's Southwest District Office, are made a part hereof.

3. This permit satisfies Industrial Wastewater program permitting requirements only and does not authorize operation of this facility prior to obtaining any other permits required by local, state or federal agencies.

4. The permittee shall provide verbal notice to the Department's Southwest District Office as soon as practical after discovery of a sinkhole or other karst feature within an area for the management or application of wastewater, or wastewater sludges. The permittee shall immediately implement measures appropriate to control the entry of contaminants, and shall detail these measures to the Department's Southwest District Office in a written report within 7 days of the sinkhole discovery. *[62-620.320(6)]*

B. Specific Conditions Related to Existing Manufacturing, Commercial, Mining, and Silviculture Wastewater Facilities or Activities

1. Existing manufacturing, commercial, mining, and silvicultural wastewater facilities or activities that discharge into surface waters shall notify the Department as soon as they know or have reason to believe:

a. That any activity has occurred or will occur which would result in the discharge, on a routine or frequent basis, of any toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following levels;
   (1) One hundred micrograms per liter,
   (2) Two hundred micrograms per liter for acrolein and acrylonitrile; five hundred micrograms per liter for 2, 4-dinitrophenol and for 2-methyl-4, 6-dinitrophenol; and one milligram per liter for antimony, or
   (3) Five times the maximum concentration value reported for that pollutant in the permit application; or

b. That any activity has occurred or will occur which would result in any discharge, on a non-routine or infrequent basis, of a toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following levels;
   (1) Five hundred micrograms per liter,
   (2) One milligram per liter for antimony, or
   (3) Ten times the maximum concentration value reported for that pollutant in the permit application.

[62-620.625(1)]

C. Duty to Reapply

1. The permittee is not authorized to discharge to waters of the State after the expiration date of this permit, unless:

   a. the permittee has applied for renewal of this permit at least 180 days before the expiration date (**August 7, 2015**) using the appropriate forms listed in Rule 62-620.910, F.A.C., and in the manner established in the Department of Environmental Protection Guide to Permitting Wastewater Facilities or Activities Under Chapter 62-620, F.A.C., including submittal of the appropriate processing fee set forth in Rule 62-4.050, F.A.C.; or

   b. the permittee has made complete the application for renewal of this permit before the permit expiration date.

2. When publishing Notice of Draft and Notice of Intent in accordance with Rules 62-110.106 and 62-620.550, F.A.C., the permittee shall publish the notice at its expense in a newspaper of general circulation in the county or counties in which the activity is to take place either:

   a. Within thirty days after the permittee has received a notice; or

   b. Within thirty days after final agency action.

   Failure to publish a notice is a violation of this permit.

D. Reopener Clauses

1. The permit shall be revised, or alternatively, revoked and reissued in accordance with the provisions contained in Rules 62-620.325 and 62-620.345 F.A.C., if applicable, or to comply with any applicable effluent standard or limitation issued or approved under Sections 301(b)(2)(C) and (D), 304(b)(2) and 307(a)(2) of the Clean Water Act (the Act), as amended, if the effluent standards, limitations, or water quality standards so issued or approved:

   a. Contains different conditions or is otherwise more stringent than any condition in the permit/or;

   b. Controls any pollutant not addressed in the permit.

   The permit as revised or reissued under this paragraph shall contain any other requirements then applicable.

2. The permit may be reopened to adjust effluent limitations or monitoring requirements should future Water Quality Based Effluent Limitation determinations, water quality studies, DEP approved changes in water quality standards, EPA established Total Maximum Daily Loads (TMDLs), or other information show a need for a different limitation or monitoring requirement.

3. The Department or EPA may develop a TMDL during the life of the permit. Once a TMDL has been established and adopted by rule, the Department shall revise this permit to incorporate the final findings of the TMDL.

4. The permit shall be reopened for revision as appropriate to address new information that was not available at the time of this permit issuance or to comply with requirements of new regulations, standards, or judicial decisions relating to CWA 316(b).

IX. GENERAL CONDITIONS

1. The terms, conditions, requirements, limitations and restrictions set forth in this permit are binding and enforceable pursuant to Chapter 403, Florida Statutes. Any permit noncompliance constitutes a violation of Chapter 403, Florida Statutes, and is grounds for enforcement action, permit termination, permit revocation and reissuance, or permit revision. *[62-620.610(1)]*

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications or conditions of this permit constitutes grounds for revocation and enforcement action by the Department. *[62-620.610(2)]*

3. As provided in Subsection 403.087(7), F.S., the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor authorize any infringement of federal, state, or local laws or regulations. This permit is not a waiver of or approval of any other Department permit or authorization that may be required for other aspects of the total project which are not addressed in this permit. *[62-620.610(3)]*

4. This permit conveys no title to land or water, does not constitute state recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title. *[62-620.610(4)]*

5. This permit does not relieve the permittee from liability and penalties for harm or injury to human health or welfare, animal or plant life, or property caused by the construction or operation of this permitted source; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department. The permittee shall take all reasonable steps to minimize or prevent any discharge, reuse of reclaimed water, or residuals use or disposal in violation of this permit which has a reasonable likelihood of adversely affecting human health or the environment. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. *[62-620.610(5)]*

6. If the permittee wishes to continue an activity regulated by this permit after its expiration date, the permittee shall apply for and obtain a new permit. *[62-620.610(6)]*

7. The permittee shall at all times properly operate and maintain the facility and systems of treatment and control, and related appurtenances, that are installed and used by the permittee to achieve compliance with the conditions of this permit. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to maintain or achieve compliance with the conditions of the permit. *[62-620.610(7)]*

8. This permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit revision, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance does not stay any permit condition. *[62-620.610(8)]*

9. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, including an authorized representative of the Department and authorized EPA personnel, when applicable, upon presentation of credentials or other documents as may be required by law, and at reasonable times, depending upon the nature of the concern being investigated, to:

   a. Enter upon the permittee's premises where a regulated facility, system, or activity is located or conducted, or where records shall be kept under the conditions of this permit;

b. Have access to and copy any records that shall be kept under the conditions of this permit;

c. Inspect the facilities, equipment, practices, or operations regulated or required under this permit; and

d. Sample or monitor any substances or parameters at any location necessary to assure compliance with this permit or Department rules.

[62-620.610(9)]

10. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data, and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except as such use is proscribed by Section 403.111, F.S., or Rule 62-620.302, F.A.C. Such evidence shall only be used to the extent that it is consistent with the Florida Rules of Civil Procedure and applicable evidentiary rules. *[62-620.610(10)]*

11. When requested by the Department, the permittee shall within a reasonable time provide any information required by law which is needed to determine whether there is cause for revising, revoking and reissuing, or terminating this permit, or to determine compliance with the permit. The permittee shall also provide to the Department upon request copies of records required by this permit to be kept. If the permittee becomes aware of relevant facts that were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be promptly submitted or corrections promptly reported to the Department. *[62-620.610(11)]*

12. Unless specifically stated otherwise in Department rules, the permittee, in accepting this permit, agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance; provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules. A reasonable time for compliance with a new or amended surface water quality standard, other than those standards addressed in Rule 62-302.500, F.A.C., shall include a reasonable time to obtain or be denied a mixing zone for the new or amended standard. *[62-620.610(12)]*

13. The permittee, in accepting this permit, agrees to pay the applicable regulatory program and surveillance fee in accordance with Rule 62-4.052, F.A.C. *[62-620.610(13)]*

14. This permit is transferable only upon Department approval in accordance with Rule 62-620.340, F.A.C. The permittee shall be liable for any noncompliance of the permitted activity until the transfer is approved by the Department. *[62-620.610(14)]*

15. The permittee shall give the Department written notice at least 60 days before inactivation or abandonment of a wastewater facility or activity and shall specify what steps will be taken to safeguard public health and safety during and following inactivation or abandonment. *[62-620.610(15)]*

16. The permittee shall apply for a revision to the Department permit in accordance with Rules 62-620.300, F.A.C., and the Department of Environmental Protection Guide to Permitting Wastewater Facilities or Activities Under Chapter 62-620, F.A.C., at least 90 days before construction of any planned substantial modifications to the permitted facility is to commence or with Rule 62-620.325(2), F.A.C., for minor modifications to the permitted facility. A revised permit shall be obtained before construction begins except as provided in Rule 62-620.300, F.A.C. *[62-620.610(16)]*

17. The permittee shall give advance notice to the Department of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements. The permittee shall be responsible for any and all damages which may result from the changes and may be subject to enforcement action by the Department for penalties or revocation of this permit. The notice shall include the following information:

a. A description of the anticipated noncompliance;

b. The period of the anticipated noncompliance, including dates and times; and

c. Steps being taken to prevent future occurrence of the noncompliance.

[62-620.610(17)]

18. Sampling and monitoring data shall be collected and analyzed in accordance with Rule 62-4.246 and Chapters 62-160, 62-601, and 62-610, F.A.C., and 40 CFR 136, as appropriate.

    a. Monitoring results shall be reported at the intervals specified elsewhere in this permit and shall be reported on a Discharge Monitoring Report (DMR), DEP Form 62-620.910(10), or as specified elsewhere in the permit.

    b. If the permittee monitors any contaminant more frequently than required by the permit, using Department approved test procedures, the results of this monitoring shall be included in the calculation and reporting of the data submitted in the DMR.

    c. Calculations for all limitations which require averaging of measurements shall use an arithmetic mean unless otherwise specified in this permit.

    d. Except as specifically provided in Rule 62-160.300, F.A.C., any laboratory test required by this permit shall be performed by a laboratory that has been certified by the Department of Health Environmental Laboratory Certification Program (DOH ELCP). Such certification shall be for the matrix, test method and analyte(s) being measured to comply with this permit. For domestic wastewater facilities, testing for parameters listed in Rule 62-160.300(4), F.A.C., shall be conducted under the direction of a certified operator.

    e. Field activities including on-site tests and sample collection shall follow the applicable standard operating procedures described in DEP-SOP-001/01 adopted by reference in Chapter 62-160, F.A.C.

    f. Alternate field procedures and laboratory methods may be used where they have been approved in accordance with Rules 62-160.220, and 62-160.330, F.A.C.

    [62-620.610(18)]

19. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule detailed elsewhere in this permit shall be submitted no later than 14 days following each schedule date. *[62-620.610(19)]*

20. The permittee shall report to the Department's Southwest District Office any noncompliance which may endanger health or the environment. Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided within five days of the time the permittee becomes aware of the circumstances. The written submission shall contain: a description of the noncompliance and its cause; the period of noncompliance including exact dates and time, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

    a. The following shall be included as information which must be reported within 24 hours under this condition:
        (1) Any unanticipated bypass which causes any reclaimed water or effluent to exceed any permit limitation or results in an unpermitted discharge,
        (2) Any upset which causes any reclaimed water or the effluent to exceed any limitation in the permit,
        (3) Violation of a maximum daily discharge limitation for any of the pollutants specifically listed in the permit for such notice, and
        (4) Any unauthorized discharge to surface or ground waters.

    b. Oral reports as required by this subsection shall be provided as follows:
        (1) For unauthorized releases or spills of treated or untreated wastewater reported pursuant to subparagraph 20(a).4. that are in excess of 1,000 gallons per incident, or where information indicates that public health or the environment will be endangered, oral reports shall be provided to the STATE WARNING POINT TOLL FREE NUMBER (800) 320-0519, as soon as practical, but no later than 24 hours from the time the permittee becomes aware of the discharge. The permittee, to the extent known, shall provide the following information to the State Warning Point:
            (a) Name, address, and telephone number of person reporting;
            (b) Name, address, and telephone number of permittee or responsible person for the discharge;
            (c) Date and time of the discharge and status of discharge (ongoing or ceased);
            (d) Characteristics of the wastewater spilled or released (untreated or treated, industrial or domestic wastewater);
            (e) Estimated amount of the discharge;
            (f) Location or address of the discharge;
            (g) Source and cause of the discharge;

(h) Whether the discharge was contained on-site, and cleanup actions taken to date;
(i) Description of area affected by the discharge, including name of water body affected, if any; and
(j) Other persons or agencies contacted.

(2) Oral reports, not otherwise required to be provided pursuant to subparagraph 20.b.1 above, shall be provided to the Department's Southwest District Office within 24 hours from the time the permittee becomes aware of the circumstances.

c. If the oral report has been received within 24 hours, the noncompliance has been corrected, and the noncompliance did not endanger health or the environment, the Department's Southwest District Office shall waive the written report.

[62-620.610(20)]

21. The permittee shall report all instances of noncompliance not reported under Permit Conditions IX. 17, 18 or 19 of this permit at the time monitoring reports are submitted. This report shall contain the same information required by Permit Condition IX.20 of this permit. *[62-620.610(21)]*

22. Bypass Provisions.

a. "Bypass" means the intentional diversion of waste streams from any portion of a treatment works.

b. Bypass is prohibited, and the Department may take enforcement action against a permittee for bypass, unless the permittee affirmatively demonstrates that:

(1) Bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and
(2) There were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if adequate back-up equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass which occurred during normal periods of equipment downtime or preventive maintenance; and
(3) The permittee submitted notices as required under Permit Condition VIII.22.b. of this permit.

c. If the permittee knows in advance of the need for a bypass, it shall submit prior notice to the Department, if possible at least 10 days before the date of the bypass. The permittee shall submit notice of an unanticipated bypass within 24 hours of learning about the bypass as required in Permit Condition VIII.20. of this permit. A notice shall include a description of the bypass and its cause; the period of the bypass, including exact dates and times; if the bypass has not been corrected, the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence of the bypass.

d. The Department shall approve an anticipated bypass, after considering its adverse effect, if the permittee demonstrates that it will meet the three conditions listed in Permit Condition IX. 22.b.1 through 3 of this permit.

e. A permittee may allow any bypass to occur which does not cause reclaimed water or effluent limitations to be exceeded if it is for essential maintenance to assure efficient operation. These bypasses are not subject to the provisions of Permit Condition IX.22.b. through d. of this permit.

[62-620.610(22)]

23. Upset Provisions.

a. "Upset" means an exceptional incident in which there is unintentional and temporary noncompliance with technology-based effluent limitations because of factors beyond the reasonable control of the permittee.

(1) An upset does not include noncompliance caused by operational error, improperly designed treatment facilities, inadequate treatment facilities, lack of preventive maintenance, careless or improper operation.
(2) An upset constitutes an affirmative defense to an action brought for noncompliance with technology based permit effluent limitations if the requirements of upset provisions of Rule 62-620.610, F.A.C., are met.

b. A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed contemporaneous operating logs, or other relevant evidence that:

(1) An upset occurred and that the permittee can identify the cause(s) of the upset;
(2) The permitted facility was at the time being properly operated;
(3) The permittee submitted notice of the upset as required in Permit Condition IX.5. of this permit; and
(4) The permittee complied with any remedial measures required under Permit Condition IX.5. of this permit.

))

c. In any enforcement proceeding, the burden of proof for establishing the occurrence of an upset rests with the permittee.

d. Before an enforcement proceeding is instituted, no representation made during the Department review of a claim that noncompliance was caused by an upset is final agency action subject to judicial review.

[62-620.610(23)]

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENTOF
ENVIRONMENTAL PROTECTION

Director
Division of Water Resource Management
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
(850) 245-8336

Attachment(s):
Administrative Order
Discharge Monitoring Report

BEFORE THE STATE OF FLORIDA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

IN THE MATTER OF:

Progress Energy Florida, Inc.
1601 Weedon Island Drive
St. Petersburg, Florida 33702

Administrative Order No. AO021TL

Paul L. Bartow Power Plant
DEP Permit No: FL0000132

ADMINISTRATIVE ORDER

I. STATUTORY AUTHORITY

The Department of Environmental Protection (Department) issues this Administrative Order under the authority of Section 403.088(2)(f), Florida Statutes (F.S.). The Secretary of the Department has delegated this authority to the Director of the Division of Water Resources Management, who issues this order and makes the following findings of fact.

II. FINDINGS OF FACT

1. Progress Energy Florida (PEF or Permittee) is a "person" as defined under Section 403.031(5), F.S.
2. The Permittee owns and operates a steam electric power generating facility known as Paul L. Bartow power plant ("Facility"). The Facility, located at 1601 Weedon Island Drive, St. Petersburg Pinellas County, Florida 33702, discharges industrial wastewater into waters of the state as defined in Section 403.031(13), F.S.
3. The Permittee has filed a timely application for renewal of NPDES Permit No. FL0000132 (Permit), under Section 403.088(2), F.S.
4. In June 2009, the Permittee began commercial operation of its repowered Facility. The repowered Facility directs all process wastewater, except once-through cooling water which is non-process wastewater, into the existing onsite percolation pond system. On average, flows range from 20 to 250 gallons per minute, depending on facility operations and demineralized water needs.
5. In December 2009, the Permittee notified the Department that the percolation ponds were not operating as originally designed. The contents of the percolation ponds were pumped into the dredge spoil pond to the east of the percolation ponds. A total of 8,316,000 gallons of water was transferred into the dredge spoil pond December 11-16, 2009.
6. Sections 403.088(2)(e) and (f), F.S., allow the Department to issue a permit for the discharge of wastewater into waters of the state, which may not immediately meet all applicable rule requirements, if the permit is accompanied by an order establishing a schedule for achieving compliance with all permit conditions if criteria specified in the order are met.
7. The Department finds that the granting of an operation permit will be in the public interest; and,
8. This order and associated wastewater Permit FL0000132 constitute the Department's authorization to discharge pollutants to waters of the state under the NPDES and state groundwater program, and its determination that the Facility is in compliance with Section 403.088, F.S. This order includes an implementation schedule.

III. ORDER

Based on the foregoing findings of fact,

IT IS ORDERED,

9. The Permittee shall comply with the freeboard limitations in Part IV. of the Permit no later than 30 months from the issuance date of this Order.

10. Until compliance with the freeboard limitations in Part IV. of the Permit is achieved as required in paragraph III.9. of this Order, the Permittee shall comply with an interim limit of 1 foot.

11. When a freeboard of less than 3 feet exists in the percolation pond, the Permittee may transfer water from the percolation basins to the on-site dredge spoil area, contingent upon the following requirements being met:

    a. The freeboard in the dredge spoil ponds is maintained at a level of 3 feet or more and
    b. The depth of water in the dredge spoil ponds is maintained at a level less than that in the percolation ponds.

    The permittee shall notify the Department's Southwest District Office prior to commencement of a water transfer from the percolation ponds to the dredge spoil ponds.

12. The Permittee shall not discharge from the percolation pond or the dredge pond to surface waters of the State.

13. No later than 30 days after the effective date of this Order, the Permittee shall prepare and submit for the Department's review a Plan of Study (POS) and schedule for the evaluation of the percolation ponds. The POS shall be designed and implemented to demonstrate whether the percolation ponds at the Facility meet the freeboard limitations in Part IV. of the Permit. The results of the evaluation shall be submitted in a report (Report) to the Department for review and approval no later than 60 days after the approved POS completion date.

14. If the Report demonstrates that the percolation ponds at the Facility are unable to meet the freeboard limitations in Part IV. of the Permit, the Permittee shall prepare a feasibility study report (Report) for engineering options to achieve the freeboard limitation. The options shall be ranked based on equal weighting of technical and economic feasibility and environmental impact. In addition, the Report shall include a plan and schedule for implementing the highest ranked option. The schedule shall include milestones and the completion date.

    The Report shall be submitted to the Department for review and approval no later than 60 days after the approved POS completion date.

15. The Permittee shall provide a status report demonstrating progress toward compliance with the freeboard limitation every three months following the effective date of this Order, until compliance is achieved pursuant to paragraph III.9 of this Order. The status reports shall document accomplishment of milestones established by the schedule in the approved POS and Report.

18. Monitoring results shall be submitted in accordance with the Permit.

19. The Permittee shall maintain and operate its facilities in compliance with all other conditions of the Permit.

20. This order may be modified through revisions as set forth in Chapter 62-620, F.A.C.

21. Unless otherwise specified herein, reports or other information required by this order shall be sent to: Industrial Wastewater Section, ATTN: Mail Station 3545, Department of Environmental Protection,

2600 Blair Stone Road, Tallahassee, Florida 32399-2400, with a copy sent to: Industrial Wastewater Section, Department of Environmental Protection, Southwest District, 13501 N. Telecom Parkway, Temple Terrace, Florida 33637.

22. This order does not operate as a permit under Section 403.088, F.S. This order shall be incorporated by reference into NPDES Permit No. FL0000132, which shall require compliance by the Permittee with the requirements of this order.

23. Failure to comply with the requirements of this order shall constitute a violation of this order and Permit No. FL0000132, and may subject the Permittee to penalties as provided in Section 403.161, F.S.

24. This order is final when filed with the clerk of the Department, and the Permittee then shall implement this order unless a petition for an administrative proceeding (hearing) is filed in accordance with the notice set forth in the following Section.

25. If any event occurs that causes delay or the reasonable likelihood of delay, in complying with the requirements of this order, the Permittee shall have the burden of demonstrating that the delay was or will be caused by circumstances beyond the reasonable control of the Permittee and could not have been or cannot be overcome by the Permittee's due diligence. Economic circumstances shall not be considered circumstances beyond the reasonable control of the Permittee, nor shall the failure of a contractor, subcontractor, materialman or other agent (collectively referred to as "contractor") to whom responsibility for performance is delegated to meet contractually imposed deadlines be a cause beyond the control of the Permittee, unless the cause of the contractor's late performance was also beyond the contractor's control. Delays in final agency action on an application for a relief mechanism are eligible for consideration under this paragraph, provided that none of those delays were a result of late submission by the Permittee. Upon occurrence of an event causing delay, or upon becoming aware of a potential for delay, the Permittee shall notify the Department orally at: the Department's Southwest District office, (813) 632-7600, within 24 hours or by the next working day and shall, within seven calendar days of oral notification to the Department, notify the Department in writing at: Southwest District office, 13501 N. Telecom Parkway, Temple Terrace, Florida 33637 of the anticipated length and cause of the delay, the measures taken or to be taken to prevent or minimize the delay and the timetable by which Facility intends to implement these measures. If the delay or anticipated delay has been or will be caused by circumstances beyond the reasonable control of the Permittee, the time for performance hereunder shall be extended for a period equal to the delay resulting from such circumstances.

IV. NOTICE OF RIGHTS

A person whose substantial interests are affected by the Department's decision may petition for an administrative proceeding (hearing) under Sections 120.569 and 120.57 of the F.S. The petition must contain the information set forth below and must be filed (received by the clerk) in the Office of General Counsel of the Department at 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000.

Petitions by the applicant or any of the parties listed below must be filed within twenty-one days of receipt of this written notice. Petitions filed by any persons other than those entitled to written notice under Section 120.60(3), F.S., must be filed within twenty-one days of publication of the notice or within twenty-one days of receipt of the written notice, whichever occurs first.

Under Section 120.60(3), F.S., however, any person who has asked the Department for notice of agency action may file a petition within twenty-one days of receipt of such notice, regardless of the date of publication.

The petitioner shall mail a copy of the petition to the applicant at the address indicated above at the time of filing. The failure of any person to file a petition within the appropriate time period shall constitute a waiver of that person's right to request an administrative determination (hearing) under Sections 120.569 and 120.57, F.S. Any subsequent intervention (in a proceeding initiated by another party) will be only at the discretion of the presiding officer upon the filing of a motion in compliance with Rule 28-106.205, F.A.C.

A petition that disputes the material facts on which the Department's action is based must contain the following information:

(a) The name, address, and telephone number of each petitioner; the Department permit identification number and the county in which the subject matter or activity is located;

(b) A statement of how and when each petitioner received notice of the Department action;

(c) A statement of how each petitioner's substantial interests are affected by the Department action;

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

(e) A statement of facts that the petitioner contends warrant reversal or modification of the Department action;

(f) A statement of which rules or statutes the petitioner contends require reversal or modification of the Department action; and

(g) A statement of the relief sought by the petitioner, stating precisely the action that the petitioner wants the Department to take.

A petition that does not dispute the material facts on which the Department's action is based shall state that no such facts are in dispute and otherwise shall contain the same information as set forth above, as required by Rule 28-106.301, F.A.C.

Because the administrative hearing process is designed to formulate final agency action, the filing of a petition means that the Department's final action may be different from the position taken by it in this notice. Persons whose substantial interests will be affected by any such final decision of the Department have the right to petition to become a party to the proceeding, in accordance with the requirements set forth above.

Mediation under Section 120.573, F.S., is not available for this proceeding.

This action is final and effective on the date filed with the Clerk of the Department unless a petition is filed in accordance with the above. Upon the timely filing of a petition this order will not be effective until further order of the Department.

Any party to the order has the right to seek judicial review of the order under Section 120.68, F.S., by the filing of a notice of appeal under rule 9.110 of the Florida Rules of Appellate Procedure with the Clerk of the Department in the Office of General Counsel, Mail Station 35, 3900 Commonwealth Boulevard, Tallahassee, Florida, 32399-3000; and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate district court of appeal. The notice of appeal must be filed within 30 days from the date when the final order is filed with the Clerk of the Department.

DONE AND ORDERED on this 2nd day of February 2011 in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT OF ENVIRONMENTAL PROTECTION

Director
Division of Water Resource Management

CLERK STAMP

FILED AND ACKNOWLEDGED on this date, under Section 120.52(7) of the Florida Statutes, with the designated Department Clerk, receipt of which is acknowledged.

Shirley Shields
Clerk

02-07-11
Date

Copies furnished to Permit Distribution List

))

Florida Department of Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

NOTICE OF PERMIT

RECEIVED
JAN 19 2011
Environmental Services

CERTIFIED MAIL

In the Matter of an
Application for Permit by:

Progress Energy Florida, Inc.
Anclote Power Plant
1729 Baillies Bluff Road
Holiday, FL 34691-9753

DEP File # FL0002992-010-IW1S/NR
Pasco County

Attention: Reginald D. Anderson, Plant Manager

Enclosed is Permit Number FL0002992 to Progress Energy Florida, Inc., Post Office Box 14042, St. Petersburg, FL 33733 to operate wastewater treatment and effluent disposal facilities for Units 1 and 2 of the Anclote Power Plant located at 1729 Baillies Bluff Road in Holiday, Florida 34691, issued under Section 403.0885, Florida Statutes and DEP Rule 62-620, Florida Administrative Code.

Any party to this order (permit) has the right to seek judicial review of the permit under Section 120.68, Florida Statutes, by the filing of a Notice of Appeal under Rules 9.110 and 9.190, Florida Rules of Appellate Procedure, with the Clerk of the Department of Environmental Protection, Office of General Counsel, Mail Station 35, 3900 Commonwealth Boulevard, Tallahassee, Florida 32399-3000 and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate district court of appeal. The notice of appeal must be filed within thirty days after this notice is filed with the clerk of the Department.

Executed in Talllahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Janet G. Llewellyn

Janet G. Llewellyn
Division Director
Division of Water Resource Management
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Docket No. 110007-EI
Progress Energy Florida
Witness: Patricia Q. West
Exhibit No.__(PQW-1)
Page 46 of 85

EXHIBIT B

Anlcote Power Plant
Facility ID Number FL0002992

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this NOTICE OF PERMIT and all copies were mailed before the close of business on 01-14-2011 to the listed persons.

[Clerk Stamp]

FILING AND ACKNOWLEDGMENT

FILED, on this date, under Section 120.52 (9), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Shirley Shields 01-14-2011
(Clerk) (Date)

Copies furnished by certified mail to:
Mark Nuhfer, NPDES Permitting Section, EPA Region 4, Atlanta, GA
Chairman, Board of Pasco County Commissioners

Copies furnished by First Class mail to:
Patricia Garner, Progress Energy Florida
Ron Mezich, Florida Fish and Wildlife Conservation Commission (FW C)
U.S. Fish & Wildlife Services

Copies furnished by intradepartmental mail to:
Justin Wolfe, Esq., DEP Tallahassee
Yanisa Angulo, DEP Tampa
Ilia Balcom, DEP Tampa

SECOND AMENDMENT TO THE FACT SHEET

Date: January 5, 2011

Application No.: FL0002992-IW1S

Permittee: Progress Energy Florida, Inc.
Anclote Power Plant

The following changes are based on comments from the Permittee in an email to the Department dated January 4, 2011 and previous comments on the draft permit in a letter to the Department dated August 3, 2010. They are intended to correct minor errors in the Proposed Permit, and make non-substantive changes in certain permit conditions as requested by the permitte and as outline below:

Condition VI.4, Page 13: The due date for the *Phase I Final Report* was changed from December 31, 2012 to December 31, 2011.

Table I.B.9, Page 10: The requirement for monitoring and reporting oil & grease was removed from the stormwater Outfall D-006 monitoring table. Oil & grease monitoring at Outfall D-006 was not included in the previous permit. Oil & grease was added to the draft renewal permit at the request of the DEP Southwest District office. The facility has pointed out that the current sampling at Outfall D-006 uses an automatic composite sampler that cannot be used to take a grab sample for oil and grease. Outfall D-006 analytical data submitted as part of the permit renewal application indicated an oil & grease level below detection (<1.4 mg/l) and below the State water quality standard of 5.0 mg/l. The DEP Southwest District office as indicated that it has no objection to removing the oil & grease monitoring requirement from the renewal permit.

Condition I.B.7, page 9: The facility has requested that the first paragraph of Condition I.B.7 be deleted since sampling and monitoring requirements included in this paragraph are already addressed in General Condition 18 of the permit. The first paragraph of Condition I.B.7 defines what in meant by Total Residual Oxidants (TRO) and specifies allowable analytical testing requirements for TRO. General Condition 18 specifies that sampling and monitoring data shall be collected and analyzed in accordance with Rule 62-4.246 and Chapters 62-160, 62-601, and 62-610, F.A.C., and 40 CFR 136, as appropriate.

The Department concurs with the facility that the TRO testing requirements in the first paragraph of Condition I.B.7 are already covered under General Condition 18. All the requirements for analyzing TRO that are outlined in the first paragraph of Condition I.B.7 are contained in 40 CFR 136. Additional testing requirements are included in appropriate Department laboratory quality assurance SOP's as required in DEP Rule 62-160.

Based on the above the first paragraph of Condition I.B.7 has been removed and replaced with the following wording: "Total Residual Oxidants (TRO) means the value obtained using testing procedures for Total Residual Chlorine (TRC) found in 40 CFR 136.3."

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Florida Department of Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Rick Scott
Governor

Jennifer Carroll
Lt. Governor

Mimi A. Drew
Secretary

STATE OF FLORIDA
INDUSTRIAL WASTEWATER FACILITY PERMIT

PERMITTEE:
Progress Energy Florida, Inc.

PERMIT NUMBER: FL0002992(Major)
FILE NUMBER: FL0002992-010-IW1S
ISSUANCE DATE: January 14, 2011
EXPIRATION DATE: January 13, 2016

RESPONSIBLE OFFICIAL:
Reginald D. Anderson
1729 Baillies Bluff Road
Holiday, Florida 34691

RECEIVED
JAN 19 2011
Environmental Services

FACILITY:

Progress Energy Florida, Inc.
Anclote Power Plant
1729 Baillies Bluff Rd
Holiday, FL 34691-9753
Pasco County
Latitude: 28°11' 1.27" N Longitude: 82°47' 6.29" W

This permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and applicable rules of the Florida Administrative Code (F.A.C.) and constitutes authorization to discharge to waters of the state under the National Pollutant Discharge Elimination System. This permit does not constitute authorization to discharge wastewater other than as expressly stated in this permit. The above named permittee is hereby authorized to operate the facilities in accordance with the documents attached hereto and specifically described as follows:

FACILITY DESCRIPTION:

The plant consists of two oil-fired steam electric units with a total nameplate rating of 1,112 MW. Once-through condenser cooling water from Units 1 and 2 is passed through bar racks and intake screens, pumped through the condensers to remove excessive heat, and discharged to the plant's discharge canal. Normal debris, such as seagrass, is collected by the raker system and by the travelling screens and sluiced to the discharge canal. Larger debris collected from the intake, such as logs and limbs, is disposed of by landfill and wash water is returned to the plant discharge canal. During certain times of the year, two non-recirculating cooling towers are operated to reduce the plant discharge temperature. The cooling towers receive a portion of the heated water from the condensers where water is cooled and then discharged to the discharge canal. In-line, self cleaning debris filters remove grass and debris from the water prior to the entering cooling tower distribution system. Back flush water used to clean the debris filters is directed to the cooling tower basin where it is recombined with the cooling water that passes through the cooling tower. A biocide is added to the cooling tower intake water for biofouling control and then dehalogenated, if necessary, prior to discharge. In addition, there are four dilution pumps which help provide temperature control by pumping additional water from the intake canal to the discharge canal.

WASTEWATER TREATMENT:

All other wastewater generated at this plant is discharged into two on-site percolation/evaporation ponds, without surface water discharge. The discharge to the percolation/evaporation ponds is authorized by separate permit issued by the Department's Southwest District.

REUSE OR DISPOSAL:

Surface Water Discharge D-004: An existing discharge to Anclote Sound (Gulf of Mexico), Class III Marine Waters, (WBID# 8045C). The point of discharge is located approximately at latitude 28°11' 22" N, longitude 82°47' 13" W.

Internal Outfall I-001: An existing discharge of once-through condenser cooling water from Unit 1 to the discharge canal.

Internal Outfall I-002: An existing discharge of once-through condenser cooling water from Unit2 to the discharge canal.

Internal Outfall I-003: An existing discharge of once-through dilution water flow from the intake canal to the discharge canal.

Internal Outfall I-005: An existing discharge of cooling tower discharge to the discharge canal.

Stormwater Outfall: An existing internal discharge of stormwater via Outfall I-006 to the intake canal.

IN ACCORDANCE WITH: The limitations, monitoring requirements and other conditions set forth in this Cover Sheet and Part I through Part IX on pages 1 through 25 of this permit.

PERMITTEE: Progress Energy Florida, Inc
FACILITY: Anclote Power Plant

PERMIT NUMBER: FL0002992 (Major)
ISSUANCE DATE: January 14, 2011
EXPIRATION DATE: January 13, 2016

I. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

A. *Surface Water Discharges*

1. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge combined plant discharge from Outfall D-004 to Anclote Sound (Gulf of Mexico). Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.C.3.:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Intake Temperature, Water	Deg F	Max Max Max	Report Report Report	1 Hour Average 3 Hour Average Daily Average	Continuous	Recorder	INT-1	
[illegible]								
Discharge Temperature (Primary)	Deg F	Max Max Max	90.0 92.0 Report	1 Hour Average Instantaneous Maximum Daily Average	Continuous	Recorder	EFF-1	
Temperature Rise (Primary)	Deg F	Max Max	Report Report	1 Hour Average Daily Average	Continuous	Recorder	EFF-1	
Discharge Temperature (Alternate)[1]	Deg F	Max Max Max Max	92.0 95.0 95.5 Report	Daily Average 1 Hour Average Instantaneous Maximum 3 Hour Average	Continuous	Recorder	EFF-1	
Temperature Rise (Alternate)[1]	Deg F	Max Max Max	5.0 Report Report	3 Hour Average 1 Hour Average Daily Average	Continuous	Recorder	EFF-1	
Mode II [illegible]								
Discharge Temperature (Primary)	Deg F	Max Max Max	92.0 95.0 Report	1 Hour Average Instantaneous Maximum Daily Average	Continuous	Recorder	EFF-1	
Temperature Rise (Primary)	Deg F	Max Max	Report Report	1 Hour Average Daily Average	Continuous	Recorder	EFF-1	
Discharge Temperature (Alternate)[2]	Deg F	Max Max Max Max	92.0 95.0 95.5 Report	Daily Average 1 Hour Average Instantaneous Maximum 3 Hour Average	Continuous	Recorder	EFF-1	

[1] Mode I temperature limitations are applicable each year beginning on January 1 and lasting until the daily average intake temperature first equals or exceeds 82.0°F in the Spring. Additionally, Mode I limitations are applicable beginning the day after the daily average intake temperature falls below 82.0°F in the fall and lasting through December 31.

[2] Alternate monitoring and limitations are applicable only when the facility is unable to meet primary limitations with three cooling tower pumps and 22 cooling tower fans in operation. If alternate mode thresholds are met and there occurs a non-availability of the minimum number of cooling tower fans and pumps due to equipment malfunction, the permittee may remain in alternate mode. In such case, the permittee shall endeavor to repair or take other necessary measures to return the inoperable fan(s) or pump(s) back into service as soon as possible.

[3] Mode II temperature limitations are applicable each year beginning the day after the daily average intake temperature first equals or exceeds 82.0 °F and lasting through the day on which the daily average temperature first falls below 82.0°F in the Fall.

Parameter	Units	Max/Min	Effluent Limitations: Limit	Effluent Limitations: Statistical Basis	Monitoring Requirements: Frequency of Analysis	Monitoring Requirements: Sample Type	Monitoring Requirements: Monitoring Site Number	Notes
Temperature rise (Alternate)[2]	Deg F	Max Max Max	5.0 Report Report	3 Hour Average 1 Hour Average Daily Average	Continuous	Recorder	EFF-1	
Temperature, Water	Deg C	Max Max	Report Report	Single Sample Single Sample	Quarterly	Grab	EFF-1 INT-1	See I.A.4
pH	su	Max Max	Report Report	Single Sample Single Sample	Quarterly	Grab	EFF-1 INT-1	See I.A.4
Nitrogen, Ammonia, Total (as N)	mg/L	Max Max	Report Report	Single Sample Single Sample	Quarterly	Grab	EFF-1 INT-1	See I.A.4
Ammonia, Total Unionized (as NH_3)	mg/L	Max Max	Report Report	Single Sample Single Sample	Quarterly	Calculated	EFF-1 INT-1	See I.A.4
Nitrogen, Kjeldahl, Total (as N)	mg/L	Max Max	Report Report	Single Sample Single Sample	Quarterly	Grab	EFF-1 INT-1	
Nitrite plus Nitrate, Total 1 det. (as N)	mg/L	Max Max	Report Report	Single Sample Single Sample	Quarterly	Grab	EFF-1 INT-1	
Nitrogen, Total	mg/L	Max Max	Report Report	Single Sample Single Sample	Quarterly	Grab	EFF-1 INT-1	
Phosphorus, Total (as P)	mg/L	Max Max	Report Report	Single Sample Single Sample	Quarterly	Grab	EFF-1 INT-1	
Phosphate, Ortho (as PO4)	mg/L	Max Max	Report Report	Single Sample Single Sample	Quarterly	Grab	EFF-1 INT-1	
Chronic Whole Effluent Toxicity, 7-Day IC25 (Mysidopsis bahia)	percent	Min	100	Single Sample	Quarterly	24-hr TPC	EFF-1	See I.A.5
Chronic Whole Effluent Toxicity, 7-Day IC25 (Menidia beryllina)	percent	Min	100	Single Sample	Quarterly	24-hr TPC	EFF-1	See I.A.5

2. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.A.1. and as described below:

Monitoring Site Number	Description of Monitoring Site
INT-1	Condenser intake waterboxes for Units 1 & 2.
EFF-1	At the combined plant Point of Discharge (POD) at the end of the discharge canal.

3. Any combination of dilution pumps and cooling tower equipment may be operated to achieve the above Mode I and Mode II limitations; however, the facility shall operate the dilution pumps as the primary means of achieving thermal limitations. In the event that excessive amounts of seagrass and/or debris is being drawn into the plant intake canal; dilution pumps use may be discontinued so as to prevent equipment damage as necessary.

Operation of cooling tower pumps and fans shall be minimized to the extent possible in order to meet thermal limitations. However, operation of one dilution pump minimum is required at all times when cooling towers are being operated except in the case of mechanical or electrical failure or in the event that the intake water to the dilution pumps exceeds the discharge temperature from the cooling towers.

4. Samples for pH and temperature (grab) shall be taken simultaneously with each total ammonia grab sample. Un-ionized ammonia shall be calculated in accordance with the procedure provided by the Department (refer to the website www.dep.state.fl.us./labs/library/index.htm). All measured values for pH, temperature, and total ammonia used to calculate an un-ionized ammonia value shall be reported as an attachment to the Discharge Monitoring Report (DMR). All calculated un-ionized ammonia values shall be reported on the attachment. The daily maximum and monthly average values for un-ionized ammonia for each reporting period shall be reported on the DMR.

5. The permittee shall comply with the following requirements to evaluate chronic whole effluent toxicity of the discharge from outfall D-004.

   a. Effluent Limitation
      (1) In any routine or additional follow-up test for chronic whole effluent toxicity, the 25 percent inhibition concentration (IC25) shall not be less than 100% effluent. [Rules 62-302.530(61) and 62-4.241(1)(b), F.A.C.]
      (2) For acute whole effluent toxicity, the 96-hour LC50 shall not be less than 100% effluent in any test. [Rules 62-302.500(1)(a)4. and 62-4.241(1)(a), F.A.C.]

   b. Monitoring Frequency
      (1) Routine toxicity tests shall be conducted once every three months, the first starting within 60 days of the issuance date of this permit and lasting for the duration of this permit.
      (2) Upon completion of four consecutive, valid routine tests that demonstrate compliance with the effluent limitation in 5.a.(1) above, the permittee may submit a written request to the Department for a reduction in monitoring frequency to once every six months. The request shall include a summary of the data and the complete bioassay laboratory reports for each test used to demonstrate compliance. The Department shall act on the request within 45 days of receipt. Reductions in monitoring shall only become effective upon the Department's written confirmation that the facility has completed four consecutive valid routine tests that demonstrate compliance with the effluent limitation in 5.a.(1) above.
      (3) If a test within the sequence of the four is deemed invalid based on the acceptance criteria in EPA-821-R-02-014, but is replaced by a repeat valid test initiated within 21 days after the last day of the invalid test, the invalid test will not be counted against the requirement for four consecutive valid tests for the purpose of evaluating the reduction of monitoring frequency.

   c. Sampling Requirements
      (1) For each routine test or additional follow-up test conducted, a total of three 24-hour composite samples of final effluent shall be collected and used in accordance with the sampling protocol discussed in EPA-821-R-02-014, Section 8.
      (2) The first sample shall be used to initiate the test. The remaining two samples shall be collected according to the protocol and used as renewal solutions on Day 3 (48 hours) and Day 5 (96 hours) of the test.
      (3) Samples for routine and additional follow-up tests shall not be collected on the same day.

   d. Test Requirements
      (1) Routine Tests: All routine tests shall be conducted using a control (0% effluent) and a minimum of five test dilutions: 100%, 50%, 25%, 12.5%, and 6.25% final effluent.
      (2) The permittee shall conduct 7-day survival and growth chronic toxicity tests with a mysid shrimp, **Americamysis (Mysidopsis) bahia**, Method 1007.0, and an inland silverside, **Menidia beryllina**, Method 1006.0, concurrently.
      (3) All test species, procedures and quality assurance criteria used shall be in accordance with <u>Short-term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Marine and Estuarine Organisms</u>, 3rd Edition, EPA-821-R-02-014. Any deviation of the bioassay procedures outlined herein shall be submitted in writing to the Department for review and approval prior to use. In the event the above method is revised, the permittee shall conduct chronic toxicity testing in accordance with the revised method.
      (4) The control water and dilution water used shall be artificial sea salts as described in EPA-821-R-02-014, Section 7.2. The test salinity shall be determined as follows:

(a) For the **Americamysis bahia** bioassays, the effluent shall be adjusted to a salinity of 20 parts per thousand (ppt) with artificial sea salts. The salinity of the control/dilution water (0% effluent) shall be 20 ppt. If the salinity of the effluent is greater than 20 ppt, no salinity adjustment shall be made to the effluent and the test shall be run at the effluent salinity. The salinity of the control/dilution water shall match the salinity of the effluent.

(b) For the **Menidia beryllina** bioassays, if the effluent salinity is less than 5ppt, the salinity shall be adjusted to 5 ppt with artificial sea salts. The salinity of the control/dilution water (0% effluent) shall be 5 ppt. If the salinity of the effluent is greater than 5 ppt, no salinity adjustment shall be made to the effluent and the test shall be run at the effluent salinity. The salinity of the control/dilution water shall match the salinity of the effluent.

(c) If the salinity of the effluent requires adjustment, a salinity adjustment control should be prepared and included with each bioassay. The salinity adjustment control is intended to identify toxicity resulting from adjusting the effluent salinity with artificial sea salts. To prepare the salinity adjustment control, dilute the control/dilution water to the salinity of the effluent and adjust the salinity of the salinity adjustment control at the same time and to the same salinity that the salinity of the effluent is adjusted using the same artificial sea salts.

e. Quality Assurance Requirements

(1) A standard reference toxicant (SRT) quality assurance (QA) chronic toxicity test shall be conducted with each species used in the required toxicity tests either concurrently or initiated no more than 30 days before the date of each routine or additional follow-up test conducted. Additionally, the SRT test must be conducted concurrently if the test organisms are obtained from outside the test laboratory unless the test organism supplier provides control chart data from at least the last five monthly chronic toxicity tests using the same reference toxicant and test conditions. If the organism supplier provides the required SRT data, the organism supplier's SRT data and the test laboratory's monthly SRT-QA data shall be included in the reports for each companion routine or additional follow-up test required.

(2) If the mortality in the control (0% effluent) exceeds 20% for either species in any test or any test does not meet "test acceptability criteria", the test for that species (including the control) shall be invalidated and the test repeated. Test acceptability criteria for each species are defined in EPA-821-R-02-014, Section 14.12 (**Americamysis bahia**) and Section 13.12 (**Menidia beryllina**). The repeat test shall begin within 21 days after the last day of the invalid test.

(3) If 100% mortality occurs in all effluent concentrations for either species prior to the end of any test and the control mortality is less than 20% at that time, the test (including the control) for that species shall be terminated with the conclusion that the test fails and constitutes non-compliance.

(4) Routine and additional follow-up tests shall be evaluated for acceptability based on the observed dose-response relationship as required by EPA-821-R-02-014, Section 10.2.6., and the evaluation shall be included with the bioassay laboratory reports.

f. Reporting Requirements

(1) Results from all required tests shall be reported on the Discharge Monitoring Report (DMR) as follows:
 (a) Routine and Additional Follow-up Test Results: The calculated IC25 for each test species shall be entered on the DMR.

(2) A bioassay laboratory report for each routine test shall be prepared according to EPA-821-R-02-014, Section 10, Report Preparation and Test Review, and mailed to the Department at the address below within 30 days after the last day of the test.

(3) For additional follow-up tests, a single bioassay laboratory report shall be prepared according to EPA-821-R-02-014, Section 10, and mailed within 30 days after the last day of the second valid additional follow-up test.

(4) Data for invalid tests shall be included in the bioassay laboratory report for the repeat test.

(5) The same bioassay data shall not be reported as the results of more than one test.

(6) All bioassay laboratory reports shall be sent to:
Florida Department of Environmental Protection
Tallahassee Office
2600 Blair Stone Road, M.S. 3545
Tallahassee, Florida 32399-2400

g. Test Failures
   (1) A test fails when the test results do not meet the limits in 5.a.(1).
   (2) Additional Follow-up Tests:
      (a) If a routine test does not meet the chronic toxicity limitation in 5.a.(1) above, the permittee shall notify the Department at the address above within 21 days after the last day of the failed routine test and conduct two additional follow-up tests on each species that failed the test in accordance with 5.d.
      (b) The first test shall be initiated within 28 days after the last day of the failed routine test. The remaining additional follow-up tests shall be conducted weekly thereafter until a total of two valid additional follow-up tests are completed.
      (c) The first additional follow-up test shall be conducted using a control (0% effluent) and a minimum of five dilutions: 100%, 50%, 25%, 12.5%, and 6.25% effluent. The permittee may modify the dilution series in the second additional follow-up test to more accurately bracket the toxicity such that at least two dilutions above and two dilutions below the target concentration and a control (0% effluent) are run. All test results shall be analyzed according to the procedures in EPA-821-R-02-014.
   (3) In the event of three valid test failures (whether routine or additional follow-up tests) within a 12-month period, the permittee shall notify the Department within 21 days after the last day of the third test failure.
      (a) The permittee shall submit a plan for correction of the effluent toxicity within 60 days after the last day of the third test failure.
      (b) The Department shall review and approve the plan before initiation.
      (c) The plan shall be initiated within 30 days following the Department's written approval of the plan.
      (d) Progress reports shall be submitted quarterly to the Department at the address above.
      (e) During the implementation of the plan, the permittee shall conduct quarterly routine whole effluent toxicity tests in accordance with 5.d. Additional follow-up tests are not required while the plan is in progress. Following completion or termination of the plan, the frequency of monitoring for routine and additional follow-up tests shall return to the schedule established in 5.b.(1). If a routine test is invalid according to the acceptance criteria in EPA-821-R-02-014, a repeat test shall be initiated within 21 days after the last day of the invalid routine test.
      (f) Upon completion of four consecutive quarterly valid routine tests that demonstrate compliance with the effluent limitation in 5.a.(1) above, the permittee may submit a written request to the Department to terminate the plan. The plan shall be terminated upon written verification by the Department that the facility has passed at least four consecutive quarterly valid routine whole effluent toxicity tests. If a test within the sequence of the four is deemed invalid, but is replaced by a repeat valid test initiated within 21 days after the last day of the invalid test, the invalid test will not be counted against the requirement for four consecutive quarterly valid routine tests for the purpose of terminating the plan.
   (4) If chronic toxicity test results indicate greater than 50% mortality within 96 hours in an effluent concentration equal to or less than the effluent concentration specified as the acute toxicity limit in 5.(a)(2), the Department may revise this permit to require acute definitive whole effluent toxicity testing.
   (5) The additional follow-up testing and the plan do not preclude the Department taking enforcement action for acute or chronic whole effluent toxicity failures.

[62-4.241, 62-620.620(3)]

6. The discharge shall not contain components that settle to form putrescent deposits or float as debris, scum, oil, or other matter. *[62-302.500(1)(a)]*

7. The permittee shall maintain current intake traveling screen practices so as to assure that the screens are cycled at least once per day or at least twice during a 24 hour period of circulating water pump operation unless precluded by repair or maintenance requirements.

8. The intake through-screen velocity shall be maintained at current levels such that existing maximum velocity is not exceeded.

9. The permittee shall develop a plan in accordance with the schedule in Condition VI.3 to return live fish, shellfish, and other aquatic organisms collected or trapped on the intake screens to their natural habitat. Other material shall be removed from the intake screens and disposed of in accordance with all existing Federal, State and /or local laws and regulations that apply to waste disposal. Such material shall not be returned to the receiving waters.

B. Internal Outfalls

1. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge once-through non-contact cooling water from I-001 and I-002 from Unit 1 and 2, respectively, to the discharge canal. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.C.3.:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow (Total Units 1 and 2 OTCW)	MGD	Max	Report	Daily Average	Daily	Pump Logs	FLW-1	

2. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.1. and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-1	Units 1 and 2 OTCW flow measurement location.

3. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge once-through dilution water from I-003 to the discharge canal. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.C.3.:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max	Report	Daily Average	Daily	Pump Logs	FLW-2	
Duration of Discharge	hours/month	Max	Report	Daily Average	Daily	Pump Logs	FLW-2	

4. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.3. and as described below:

Monitoring Site Number	Description of Monitoring Site

Monitoring Site Number	Description of Monitoring Site
FLW-2	dilution pump flow measurement location

5. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge cooling tower blowdown from I-005 to discharge canal. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.C.3.:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
TRO-Discharge Time[4]	min/tower/day	Max	120	Instantaneous Maximum	Daily	Calculated	EFF-2	
Dosage Rate[5]	lbs/tower/day	Max	500	Instantaneous Maximum	Daily	Calculated	INT-2	
Oxidants, Total Residual	mg/L	Max	0.01	Instantaneous Maximum	Weekly	Grab[6]	EFF-1	
Oxidants, Total Residual	mg/L	Min	0.05	Instantaneous Minimum	Weekly	Meter	EFF-2	

6. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.5. and as described below:

Monitoring Site Number	Description of Monitoring Site
EFF-2	At the point where the cooling tower discharge enters the discharge canal and prior to mixing with the receiving water.
EFF-1	At the combined plant Point of Discharge (POD) at the end of the discharge canal.
INT-2	At the point of addition.

7. Total Residual Oxidants (TRO) means the value obtain using testing procedures for Total Residual Chlorine (TRC) found in 40 CFR 136.3.

   Monitoring requirements for TRO are not applicable if an oxidant has not been added to the cooling towers of any electric generating unit during the previous 7 days.

   Multiple grabs for TRO shall be defined as once per five minutes during TRO discharge periods of 30 minutes or less and once per 15 minutes for periods exceeding 30 minutes with no less than four analyses during the period of TRO discharge (sampling shall be continued until the end of the TRO discharge).

[4] Not more than one cooling tower shall discharge TRO at any one time.

[5] The limitation is for pounds of available chlorine contained in liquid sodium hypochlorite currently being used by the facility. The facility is authorized to use liquid sodium bromide in conjunction with sodium hypochlorite at a feed rate based on a ratio of 2 moles of sodium hypochlorite to one mole of sodium bromide. Sodium bisulfite is used as needed for dehalogenation in order to meet TRO limitations.

[6] Multiple grabs for TRC shall consist of grab samples collected at approximately the beginning, middle, and end of the period of expected TRO discharge to the sampling point. Monitoring at EFF-1 is required only if the discharge TRO concentration at EFF-2 exceeds 0.01 mg/l

8. The permitee shall ensure that both cooling towers are maintained in good working order and available for operation when needed.

9. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge stormwater from I-006 to intake canal.. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.C.3.:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max	Report	Daily Maximum	Monthly, when discharging	Calculated	EFF-3	
Copper, Total Recoverable	ug/L	Max	Report	Daily Maximum	Monthly, when discharging	Grab	EFF-3	
Iron, Total Recoverable	ug/L	Max	Report	Daily Maximum	Monthly, when discharging	Grab	EFF-3	

10. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.9. and as described below:

Monitoring Site Number	Description of Monitoring Site
EFF-3	Prior to discharge to the intake canal or mixing with any other waste stream at sampling location previously identified as "stormdrain AN1"

C. Other Limitations and Monitoring and Reporting Requirements

1. The sample collection, analytical test methods, and method detection limits (MDLs) applicable to this permit shall be conducted using a sufficiently sensitive method to ensure compliance with applicable water quality standards and effluent limitations and shall be in accordance with Rule 62-4.246, Chapters 62-160 and 62-601, F.A.C., and 40 CFR 136, as appropriate. The list of Department established analytical methods, and corresponding MDLs (method detection limits) and PQLs (practical quantitation limits), which is titled "FAC 62-4 MDL/PQL Table (April 26, 2006)" is available at http://www.dep.state.fl.us/labs/library/index.htm. The MDLs and PQLs as described in this list shall constitute the minimum acceptable MDL/PQL values and the Department shall not accept results for which the laboratory's MDLs or PQLs are greater than those described above unless alternate MDLs and/or PQLs have been specifically approved by the Department for this permit. Any method included in the list may be used for reporting as long as it meets the following requirements:

   a. The laboratory's reported MDL and PQL values for the particular method must be equal or less than the corresponding method values specified in the Department's approved MDL and PQL list;

   b. The laboratory reported MDL for the specific parameter is less than or equal to the permit limit or the applicable water quality criteria, if any, stated in Chapter 62-302, F.A.C. Parameters that are listed as "report only" in the permit shall use methods that provide an MDL, which is equal to or less than the applicable water quality criteria stated in 62-302, F.A.C.; and

   c. If the MDLs for all methods available in the approved list are above the stated permit limit or applicable water quality criteria for that parameter, then the method with the lowest stated MDL shall be used.

When the analytical results are below method detection or practical quantitation limits, the permittee shall report the actual laboratory MDL and/or PQL values for the analyses that were performed following the instructions on the applicable *discharge monitoring report*.

Where necessary, the permittee may request approval of alternate methods or for alternative MDLs or PQLs for any approved analytical method. Approval of alternate laboratory MDLs or PQLs are not necessary if the laboratory reported MDLs and PQLs are less than or equal to the permit limit or the applicable water quality criteria, if any, stated in Chapter 62-302, F.A.C. Approval of an analytical method not included in the above-referenced list is not necessary if the analytical method is approved in accordance with 40 CFR 136 or deemed acceptable by the Department. *[62-4.246, 62-160]*

2. The permittee shall provide safe access points for obtaining representative influent and effluent samples which are required by this permit. *[62-620.320(6)]*

3. Monitoring requirements under this permit are effective on the first day of the second month following permit issuance. Until such time, the permittee shall continue to monitor and report in accordance with previously effective permit requirements, if any. During the period of operation authorized by this permit, the permittee shall complete and submit to the Department Discharge Monitoring Reports (DMRs) in accordance with the frequencies specified by the REPORT type (i.e. monthly, toxicity, quarterly, semiannual, annual, etc.) indicated on the DMR forms attached to this permit. Monitoring results for each monitoring period shall be submitted in accordance with the associated DMR due dates below.

REPORT Type on DMR	Monitoring Period	Due Date
Monthly or Toxicity	first day of month - last day of month	28th day of following month
Quarterly	January 1 - March 31 April 1 - June 30 July 1 - September 30 October 1 - December 31	April 28 July 28 October 28 January 28
Semiannual	January 1 - June 30 July 1 - December 30	July 28 January 28
Annual	January 1 - December 31	January 28

DMRs shall be submitted for each required monitoring period including months of no discharge. The permittee may submit either paper or electronic DMR form(s). If submitting paper DMR form(s), the permittee shall make copies of the attached DMR form(s). If submitting electronic DMR form(s), the permittee shall use a Department-approved electronic DMR system.

The electronic submission of DMR forms shall be accepted only if approved in writing by the Department. For purposes of determining compliance with this permit, data submitted in electronic format is legally equivalent to data submitted on signed and certified paper DMR forms.

The permittee shall submit the completed DMR form(s) to the Department by the twenty-eighth (28th) of the month following the month of operation at the addresses specified below:

Florida Department of Environmental Protection
Wastewater Compliance Evaluation Section, Mail Station 3551
Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

And

Florida Department of Environmental Protection
Southwest District

13051 N. Telecom Parkway
Temple Terrace, Florida 33637

[62-620.610(18)]

4. The permittee shall not submit DMR forms that alter the original format or content of the attached DMR forms without written approval from the Department's Southwest District Office at the address specified below:

   Florida Department of Environmental Protection
   Southwest District
   13051 N. Telecom Parkway
   Temple Terrace, Florida 33637

5. Unless specified otherwise in this permit, all reports and other information required by this permit, including 24-hour notifications, shall be submitted to or reported to, as appropriate, the Department's Southeast District Office at the address specified above.

6. All reports and other information shall be signed in accordance with the requirements of Rule 62-620.305, F.A.C. *[62-620.305]*

7. If there is no discharge from the facility on a day when the facility would normally sample, the sample shall be collected on the day of the next discharge. *[62-620.320(6)]*

8. The permittee shall notify the Department in writing no later than six (6) months prior to instituting use of any biocide or chemical (except sodium hypochlorite, sodium bromide, and sodium bisulfite) used in the cooling systems or any other portion of the treatment system which may be toxic to aquatic life. Such notification shall include:

   a. Name and general composition of biocide or chemical
   b. Frequencies of use
   c. Quantities to be used
   d. Proposed effluent concentrations
   e. Acute and/or chronic toxicity data (laboratory reports shall be prepared according to Section 12 of EPA document no. EPA/600/4-90/027 entitled, Methods for Measuring the Acute Toxicity of Effluents and Receiving Waters for Freshwater and Marine Organisms, or most current addition.)
   f. Product data sheet
   g. Product label

9. The Department will review the above information to determine if a major or minor permit revision is necessary. Discharge associated with the use of such biocide or chemical is not authorized without a permit revision by the Department. Permit revisions shall be processed in accordance with the requirements of Chapter 62-620, F.A.C.

10. The Permittee shall continue compliance with the facility's Manatee Protection Plan approved by the Department on May 13, 2002.

11. The permittee is authorized to discharge seal water used for lubrication of the cooling tower pump bearings to the discharge canal without limitations or monitoring requirements.

II. SLUDGE MANAGEMENT REQUIREMENTS

1. The method of sludge disposal by this facility is to a Class I solid waste landfill.

2. The permittee shall be responsible for proper treatment, management, use, and land application or disposal of its sludges. *[62-620.320(6)]*

3. Storage, transportation, and disposal of sludge/solids characterized as hazardous waste shall be in accordance with requirements of Chapter 62-730, F.A.C. *[62-730]*

III. GROUND WATER REQUIREMENTS

Section III is not applicable to this facility.

IV. ADDITIONAL LAND APPLICATION REQUIREMENTS

Section IV is not applicable to this facility.

V. OPERATION AND MAINTENANCE REQUIREMENTS

1. During the period of operation authorized by this permit, the wastewater facilities shall be operated under the supervision of a person who is qualified by formal training and/or practical experience in the field of water pollution control. *[62-620.320(6)]*

2. The permittee shall maintain the following records and make them available for inspection on the site of the permitted facility.

   a. Records of all compliance monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, including, if applicable, a copy of the laboratory certification showing the certification number of the laboratory, for at least three years from the date the sample or measurement was taken;

   b. Copies of all reports required by the permit for at least three years from the date the report was prepared;

   c. Records of all data, including reports and documents, used to complete the application for the permit for at least three years from the date the application was filed;

   d. A copy of the current permit;

   e. A copy of any required record drawings; and

   f. Copies of the logs and schedules showing plant operations and equipment maintenance for three years from the date of the logs or schedules.

   [62-620.350]

VI. SCHEDULES

1. The following improvement actions shall be completed according to the following schedule. The Best Management Practices/Pollution Prevention (BMP3) Plan shall be prepared and implemented in accordance with Part VII of this permit.

Improvement Action	Completion Date
1. Develop and implement SWPPP	18 months from permit issuance
2. Complete Plan Summary	2 years from permit issuance
3. Progress/Update Report	3 years, and then annual thereafter

[62-620.320(6)]

2. If the permittee wishes to continue operation of this wastewater facility after the expiration date of this permit, the permittee shall submit an application for renewal no later than one-hundred and eighty days (180) prior to the expiration date of this permit. Application shall be made using the appropriate forms listed in Rule 62-620.910, F.A.C., including submittal of the appropriate processing fee set forth in Rule 62-4.050, F.A.C. *[62-620.335(1) and (2)]*

3. Within 6 months from the issuance date of this permit, the permittee shall schedule a meeting with the Department to discuss the contents of the aquatic organism return plan in accordance with Condition I.A.9 and shall submit the plan to the Department within 12 months thereafter. The plan shall be implemented within 24 months subsequent to approval by the Department.

4. The permittee shall conduct a Thermal Plume Biological Assessment in accordance with the Plan of Study (POS) For A Thermal Plume Assessment dated September 2007 previously submitted to the Department and in accordance with the following schedule:

Phase I (Thermal Plum Delineation) .... May 2011 through September 2011
Phase I Final Report .... No later than December 31, 2011
Submit Phase II POS (Biological Assessment) .... No later than January 31, 2012
Begin Phase II .... May 2012
Phase II Final Report .... No later than 180 days Prior to Permit Expiration

VII. BEST MANAGEMENT PRACTICES/STORMWATER POLLUTION PREVENTION PLANS

1. General Requirements

In accordance with Section 304(e) and 402(a)(2) of the Clean Water Act (CWA) as amended, 33 U.S.C. §§ 1251 et seq., and the Pollution Prevention Act of 1990, 42 U.S.C. §§ 13101-13109, the permittee must develop and implement a plan for utilizing practices incorporating pollution prevention measures. References to be considered in developing the plan are "Criteria and Standards for Best Management Practices Authorized Under Section 304(e) of the Act," found at 40 CFR 122.44 Subpart K and the Storm Water Management Industrial Activities Guidance Manual, EPA/833-R92-002 and other EPA documents relating to Best Management Practice guidance.

a. Definitions

(1) The term "pollutants" refers to conventional, non-conventional and toxic pollutants.

(2) Conventional pollutants are: biochemical oxygen demand (BOD), suspended solids, pH, fecal coliform bacteria and oil & grease.

(3) Non-conventional pollutants are those which are not defined as conventional or toxic.

(4) Toxic pollutants include, but are not limited to: (a) any toxic substance listed in Section 307(a)(1) of the CWA, any hazardous substance listed in Section 311 of the CWA, or chemical listed in Section 313(c) of the Superfund Amendments and Reauthorization Act of 1986; and (b) any substance (that is not also a conventional or non-conventional pollutant except ammonia) for which EPA has published an acute or chronic toxicity criterion.

(5) "Significant Materials" is defined as raw materials; fuels; materials such as solvents and detergents; hazardous substances designated under Section 101(14) of CERCLA; and any chemical the facility is required to report pursuant to EPCRA, Section 313; fertilizers; pesticides; and waste products such as ashes, slag and sludge.

(6) "Pollution prevention" and "waste minimization" refer to the first two categories of EPA's preferred hazardous waste management strategy: first, source reduction and then, recycling.

(7) "Recycle/Reuse" is defined as the minimization of waste generation by recovering and reprocessing usable products that might otherwise become waste; or the reuse or reprocessing of usable waste products in place of the original stock, or for other purposes such as material recovery, material regeneration or energy production.

(8) "Source reduction" means any practice which: (a) reduces the amount of any pollutant entering a waste stream or otherwise released into the environment (including fugitive emissions) prior to recycling, treatment or disposal; and (b) reduces the hazards to public health and the environment associated with the release of such pollutant. The term includes equipment or technology modifications, process or

procedure modifications, reformulation or redesign of products, substitution of raw materials, and improvements in housekeeping, maintenance, training, or inventory control. It does not include any practice which alters the physical, chemical, or biological characteristics or the volume of a pollutant through a process or activity which itself is not integral to, or previously considered necessary for, the production of a product or the providing of a service.

(9) "SWPPP" means a Storm Water Pollution Prevention Plan incorporating the requirements of 40 CFR § 125, Subpart K, plus pollution prevention techniques, except where other existing programs are deemed equivalent by the permittee. The permittee shall certify the equivalency of the other referenced programs.

(10) The term "material" refers to chemicals or chemical products used in any plant operation (i.e., caustic soda, hydrazine, degreasing agents, paint solvents, etc.). It does not include lumber, boxes, packing materials, etc.

(11) The term "allowable non-storm water discharges" refers to the following discharges that may be discharged through storm water outfalls unless identified by the Department as sources of pollutants:

- Discharges from fire-fighting activities;
- Fire hydrant flushings;
- Potable water, including water line flushings;
- Uncontaminated condensate from air conditioners, coolers, and other compressors and from the outside storage of refrigerated gases or liquids;
- Irrigation drainage;
- Landscape watering provided all pesticides, herbicides, and fertilizer have been applied in accordance with the approved labeling;
- Pavement wash waters where no detergents are used and no spills or leaks of toxic or hazardous materials have occurred (unless all spilled material has been removed);
- Routine external building washdown that does not use detergents;
- Uncontaminated ground water or spring water;
- Foundation or footing drains where flows are not contaminated with process materials; and
- Incidental windblown mist from cooling towers that collects on rooftops or adjacent portions of your facility, but not intentional discharges from the cooling tower (e.g., "piped" cooling tower blowdown or drains).

2. Storm Water Pollution Prevention Plan

The permittee shall develop and implement a SWPPP for the facility, which is the source of wastewater and storm water discharges, covered by this permit. The plan shall be directed toward reducing those pollutants of concern which discharge to surface waters and shall be prepared in accordance with good engineering and good housekeeping practices. For the purposes of this permit, pollutants of concern shall be limited to toxic pollutants, as defined above, known to the discharger. The plan shall address all activities which could or do contribute these pollutants to the surface water discharge, including process, treatment, and ancillary activities.

a. Signatory Authority & Management Responsibilities

The SWPPP shall be signed by permittee or their duly authorized representative in accordance with rule 62-620.305(2)(a) and (b). The SWPPP shall be reviewed by plant environmental/engineering staff and plant manager. Where required by Chapter 471-(P.E.) or Chapter 492 (P.G.) Florida Statutes, applicable portions of the SWPPP shall be signed and sealed by the professional(s) who prepared them.

A copy of the plan shall be retained at the facility and shall be made available to the permit issuing authority upon request.

The SWPPP shall contain a written statement from corporate or plant management indicating management's commitment to the goals of the BMP program. Such statements shall be publicized or made known to all facility employees. Management shall also provide training for the individuals responsible for implementing the SWPPP.

b. SWPPP Requirements

(1) A topographic map extending one-quarter mile beyond the property boundaries of the facility, showing: the facility, surface water bodies, wells (including injection wells), seepage pits, infiltration ponds, and the discharge points where the facility's storm water discharges to a municipal storm drain system or other water body. The requirements of this paragraph may be included on the site map if appropriate.

(2) A site map showing:
  (a) The storm water conveyance and discharge structures;
  (b) An outline of the storm water drainage areas for each storm water discharge point;
  (c) Paved areas and buildings;
  (d) Areas used for outdoor manufacturing, storage, or disposal of significant materials, including activities that generate significant quantities of dust or particulates;
  (e) Location of existing or future storm water structural control measures/practices (dikes, coverings, detention facilities, etc.);
  (f) Surface water locations and/or municipal storm drain locations;
  (g) Areas of existing and potential soil erosion;
  (h) Vehicle service areas;
  (i) Material loading, unloading, and access areas;

(3) A narrative description of the following:
  (a) The nature of the industrial activities conducted at the site, including a description of significant materials that are treated, stored or disposed of in a manner to allow exposure to storm water;
  (b) Materials, equipment, and vehicle management practices employed to minimize contact of significant materials with storm water discharges;
  (c) Existing or future structural and non-structural control measures/practices to reduce pollutants in storm water discharges;
  (d) Industrial storm water discharge treatment facilities;
  (e) Methods of onsite storage and disposal of significant materials;
  (f) Overall objectives (both short-term and long-term) and scope of the plan, specific reduction goals for pollutants, anticipated dates of achievement of reduction, and a description of means for achieving each reduction goal;
  (g) A description of procedures relative to spill prevention, control & countermeasures and a description of measures employed to prevent storm water contamination;
  (h) A description of practices involving preventive maintenance, housekeeping, recordkeeping, inspections, and plant security; and
  (i) The description of a waste minimization assessment performed in accordance with the conditions outlined in condition c below, results of the assessment, and a schedule for implementation of specific waste reduction practices.

(4) A list of the allowable non-storm water discharges that have a reasonable potential to be present in storm water discharges at this facility.

(5) A list of the types of pollutants that have a reasonable potential to be present in storm water discharges in significant quantities.

(6) An estimate of the size of the facility in acres or square feet, and the percent of the facility that has impervious areas such as pavement or buildings.

(7) A summary of existing sampling data describing pollutants in storm water discharges.

c. Waste Minimization Assessment

The permittee is encouraged but not required to conduct a waste minimization assessment (WMA) for this facility to determine actions that could be taken to reduce waste loading and chemical losses to all wastewater and/or storm water streams as described in Part VII.D.2 of this permit.

If the permittee elects to develop and implement a WMA, information on plan components can be obtained forms the Department's Industrial Wastewater website, or from:

Florida Department of Environmental Protection
Industrial Wastewater Section, Mail Station 3545
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
(850) 245-8589
(850) 245-8669 – Fax

d. Pollution Prevention Committee:

A pollution prevention committee within the plant organization shall be appointed. These members shall be responsible for developing the SWPPP and assisting the plant manager in its implementation, maintenance, and revision.

e. Employee Training

(1) The permittee shall describe the storm water employee training program for the facility. The description shall include the topics to be covered, such as spill response, good housekeeping and material management practices, and shall identify periodic dates (e.g., every 6 months during the months of July and January) for such training. The permittee shall provide employee training for all employees and contractors that work in areas where industrial materials or activities are exposed to storm water, and for employees that are responsible for implementing activities identified in the SWPPP (e.g., inspectors, maintenance people). The employee training shall inform facility personnel and contractors of the components and goals of the facility SWPPP.

(2) Each employee and contractor that works in an areas where industrial materials or activities are exposed to storm water, and each employee that is responsible for implementing activities identified in the SWPPP shall undergo training at least once a year. Training records shall include trainee's name, signature, date of training and topics covered. Records shall be retained on-site for a minimum of three years.

f. Plan Development & Implementation

(1) The SWPPP shall be developed and implemented 18 months after the effective date of this permit, unless any later dates are specified in this permit. Any portion of the SWPPP which is ongoing at the time of development or implementation shall be described in the plan. Any waste reduction practice which is recommended for implementation over a period of time shall be identified in the plan, including a schedule for its implementation.

(2) The personnel named in the SWPPP shall perform and document a quarterly visual observation of a storm water discharge associated with industrial activity from each outfall. The visual observation shall be made during daylight hours. If no storm event resulted in runoff during daylight hours from the facility during a monitoring quarter, the permittee is excused from the visual observation requirement for that quarter, provided the permittee documents in their records that no runoff occurred. The permittee shall sign and certify the documentation.

(3) The personnel named in the SWPPP shall conduct visual observations on samples collected as soon as practical, but not to exceed 1 hour of when the runoff begins discharging from the facility. All samples must be collected from a storm event discharge that is greater than 0.1 inch in magnitude and that occurs at least 72 hours from the previously measurable (greater than 0.1 inch rainfall) storm event. The observation shall document: color, odor, clarity, floating solids, settled solids, suspended solids, foam, oil sheen, and other obvious indicators of storm water pollution.

(4) The permittee shall maintain visual observation reports onsite with the SWPPP for a minimum of three years. The report must include the observation date and time, inspection personnel, nature of the

discharge (i.e., runoff), visual quality of the storm water discharge (including observations of color, odor, clarity, floating solids, settled solids, suspended solids, foam, oil sheen, and other obvious indicators of storm water pollution), and probable sources of any observed storm water contamination.

(5) At least once a year the personnel named in the SWPPP shall verify that the description of potential pollutant sources required under this permit is accurate; the site map as required in the SWPPP has been updated or otherwise modified to reflect current conditions; and the controls to reduce pollutants in storm water discharges associated with industrial activity identified in the SWPPP are being implemented and are adequate.

g. Submission of Plan Summary & Progress/Update Reports

(1) Plan Summary: Not later than 2 years after the effective date of the permit, a summary of the SWPPP shall be developed and maintained at the facility and made available to the permit issuing authority upon request. The summary should include the following: a brief description of the plan, its implementation process, schedules for implementing identified waste reduction practices, and a list of all waste reduction practices being employed at the facility. The results of waste minimization assessment studies already completed as well as any scheduled or ongoing WMA studies shall be discussed.

(2) Progress/Update Reports: Annually thereafter for the duration of the permit progress/update reports documenting implementation of the plan shall be maintained at the facility and made available to the permit issuing authority upon request. The reports shall discuss whether or not implementation schedules were met and revise any schedules, as necessary. The plan shall also be updated as necessary and the attainment or progress made toward specific pollutant reduction targets documented. Results of any ongoing WMA studies as well as any additional schedules for implementation of waste reduction practices shall be included.

(3) A timetable for the various plan requirements follows:

Timetable for SWPPP Requirements:

REQUIREMENT	TIME FROM EFFECTIVE DATE OF THIS PERMIT
Complete SWPPP	18 months
Complete Plan Summary	2 years
Progress/Update Reports	3 years, and then annually thereafter

The permittee shall maintain the plan and subsequent reports at the facility and shall make the plan available to the Department upon request.

h. Plan Review & Modification

If following review by the Department, the SWPPP is determined insufficient, the permittee will be notified that the SWPPP does not meet one or more of the minimum requirements of this Part. Upon such notification from the Department, the permittee shall amend the plan and shall submit to the Department a written certification that the requested changes have been made. Unless otherwise provided by the Department, the permittee shall have 30 days after such notification to make the changes necessary.

The permittee shall modify the SWPPP whenever there is a change in design, construction, operation, or maintenance, which has a significant effect on the potential for the discharge of pollutants to waters of the State or if the plan proves to be ineffective in achieving the general objectives of reducing pollutants in wastewater or storm water discharges. Modifications to the plan may be reviewed by the Department in the same manner as described above.

The permittee may incorporate applicable portions of plans prepared for other purposes. Plans or portions of plans incorporated into a SWPPP become enforceable requirements of this permit.

VIII. OTHER SPECIFIC CONDITIONS

A. Specific Conditions Applicable to All Permits

1. Where required by Chapter 471 or Chapter 492, F.S., applicable portions of reports that must be submitted under this permit shall be signed and sealed by a professional engineer or a professional geologist, as appropriate. *[62-620.310(4)]*

2. Drawings, plans, documents or specifications submitted by the permittee, not attached hereto, but retained on file at the Department's Southwest District Office, are made a part hereof.

3. This permit satisfies Industrial Wastewater program permitting requirements only and does not authorize operation of this facility prior to obtaining any other permits required by local, state or federal agencies.

4. The permittee shall provide verbal notice to the Department's Southwest District Office as soon as practical after discovery of a sinkhole or other karst feature within an area for the management or application of wastewater, or wastewater sludges. The Permittee shall immediately implement measures appropriate to control the entry of contaminants, and shall detail these measures to the Department's Southwest District Office in a written report within 7 days of the sinkhole discovery. *[62-620.320(6)]*

B. Specific Conditions Related to Existing Manufacturing, Commercial, Mining, and Silviculture Wastewater Facilities or Activities

1. Existing manufacturing, commercial, mining, and silvicultural wastewater facilities or activities that discharge into surface waters shall notify the Department as soon as they know or have reason to believe:

   a. That any activity has occurred or will occur which would result in the discharge, on a routine or frequent basis, of any toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following levels;
      (1) One hundred micrograms per liter,
      (2) Two hundred micrograms per liter for acrolein and acrylonitrile; five hundred micrograms per liter for 2, 4-dinitrophenol and for 2-methyl-4, 6-dinitrophenol; and one milligram per liter for antimony, or
      (3) Five times the maximum concentration value reported for that pollutant in the permit application; or

   b. That any activity has occurred or will occur which would result in any discharge, on a non-routine or infrequent basis, of a toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following levels;
      (1) Five hundred micrograms per liter,
      (2) One milligram per liter for antimony, or
      (3) Ten times the maximum concentration value reported for that pollutant in the permit application.

   [62-620.625(1)]

C. Duty to Reapply

1. The permittee is not authorized to discharge to waters of the State after the expiration date of this permit, unless:

   a. the permittee has applied for renewal of this permit at least 180 days before the expiration date (**Month, Day, Year**) using the appropriate forms listed in Rule 62-620.910, F.A.C., and in the manner established in the Department of Environmental Protection Guide to Permitting Wastewater Facilities or Activities Under Chapter 62-620, F.A.C., including submittal of the appropriate processing fee set forth in Rule 62-4.050, F.A.C.; or

   b. the permittee has made complete the application for renewal of this permit before the permit expiration date.

   [62-620.335(1)-(4), F.A.C.]

D. Reopener Clauses

1. The permit shall be revised, or alternatively, revoked and reissued in accordance with the provisions contained in Rules 62-620.325 and 62-620.345 F.A.C., if applicable, or to comply with any applicable effluent standard or limitation issued or approved under Sections 301(b)(2)(C) and (D), 304(b)(2) and 307(a)(2) of the Clean Water Act (the Act), as amended, if the effluent standards, limitations, or water quality standards so issued or approved:

   a. Contains different conditions or is otherwise more stringent than any condition in the permit/or;

   b. Controls any pollutant not addressed in the permit.

   The permit as revised or reissued under this paragraph shall contain any other requirements then applicable.

2. The permit may be reopened to adjust effluent limitations or monitoring requirements should future Water Quality Based Effluent Limitation determinations, water quality studies, DEP approved changes in water quality standards, EPA established Total Maximum Daily Loads (TMDLs), or other information show a need for a different limitation, monitoring requirement, or more stringent requirements or any applicable standards pertaining to the operation and maintenance of coal combustion waste impoundments.

3. The Department or EPA may develop a TMDL during the life of the permit. Once a TMDL has been established and adopted by rule, the Department shall revise this permit to incorporate the final findings of the TMDL.

4. The permit shall be reopened for revision as appropriate to address new information that was not available at the time of this permit issuance or to comply with requirements of new regulations, standards, or judicial decisions relating to CWA 316(b).

IX. GENERAL CONDITIONS

1. The terms, conditions, requirements, limitations and restrictions set forth in this permit are binding and enforceable pursuant to Chapter 403, Florida Statutes. Any permit noncompliance constitutes a violation of Chapter 403, Florida Statutes, and is grounds for enforcement action, permit termination, permit revocation and reissuance, or permit revision. *[62-620.610(1)]*

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviations from the approved drawings, exhibits, specifications or conditions of this permit constitutes grounds for revocation and enforcement action by the Department. *[62-620.610(2)]*

3. As provided in subsection 403.087(7), F.S., the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor authorize any infringement of federal, state, or local laws or regulations. This permit is not a waiver of or approval of any other Department permit or authorization that may be required for other aspects of the total project which are not addressed in this permit. *[62-620.610(3)]*

4. This permit conveys no title to land or water, does not constitute state recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title. *[62-620.610(4)]*

5. This permit does not relieve the permittee from liability and penalties for harm or injury to human health or welfare, animal or plant life, or property caused by the construction or operation of this permitted source; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department. The permittee shall take all reasonable steps to

minimize or prevent any discharge, reuse of reclaimed water, or residuals use or disposal in violation of this permit which has a reasonable likelihood of adversely affecting human health or the environment. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. *[62-620.610(5)]*

6. If the permittee wishes to continue an activity regulated by this permit after its expiration date, the permittee shall apply for and obtain a new permit. *[62-620.610(6)]*

7. The permittee shall at all times properly operate and maintain the facility and systems of treatment and control, and related appurtenances, that are installed and used by the permittee to achieve compliance with the conditions of this permit. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to maintain or achieve compliance with the conditions of the permit. *[62-620.610(7)]*

8. This permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit revision, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance does not stay any permit condition. *[62-620.610(8)]*

9. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, including an authorized representative of the Department and authorized EPA personnel, when applicable, upon presentation of credentials or other documents as may be required by law, and at reasonable times, depending upon the nature of the concern being investigated, to:

   a. Enter upon the permittee's premises where a regulated facility, system, or activity is located or conducted, or where records shall be kept under the conditions of this permit;

   b. Have access to and copy any records that shall be kept under the conditions of this permit;

   c. Inspect the facilities, equipment, practices, or operations regulated or required under this permit; and

   d. Sample or monitor any substances or parameters at any location necessary to assure compliance with this permit or Department rules.

   [62-620.610(9)]

10. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data, and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except as such use is proscribed by Section 403.111, F.S., or Rule 62-620.302, F.A.C. Such evidence shall only be used to the extent that it is consistent with the Florida Rules of Civil Procedure and applicable evidentiary rules. *[62-620.610(10)]*

11. When requested by the Department, the permittee shall within a reasonable time provide any information required by law which is needed to determine whether there is cause for revising, revoking and reissuing, or terminating this permit, or to determine compliance with the permit. The permittee shall also provide to the Department upon request copies of records required by this permit to be kept. If the permittee becomes aware of relevant facts that were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be promptly submitted or corrections promptly reported to the Department. *[62-620.610(11)]*

12. Unless specifically stated otherwise in Department rules, the permittee, in accepting this permit, agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance; provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.. A reasonable time for compliance with a new or amended surface water quality standard, other than those standards addressed in Rule 62-302.500, F.A.C., shall include a reasonable time to obtain or be denied a mixing zone for the new or amended standard. *[62-620.610(12)]*

13. The permittee, in accepting this permit, agrees to pay the applicable regulatory program and surveillance fee in accordance with Rule 62-4.052, F.A.C. *[62-620.610(13)]*

14. This permit is transferable only upon Department approval in accordance with Rule 62-620.340, F.A.C. The permittee shall be liable for any noncompliance of the permitted activity until the transfer is approved by the Department. *[62-620.610(14)]*

15. The permittee shall give the Department written notice at least 60 days before inactivation or abandonment of a wastewater facility or activity and shall specify what steps will be taken to safeguard public health and safety during and following inactivation or abandonment. *[62-620.610(15)]*

16. The permittee shall apply for a revision to the Department permit in accordance with Rules 62-620.300, F.A.C., and the Department of Environmental Protection Guide to Permitting Wastewater Facilities or Activities Under Chapter 62-620, F.A.C., at least 90 days before construction of any planned substantial modifications to the permitted facility is to commence or with Rule 62-620.325(2), F.A.C., for minor modifications to the permitted facility. A revised permit shall be obtained before construction begins except as provided in Rule 62-620.300, F.A.C. *[62-620.610(16)]*

17. The permittee shall give advance notice to the Department of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements. The permittee shall be responsible for any and all damages which may result from the changes and may be subject to enforcement action by the Department for penalties or revocation of this permit. The notice shall include the following information:

    a. A description of the anticipated noncompliance;

    b. The period of the anticipated noncompliance, including dates and times; and

    c. Steps being taken to prevent future occurrence of the noncompliance.

    [62-620.610(17)]

18. Sampling and monitoring data shall be collected and analyzed in accordance with Rule 62-4.246 and Chapters 62-160, 62-601, and 62-610, F.A.C., and 40 CFR 136, as appropriate.

    a. Monitoring results shall be reported at the intervals specified elsewhere in this permit and shall be reported on a Discharge Monitoring Report (DMR), DEP Form 62-620.910(10), or as specified elsewhere in the permit.

    b. If the permittee monitors any contaminant more frequently than required by the permit, using Department approved test procedures, the results of this monitoring shall be included in the calculation and reporting of the data submitted in the DMR.

    c. Calculations for all limitations which require averaging of measurements shall use an arithmetic mean unless otherwise specified in this permit.

    d. Except as specifically provided in Rule 62-160.300, F.A.C., any laboratory test required by this permit shall be performed by a laboratory that has been certified by the Department of Health Environmental Laboratory Certification Program (DOH ELCP). Such certification shall be for the matrix, test method and analyte(s) being measured to comply with this permit. For domestic wastewater facilities, testing for parameters listed in Rule 62-160.300(4), F.A.C., shall be conducted under the direction of a certified operator.

    e. Field activities including on-site tests and sample collection shall follow the applicable standard operating procedures described in DEP-SOP-001/01 adopted by reference in Chapter 62-160, F.A.C.

    f. Alternate field procedures and laboratory methods may be used where they have been approved in accordance with Rules 62-160.220, and 62-160.330, F.A.C.

    [62-620.610(18)]

19. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule detailed elsewhere in this permit shall be submitted no later than 14 days following each schedule date. *[62-620.610(19)]*

20. The permittee shall report to the Department's Tallahassee any noncompliance which may endanger health or the environment. Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided within five days of the time the permittee becomes aware of the circumstances. The written submission shall contain: a description of the noncompliance and its cause; the period of noncompliance including exact dates and time, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

    a. The following shall be included as information which must be reported within 24 hours under this condition:
        (1) Any unanticipated bypass which causes any reclaimed water or effluent to exceed any permit limitation or results in an unpermitted discharge,
        (2) Any upset which causes any reclaimed water or the effluent to exceed any limitation in the permit,
        (3) Violation of a maximum daily discharge limitation for any of the pollutants specifically listed in the permit for such notice, and
        (4) Any unauthorized discharge to surface or ground waters.

    b. Oral reports as required by this subsection shall be provided as follows:
        (1) For unauthorized releases or spills of treated or untreated wastewater reported pursuant to subparagraph (a)4. that are in excess of 1,000 gallons per incident, or where information indicates that public health or the environment will be endangered, oral reports shall be provided to the STATE WARNING POINT TOLL FREE NUMBER (800) 320-0519, as soon as practical, but no later than 24 hours from the time the permittee becomes aware of the discharge. The permittee, to the extent known, shall provide the following information to the State Warning Point:
            (a) Name, address, and telephone number of person reporting;
            (b) Name, address, and telephone number of permittee or responsible person for the discharge;
            (c) Date and time of the discharge and status of discharge (ongoing or ceased);
            (d) Characteristics of the wastewater spilled or released (untreated or treated, industrial or domestic wastewater);
            (e) Estimated amount of the discharge;
            (f) Location or address of the discharge;
            (g) Source and cause of the discharge;
            (h) Whether the discharge was contained on-site, and cleanup actions taken to date;
            (i) Description of area affected by the discharge, including name of water body affected, if any; and
            (j) Other persons or agencies contacted.
        (2) Oral reports, not otherwise required to be provided pursuant to subparagraph b.1 above, shall be provided to the Department's Tallahassee within 24 hours from the time the permittee becomes aware of the circumstances.

    c. If the oral report has been received within 24 hours, the noncompliance has been corrected, and the noncompliance did not endanger health or the environment, the Department's Tallahassee shall waive the written report.

    [62-620.610(20)]

21. The permittee shall report all instances of noncompliance not reported under Permit Conditions IX. 17, 18 or 19 of this permit at the time monitoring reports are submitted. This report shall contain the same information required by Permit Condition IX.20 of this permit. *[62-620.610(21)]*

22. Bypass Provisions.

    a. "Bypass" means the intentional diversion of waste streams from any portion of a treatment works.

b. Bypass is prohibited, and the Department may take enforcement action against a permittee for bypass, unless the permittee affirmatively demonstrates that:
   (1) Bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and
   (2) There were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if adequate back-up equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass which occurred during normal periods of equipment downtime or preventive maintenance; and
   (3) The permittee submitted notices as required under Permit Condition IX. 22. b. of this permit.

c. If the permittee knows in advance of the need for a bypass, it shall submit prior notice to the Department, if possible at least 10 days before the date of the bypass. The permittee shall submit notice of an unanticipated bypass within 24 hours of learning about the bypass as required in Permit Condition IX. 20. of this permit. A notice shall include a description of the bypass and its cause; the period of the bypass, including exact dates and times; if the bypass has not been corrected, the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence of the bypass.

d. The Department shall approve an anticipated bypass, after considering its adverse effect, if the permittee demonstrates that it will meet the three conditions listed in Permit Condition IX. 22. a. 1 through 3 of this permit.

e. A permittee may allow any bypass to occur which does not cause reclaimed water or effluent limitations to be exceeded if it is for essential maintenance to assure efficient operation. These bypasses are not subject to the provisions of Permit Condition IX. 22. a. through c. of this permit.

[62-620.610(22)]

23. Upset Provisions.

a. "Upset" means an exceptional incident in which there is unintentional and temporary noncompliance with technology-based effluent limitations because of factors beyond the reasonable control of the permittee.
   (1) An upset does not include noncompliance caused by operational error, improperly designed treatment facilities, inadequate treatment facilities, lack of preventive maintenance, careless or improper operation.
   (2) An upset constitutes an affirmative defense to an action brought for noncompliance with technology based permit effluent limitations if the requirements of upset provisions of Rule 62-620.610, F.A.C., are met.

b. A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed contemporaneous operating logs, or other relevant evidence that:
   (1) An upset occurred and that the permittee can identify the cause(s) of the upset;
   (2) The permitted facility was at the time being properly operated;
   (3) The permittee submitted notice of the upset as required in Permit Condition IX.5. of this permit; and
   (4) The permittee complied with any remedial measures required under Permit Condition IX. 5. of this permit.

c. In any enforcement proceeding, the burden of proof for establishing the occurrence of an upset rests with the permittee.

d. Before an enforcement proceeding is instituted, no representation made during the Department review of a claim that noncompliance was caused by an upset is final agency action subject to judicial review.

[62-620.610(23)]

)   )

PERMITTEE: Progress Energy Florida, Inc
FACILITY: Anclote Power Plant

PERMIT NUMBER: FL0002992 (Major)
ISSUANCE DATE: January 14, 2011
EXPIRATION DATE: January 13, 2016

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENTOF
ENVIRONMENTAL PROTECTION

Janet G. Llewellyn

Janet G. Llewellyn
Director
Division of Water Resource Management
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
(850) 245-8336

Attachment(s):
Discharge Monitoring Report

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME:	Progress Energy	PERMIT NUMBER:	FL0002992-010-IW1S		
MAILING ADDRESS:	1729 Baillies Bluff Road Holiday, Florida 34691-	LIMIT:	Final	REPORT FREQUENCY:	Monthly
		CLASS SIZE:	MA	PROGRAM:	Industrial
FACILITY:	Anclote Power Plant	MONITORING GROUP NUMBER:	D-004		
LOCATION:	1729 Baillies Bluff Rd Holiday, FL 34691-9753	MONITORING GROUP DESCRIPTION:	combined plant discharge		
		RE-SUBMITTED DMR:	☐		
		NO DISCHARGE FROM SITE:	☐		
COUNTY:	Pasco	MONITORING PERIOD	From: ____________ To: ____________		
OFFICE:	Southwest District				

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Temperature (F), Intake (Mode I* and Mode II*)	Sample Measurement										
PARM Code 00011 1 Mon. Site No. [illegible]	Permit Requirement				Report Max 24-hr Avg	Report Max [illegible] Avg	Report [illegible]	DEG F		Continuous	Recorder
Temperature (F), Discharge (Mode I*, primary**)	Sample Measurement										
PARM Code 00011 1 Mon. Site No. EFF-1	Permit Requirement				Report Max 24-hr Avg	90.0 Max 1-hr Avg	92.0 Inst. Maximum	DEG F		Continuous	Recorder
Temperature Rise (Mode I*, primary**)	Sample Measurement										
PARM Code 61576 1 Mon. Site No. EFF-1	Permit Requirement				Report Max 24-hr Avg	Report Max 1-hr Avg		DEG F		Continuous	Recorder
Temperature (F), Discharge (Mode I*, alternate**)	Sample Measurement										
PARM Code 00011 P Mon. Site No. EFF-1	Permit Requirement				92.0 Max 24-hr Avg	Report Max 3-hr Avg	95.0 Max 1-hr Avg	DEG F		Continuous	Recorder
Temperature (F), Discharge (Mode I*, alternate**)	Sample Measurement										
PARM Code 00011 Q Mon. Site No. EFF-1	Permit Requirement				95.5 Inst. Maximum			DEG F		Continuous	Recorder
Temperature Rise (Mode I*, alternate**)	Sample Measurement										
PARM Code 61576 P Mon. Site No. EFF-1	Permit Requirement				Report Max 24-hr Avg	5.0 Max 3-hr Avg	Report Max 1-hr Avg	DEG F		Continuous	Recorder

*Mode I: January 1 until first instance of Temperature >= 82.0 deg F and first instance of Temperature < 82.0 deg F until December 31. Otherwise Mode II applies.

** Alternate monitoring and limitations are applicable only when the facility is unable to meet primary limitations with three cooling tower pumps and 22 cooling tower fans in operation.

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

ISSUANCE/REISSUANCE DATE

DEP Form 62-620.910(10), Effective Nov. 29, 1994

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: Anclote Power Plant

MONITORING GROUP NUMBER: D-004

PERMIT NUMBER: FL0002992-010-IW1S

MONITORING PERIOD From: ____________ To: ____________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex	Frequency of Analysis	Sample Type
Temperature (F), Discharge (Mode II*, primary**)	Sample Measurement										
PARM Code 00011 R Mon. Site No. EFF-1	Permit Requirement				Report Max 24-hr Avg	92.0 Max 3-hr Avg	95.0 Inst. Maximum	DEG.F		Continuous	Recorder
Temperature Rise (Mode II*, primary**)	Sample Measurement										
PARM Code 61576 Q Mon. Site No. EFF-1	Permit Requirement				Report Max 24-hr Avg	Report Max 1-hr Avg		DEG.F		Continuous	Recorder
Temperature (F), Discharge (Mode II*, alternate**)	Sample Measurement										
PARM Code 00011 S Mon. Site No. EFF-1	Permit Requirement				92.5 Max 24-hr Avg	Report Max 3-hr Avg	95.0 Max 1-hr Avg	DEG.F		Continuous	Recorder
Temperature (F), Discharge (Mode II*, alternate**)	Sample Measurement										
PARM Code 00011 T Mon. Site No. EFF-1	Permit Requirement				95.5 Inst. Maximum			DEG.F		Continuous	Recorder
Temperature Rise (Mode II*, alternate**)	Sample Measurement										
PARM Code 61576 R Mon. Site No. EFF-1	Permit Requirement				Report Max 24-hr Avg	5.0 Max 3-hr Avg	Report Max 1-hr Avg	DEG.F		Continuous	Recorder
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										

*Mode I: January 1 until first instance of Temperature >= 82.0 deg F and first instance of Temperature < 82.0 deg F until December 31; Otherwise Mode II applies.

** Alternate monitoring and limitations are applicable only when the facility is unable to meet primary limitations with three cooling tower pumps and 22 cooling tower fans in operation.

Docket No. 110007-EI
Progress Energy Florida
Witness: Patricia Q. West
Exhibit No. __ (PQW-1)
Page 75 of 85

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME: Progress Energy
MAILING ADDRESS: 1729 Baillies Bluff Road
Holiday, Florida 34691-

FACILITY: Anclote Power Plant
LOCATION: 1729 Baillies Bluff Rd
Holiday, FL 34691-9753

COUNTY: Pasco
OFFICE: Southwest District

PERMIT NUMBER: FL0002992-010-IW1S

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: D-004
MONITORING GROUP DESCRIPTION: combined plant discharge
RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: ______ To: ______

REPORT FREQUENCY: Quarterly
PROGRAM: Industrial

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Temperature (C), Water	Sample Measurement										
PARM Code 00010 7 Mon. Site No. INT-1	Permit Requirement						Report (Max)	Deg C		Quarterly	Grab
Temperature (C), Water	Sample Measurement										
PARM Code 00010 Q Mon. Site No. EFF-1	Permit Requirement						Report (Max)	Deg C		Quarterly	Grab
pH	Sample Measurement										
PARM Code 00400 7 Mon. Site No. INT-1	Permit Requirement						Report (Max)	mg/L		Quarterly	Grab
pH	Sample Measurement										
PARM Code 00400 Q Mon. Site No. EFF-1	Permit Requirement						Report (Max)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N)	Sample Measurement										
PARM Code 00610 7 Mon. Site No. INT-1	Permit Requirement						Report (Max)	mg/L		Quarterly	Grab
Nitrogen, Ammonia, Total (as N)	Sample Measurement										
PARM Code 00610 Q Mon. Site No. EFF-1	Permit Requirement						Report (Max)	mg/L		Quarterly	Grab
Ammonia, Unionized (as NH3)	Sample Measurement										
PARM Code 00619 7 Mon. Site No. INT-1	Permit Requirement						Report (Max)	mg/L		Quarterly	Calculated

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

ISSUANCE/REISSUANCE DATE:

DEP Form 62-620.910(10), Effective Nov. 29, 1994

Docket No. 110007-EI
Progress Energy Florida
Witness: Patricia Q. West
Exhibit No. __ (PQW-1)
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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: Anclote Power Plant

MONITORING GROUP NUMBER: D-004

PERMIT NUMBER: FL0002992-010-IW1S

MONITORING PERIOD From: ____________ To: ____________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Ammonia, Unionized (as NH3)	Sample Measurement										
PARM Code 00619 Q Mon. Site No. EFF-1	Permit Requirement						Report (Max.)	mg/L		Quarterly	Calculated
Nitrogen, Kjeldahl, Total (as N)	Sample Measurement										
PARM Code 00625 7 Mon. Site No. INT-1	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Nitrogen, Kjeldahl, Total (as N)	Sample Measurement										
PARM Code 00625 Q Mon. Site No. EFF-1	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N)	Sample Measurement										
PARM Code 00630 7 Mon. Site No. INT-1	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Nitrite plus Nitrate, Total 1 det. (as N)	Sample Measurement										
PARM Code 00630 Q Mon. Site No. EFF-1	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Nitrogen, Total	Sample Measurement										
PARM Code 00600 7 Mon. Site No. INT-1	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Nitrogen, Total	Sample Measurement										
PARM Code 00600 Q Mon. Site No. EFF-1	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P)	Sample Measurement										
PARM Code 00665 7 Mon. Site No. INT-1	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphorus, Total (as P)	Sample Measurement										
PARM Code 00665 Q Mon. Site No. EFF-1	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4)	Sample Measurement										
PARM Code 00660 7 Mon. Site No. INT-1	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab
Phosphate, Ortho (as PO4)	Sample Measurement										
PARM Code 00660 Q Mon. Site No. EFF-1	Permit Requirement						Report (Max.)	mg/L		Quarterly	Grab

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Witness: Patricia Q. West
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ISSUANCE/REISSUANCE DATE:

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME: Progress Energy
MAILING ADDRESS: 1729 Baillies Bluff Road
Holiday, Florida 34691-

FACILITY: Anclote Power Plant
LOCATION: 1729 Baillies Bluff Rd
Holiday, FL 34691-9753

COUNTY: Pasco

OFFICE: Southwest District

PERMIT NUMBER: FL0002992-010-IW1S

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: D-004
MONITORING GROUP DESCRIPTION: combined plant discharge
RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING NOT REQUIRED: ☐
MONITORING PERIOD From: ________ To: ________

REPORT FREQUENCY: Toxicity
PROGRAM: Industrial

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
7-DAY CHRONIC STATRE Mysidopsis bahia(Routine)	Sample Measurement										
PARM Code TRP3B P Mon. Site No. EFF-1	Permit Requirement				100 (Min.)			percent		Quarterly	24-hr TPC
7-DAY CHRONIC STATRE Mysidopsis bahia(Additional)	Sample Measurement										
PARM Code TRP3B Q Mon. Site No. EFF-1	Permit Requirement				100 (Min.)			percent		As needed	As required by the permit
7-DAY CHRONIC STATRE Mysidopsis bahia(Additional)	Sample Measurement										
PARM Code TRP3B R Mon. Site No. EFF-1	Permit Requirement				100 (Min.)			percent		As needed	As required by the permit
7-DAY CHRONIC STATRE Menidia beryllina(Routine)	Sample Measurement										
PARM Code TRP6B P Mon. Site No. EFF-1	Permit Requirement				100 (Min.)			percent		Quarterly	24-hr TPC
7-DAY CHRONIC STATRE Menidia beryllina(Additional)	Sample Measurement										
PARM Code TRP6B Q Mon. Site No. EFF-1	Permit Requirement				100 (Min.)			percent		As needed	As required by the permit
7-DAY CHRONIC STATRE Menidia beryllina(Additional)	Sample Measurement										
PARM Code TRP6B R Mon. Site No. EFF-1	Permit Requirement				100 (Min.)			percent		As needed	As required by the permit

*ENTER "MNR" IN THE RESULTS COLUMN FOR EACH TEST THAT IS NOT REQUIRED.

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here)

ISSUANCE/REISSUANCE DATE:

DEP Form 62-620.910(10), Effective Nov. 29, 1994

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME: Progress Energy
MAILING ADDRESS: 1729 Baillies Bluff Road
Holiday, Florida 34691-

FACILITY: Anclote Power Plant
LOCATION: 1729 Baillies Bluff Rd
Holiday, FL 34691-9753

COUNTY: Pasco
OFFICE: Southwest District

PERMIT NUMBER: FL0002992-010-IW1S

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: 1-001
MONITORING GROUP DESCRIPTION: Once-through condenser cooling water from Unit 1
RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: ________ To: ________

REPORT FREQUENCY: Monthly
PROGRAM: Industrial

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Flow(Total Units 1 and 2 OTCW)	Sample Measurement										
PARM Code 50050 1 Mon. Site No. EFW-1	Permit Requirement		Report (Day Avg.)	MGD						Daily; 24 hours	Pump Logs
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										
	Sample Measurement										
	Permit Requirement										

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NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO.	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

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ISSUANCE/REISSUANCE DATE

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME: Progress Energy
MAILING ADDRESS: 1729 Baillies Bluff Road, Holiday, Florida 34691-

FACILITY: Anclote Power Plant
LOCATION: 1729 Baillies Bluff Rd, Holiday, FL 34691-9753

COUNTY: Pasco
OFFICE: Southwest District

PERMIT NUMBER: FL0002992-010-IW1S
LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: I-003
MONITORING GROUP DESCRIPTION: Dilution pump flow to the discharge canal.
RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: ____ To: ____

REPORT FREQUENCY: Monthly
PROGRAM: Industrial

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Flow	Sample Measurement										
PARM Code 50050 1 Mon. Site No. FLW-2	Permit Requirement		Report (Day Avg.)	MGD						Daily; 24 hours	Pump Logs
Duration of Discharge	Sample Measurement										
PARM Code 81381 1 Mon. Site No. FLW-2	Permit Requirement		Report (Day Avg.)	hr/mth						Daily; 24 hours	Pump Logs

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. *I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.*

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here).

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DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME: Progress Energy
MAILING ADDRESS: 1729 Baillies Bluff Road
Holiday, Florida 34691-

FACILITY: Anclote Power Plant
LOCATION: 1729 Baillies Bluff Rd
Holiday, FL 34691-9733

COUNTY: Pasco
OFFICE: Southwest District

PERMIT NUMBER: FL0002992-010-IW1S

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: I-005
MONITORING GROUP DESCRIPTION: Cooling tower discharge to the discharge canal.
RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: ____________ To: ____________

REPORT FREQUENCY: Monthly
PROGRAM: Industrial

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex	Frequency of Analysis	Sample Type
TRO-Discharge Time	Sample Measurement										
PARM Code 04223 1 Mon. Site No. EFF-2	Permit Requirement						120 (Inst.Max.)	min/day		Daily; 24 hours	Calculated
Oxidants, Total Residual	Sample Measurement										
PARM Code 34044 1 Mon. Site No. EFF-1	Permit Requirement						0.01 (Inst.Max.)	mg/L		Weekly	Grab
Oxidants, Total Residual	Sample Measurement										
PARM Code 34044 Q Mon. Site No. EFF-2	Permit Requirement						0.05 (Inst.Max.)	mg/L		Weekly	Meter
Dosage Rate*	Sample Measurement										
PARM Code 82391 1 Mon. Site No. INT-2	Permit Requirement	500 Inst. Maximum		lbs/day						Daily	Calculated

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

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COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here).

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ISSUANCE/REISSUANCE DATE.

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME: Progress Energy
MAILING ADDRESS: 1729 Baillies Bluff Road
Holiday, Florida 34691-

FACILITY: Anclote Power Plant
LOCATION: 1729 Baillies Bluff Rd
Holiday, FL 34691-9753

COUNTY: Pasco
OFFICE: Southwest District

PERMIT NUMBER: FL0002992-010-IW1S

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: I-006
MONITORING GROUP DESCRIPTION: storm water discharge
RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: ________ To: ________

REPORT FREQUENCY: Monthly
PROGRAM: Industrial

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Flow	Sample Measurement										
PARM Code 50050 1 Mon. Site No. EFF-3	Permit Requirement		Report (Day Max.)	MGD						Monthly, when discharging	Calculated
Copper, Total Recoverable	Sample Measurement										
PARM Code 01119 1 Mon. Site No. EFF-3	Permit Requirement						Report (Day Max)	ug/L		Monthly, when discharging	Grab
Iron, Total Recoverable	Sample Measurement										
PARM Code 00980 1 Mon. Site No. EFF-3	Permit Requirement						Report (Day Max.)	mg/L		Monthly, when discharging	Grab

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO.	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

Docket No. 110007-EI
Progress Energy Florida
Witness: Patricia Q. West
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INSTRUCTIONS FOR COMPLETING THE WASTEWATER DISCHARGE MONITORING REPORT

Read these instructions before completing the DMR. Hard copies and/or electronic copies of the required parts of the DMR were provided with the permit. All required information shall be completed in full and typed or printed in ink. A signed, original DMR shall be mailed to the address printed on the DMR by the 28th of the month following the monitoring period. The DMR shall not be submitted before the end of the monitoring period.

The DMR consists of three parts--A, B, and D--all of which may or may not be applicable to every facility. Facilities may have one or more Part A's for reporting effluent or reclaimed water data. All domestic wastewater facilities will have a Part B for reporting daily sample results. Part D is used for reporting ground water monitoring well data.

When results are not available, the following codes should be used on parts A and D of the DMR and an explanation provided where appropriate. Note: Codes used on Part B for raw data are different.

CODE	DESCRIPTION/INSTRUCTIONS
ANC	Analysis not conducted.
DRY	Dry Well
FLD	Flood disaster.
IFS	Insufficient flow for sampling.
LS	Lost sample.
MNR	Monitoring not required this period

CODE	DESCRIPTION/INSTRUCTIONS
NOD	No discharge from/to site.
OPS	Operations were shutdown so no sample could be taken.
OTH	Other. Please enter an explanation of why monitoring data were not available
SEF	Sampling equipment failure.

When reporting analytical results that fall below a laboratory's reported method detection limits or practical quantification limits, the following instructions should be used:

1. Results greater than or equal to the PQL shall be reported as the measured quantity.
2. Results less than the PQL and greater than or equal to the MDL shall be reported as the laboratory's MDL value. These values shall be deemed equal to the MDL when necessary to calculate an average for that parameter and when determining compliance with permit limits.
3. Results less than the MDL shall be reported by entering a less than sign ("<") followed by the laboratory's MDL value, e.g. < 0.001. A value of one-half the MDL or one-half the effluent limit, whichever is lower, shall be used for that sample when necessary to calculate an average for that parameter. Values less than the MDL are considered to demonstrate compliance with an effluent limitation.

PART A - DISCHARGE MONITORING REPORT (DMR)

Part A of the DMR is comprised of one or more sections, each having its own header information. Facility information is preprinted in the header as well as the monitoring group number, whether the limits and monitoring requirements are interim or final, and the required submittal frequency (e.g. monthly, annually, quarterly, etc.). Submit Part A based on the required reporting frequency in the header and the instructions shown in the permit. The following should be completed by the permittee or authorized representative:

Resubmitted DMR: Check this box if this DMR is being re-submitted because there was information missing from or information that needed correction on a previously submitted DMR. The information that is being revised should be clearly noted on the re-submitted DMR (e.g. highlight, circle, etc.)
No Discharge From Site: Check this box if no discharge occurs and, as a result, there are no data or codes to be entered for all of the parameters on the DMR for the entire monitoring group number; however, if the monitoring group includes other monitoring locations (e.g., influent sampling), the "NOD" code should be used to individually denote those parameters for which there was no discharge.
Monitoring Period: Enter the month, day, and year for the first and last day of the monitoring period (i.e. the month, the quarter, the year, etc.) during which the data on this report were collected and analyzed.
Sample Measurement: Before filling in sample measurements in the table, check to see that the data collected correspond to the limit indicated on the DMR (i.e. interim or final) and that the data correspond to the monitoring group number in the header. Enter the data or calculated results for each parameter on this row in the non-shaded area above the limit. Be sure the result being entered corresponds to the appropriate statistical base code (e.g. annual average, monthly average, single sample maximum, etc.) and units.
No. Ex.: Enter the number of sample measurements during the monitoring period that exceeded the permit limit for each parameter in the non-shaded area. If none, enter zero.
Frequency of Analysis: The shaded areas in this column contain the minimum number of times the measurement is required to be made according to the permit. Enter the actual number of times the measurement was made in the space above the shaded area.
Sample Type: The shaded areas in this column contain the type of sample (e.g. grab, composite, continuous) required by the permit. Enter the actual sample type that was taken in the space above the shaded area.
Signature: This report must be signed in accordance with Rule 62-620.305, F.A.C. Type or print the name and title of the signing official. Include the telephone number where the official may be reached in the event there are questions concerning this report. Enter the date when the report is signed.
Comment and Explanation of Any Violations: Use this area to explain any exceedances, any upset or by-pass events, or other items which require explanation. If more space is needed, reference all attachments in this area.

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PART B - DAILY SAMPLE RESULTS

Monitoring Period: Enter the month, day, and year for the first and last day of the monitoring period (i.e. the month, the quarter, the year, etc.) during which the data on this report were collected and analyzed.

Daily Monitoring Results: Transfer all analytical data from your facility's laboratory or a contract laboratory's data sheets for all day(s) that samples were collected. Record the data in the units indicated. Table 1 in Chapter 62-160, F.A.C., contains a complete list of all the data qualifier codes that your laboratory may use when reporting analytical results. However, when transferring numerical results onto Part B of the DMR, only the following data qualifier codes should be used and an explanation provided where appropriate.

CODE	DESCRIPTION/INSTRUCTIONS
<	The compound was analyzed for but not detected.
A	Value reported is the mean (average) of two or more determinations.
J	Estimated value, value not accurate.
Q	Sample held beyond the actual holding time.
Y	Laboratory analysis was from an unpreserved or improperly preserved sample.

To calculate the monthly average, add each reported value to get a total. For flow, divide this total by the number of days in the month. For all other parameters, divide the total by the number of observations.

Plant Staffing: List the name, certificate number, and class of all state certified operators operating the facility during the monitoring period. Use additional sheets as necessary.

PART D - GROUND WATER MONITORING REPORT

Monitoring Period: Enter the month, day, and year for the first and last day of the monitoring period (i.e. the month, the quarter, the year, etc.) during which the data on this report were collected and analyzed

Date Sample Obtained: Enter the date the sample was taken. Also, check whether or not the well was purged before sampling.

Time Sample Obtained: Enter the time the sample was taken.

Sample Measurement: Record the results of the analysis. If the result was below the minimum detection limit, indicate that.

Detection Limits: Record the detection limits of the analytical methods used.

Analysis Method: Indicate the analytical method used. Record the method number from Chapter 62-160 or Chapter 62-601, F.A.C., or from other sources

Sampling Equipment Used: Indicate the procedure used to collect the sample (e.g. airlift, bucket/bailer, centrifugal pump, etc.)

Samples Filtered: Indicate whether the sample obtained was filtered by laboratory (L), filtered in field (F), or unfiltered (N).

Signature: This report must be signed in accordance with Rule 62-620.305, F.A.C. Type or print the name and title of the signing official. Include the telephone number where the official may be reached in the event there are questions concerning this report. Enter the date when the report is signed.

Comments and Explanation: Use this space to make any comments on or explanations of results that are unexpected. If more space is needed, reference all attachments in this area.

SPECIAL INSTRUCTIONS FOR LIMITED WET WEATHER DISCHARGES

Flow (Limited Wet Weather Discharge): Enter the measured average flow rate during the period of discharge or divide gallons discharged by duration of discharge (converted into days). Record in million gallons per day (MGD)

Flow (Upstream): Enter the average flow rate in the receiving stream upstream from the point of discharge for the period of discharge. The average flow rate can be calculated based on two measurements; one made at the start and one made at the end of the discharge period. Measurements are to be made at the upstream gauging station described in the permit.

Actual Stream Dilution Ratio: To calculate the *Actual Stream Dilution Ratio*, divide the average upstream flow rate by the average discharge flow rate. Enter the Actual Stream Dilution Ratio accurate to the nearest 0.1.

No. of Days the SDF > Stream Dilution Ratio: For each day of discharge, compare the minimum Stream Dilution Factor (SDF) from the permit to the calculated Stream Dilution Ratio. On Part B of the DMR, enter an asterisk (*) if the SDF is greater than the Stream Dilution Ratio on any day of discharge. On Part A of the DMR, add up the days with an "*" and record the total number of days the Stream Dilution Factor was greater than the Stream Dilution Ratio

$CBOD_5$: Enter the average $CBOD_5$ of the reclaimed water discharged during the period shown in duration of discharge.

TKN: Enter the average TKN of the reclaimed water discharged during the period shown in duration of discharge.

Actual Rainfall: Enter the actual rainfall for each day on Part B. Enter the actual cumulative rainfall to date for this calendar year and the actual total monthly rainfall on Part A. The cumulative rainfall to date for this calendar year is the total amount of rain, in inches, that has been recorded since January 1 of the current year through the month for which this DMR contains data.

Rainfall During Average Rainfall Year: On Part A, enter the total monthly rainfall during the average rainfall year and the cumulative rainfall for the average rainfall year. The cumulative rainfall for the average rainfall year is the amount of rain, in inches, which fell during the average rainfall year from January through the month for which this DMR contains data.

No. of Days LWWD Activated During Calendar Year: Enter the cumulative number of days that the limited wet weather discharge was activated since January 1 of the current year.

Reason for Discharge: Attach to the DMR a brief explanation of the factors contributing to the need to activate the limited wet weather discharge.

EXHIBIT "C"

REDACTED

Projected Compliance Costs for NPDES Renewal Permits

Project	Plant/Year							
	Bartow		Anclote		Crystal River		Suwannee	
	2011	2012	2011	2012	2011	2012	2011	2012
Thermal Studies	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Aquatic Org. Ret. Studies & Implementation	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Whole Effluent Toxicity Testing	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Dissolved Oxygen Study	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Freeboard Limitation & Related Studies	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
TOTAL COSTS	$635,000	$240,000	$145,000	$55,000	$210,000	$85,000	$120,000	$50,000

BEFORE THE PUBLIC SERVICE COMMISSION

In re: Environmental Cost Recovery Clause	DOCKET NO. 110007-EI
	FILED: May 24, 2011

PROGRESS ENERGY FLORIDA, INC.'S PETITION TO MODIFY SCOPE OF EXISTING ENVIRONMENTAL PROGRAM

Progress Energy Florida, Inc. ("PEF" or "Company"), pursuant to Section 366.8255, Florida Statutes, and Florida Public Service Commission Order Nos. PSC-94-0044-FOF-EI and PSC-99-2513-FOF-EI, hereby petitions the Commission to modify the scope of its previously approved Integrated Clean Air Compliance Program to encompass additional activities such that the costs associated with such activities prudently incurred after the filing of this Petition may be recovered through the Environmental Cost Recovery Clause ("ECRC"). In support, PEF states:

1. Petitioner. PEF is a public utility subject to the regulatory jurisdiction of the Commission under Chapter 366, Florida Statutes. The Company's principal offices are located at 299 First Avenue North, St. Petersburg, Florida.

2. Service. All notices, pleadings and other communications required to be served on the petitioner should be directed to:

Gary V. Perko	John T. Burnett
Hopping Green & Sams, P.A.	Dianne M. Triplett
119 S. Monroe St., Suite 300	Progress Energy Services Co., LLC
P.O. Box 6526 (32314)	299 First Avenue North, PEF-151
Tallahassee, FL 32301	St. Petersburg, FL 33701

3. Cost Recovery Eligibility. As further discussed below, the U.S. Environmental Protection Agency ("EPA") recently issued proposed rules that would establish new standards for air emissions from coal- and oil-fired electric generating units. As a result of the new regulations, PEF will incur costs for new environmental compliance activities related to its

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI EXHIBIT 20
PARTY PROGRESS ENERGY FLORIDA
DESCRIPTION PATRICIA Q. WEST (PQW-3)
DATE 11/01/11

DOCUMENT NUMBER-DATE
03631 MAY 24 =
FPSC-COMMISSION CLERK

previously approved Integrated Clean Air Compliance Program. As detailed below, the new compliance activities meet the criteria for cost recovery established by the Commission in Order No. PSC-94-0044-FOF-EI in that:

(a) all expenditures will be prudently incurred after April 13, 1993;

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

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

The information provided below for each program satisfies the minimum filing requirements established in Part VI of Order No. PSC-99-2513-FOF-EI.

4. New Rules Affecting PEF's Approved Integrated Clean Air Compliance Plan. In the 2007 ECRC Docket, the Commission approved PEF's Integrated Clean Air Compliance Plan (Plan D) as a reasonable and prudent means to comply with the requirements of the Clean Air Interstate Rule (CAIR), the Clean Air Mercury Rule (CAMR), the Clean Air Visibility Rule (CAVR), and related regulatory requirements. Order No. PSC-07-0922-FOF-EI, at 8 (Nov. 16, 2007). In each subsequent ECRC docket, the Commission approved PEF's annual review of the Integrated Clean Air Compliance Plan, concluding that the Plan remains the most cost-effective alternative for achieving and maintaining compliance with the applicable air quality control and monitoring regulatory requirements. See Order No. PSC-10-0683-FOF-EI, at 6-7 (Nov. 15, 2010); Order No. PSC-09-0759-FOF-EI, at 18 (Nov. 18, 2009); Order No. 08-0775-FOF-EI, at 11 (Nov. 24, 2008).

As the Commission is aware, in February 2008, the U.S Circuit Court of Appeals for the District of Columbia vacated the CAMR regulation and rejected EPA's delisting of coal-fired electric generating units from the list of emission sources that are subject to Section 112 of the Clean Air Act. See Order No. PSC-09-0759-FOF-EI, at pp. 15, 18 (Nov. 18, 2009). As a result, in lieu of CAMR, EPA must adopt National Emission Standards for Hazardous Air Pollutants (NESHAPs) that define Maximum Available Control Technology (MACT) for control of hazardous air pollutant emissions from coal-fired electric generators. Id.

EPA issued its proposed rule to replace CAMR on March 16, 2011, with publication following in the *Federal Register* on May 3, 2011. 76 Fed. Reg. 24976 (May 3, 2011) PEF and other interested persons have 60 days following publication (i.e., July 5, 2011) to submit comments on the proposed rule to EPA. In accordance with a consent decree, the EPA Administrator must sign a final rule by November 16, 2011. The Clean Air Act generally requires affected facilities to comply with the final rule within three years of adoption, although one-year compliance extensions can be granted on a case-by-case basis. See 42 U.S.C. § 7412(i)(3).

Adoption of the new NESHAP rule will require PEF to modify its Integrated Clean Air Compliance Plan to ensure compliance with new emission standards. EPA's proposed standards apply to all existing coal- and oil-fired electric generators, including PEF's Crystal River Units 1, 2, 4, and 5, and Anclote Units 1 and 2, and Suwannee Units, 1, 2, and 3. The standards would place stringent limits on emissions of: (1) metals, including mercury, arsenic, chromium and nickel; (2) acid gases, including hydrogen chloride and hydrogen fluoride; and (3) particulate matter. Potential compliance options include installation of emission controls, fuel switches, efficiency improvements and unit retirements.

In addition to the proposed NESHAP rule, electric generating units are the subject of other ongoing rulemakings addressing the interstate transport of emissions contributing to ozone and particulate matter air quality issues, coal combustion wastes and cooling water control requirements. Harmonizing overlapping regulations and timelines could make a substantial difference in lowering costs to the customer. Accordingly, to the extent possible, PEF will take into account the combined effects of these upcoming rules in developing cost-effective alternatives for inclusion in a revised Integrated Clean Air Compliance Plan to be submitted for Commission review at a later date.

5. New Environmental Compliance Activities. The new requirements of the proposed NESHAP and other ongoing rulemakings present significant challenges to the utility industry, requiring substantial analysis and planning to develop and implement cost-effective compliance measures. At this time, PEF needs to contract with outside consultants to help the Company assess the proposed rule, prepare comments to EPA, and develop compliance strategies within the aggressive regulatory time-frames. In 2011, PEF will conduct diagnostic stack testing in order to help inform development of comments on the proposed rule and the development of compliance strategies. Specifically, PEF will perform emissions testing at Crystal River Units 4 and 5 in June, 2011, to assess emissions of mercury, HCl and condensable particulate matter at three load points while testing hydrated lime injection and various operating conditions. Upon issuance of the final rule, PEF expects to incur additional costs in 2012 for detailed engineering and other analyses necessary to develop compliance strategies for inclusion in an updated Integrated Clean Air Compliance Plan.

As the Commission has previously recognized, "[a]n effective way to control the costs of complying with a particular environmental law or regulation can be participation in the regulatory and legal processes involved in defining compliance." Order No. PSC-08-0775-FOF-EI, at 7-8 (Nov. 24, 2008). Based on that understanding, the Commission has repeatedly approved ECRC recovery of costs incurred by utilities for technical analyses and other activities associated with participation in development of regulatory compliance measures. See e.g., id. (costs for participating in rulemaking and legal proceedings related to EPA's Section 316(b) Phase II rules); Order No. PSC-09-0759-FOF-EI (Nov. 18, 2009) (costs for emissions monitoring and modeling associating with development of TMDLs and parallel air rulemaking); Order No. PSC-05-1251-FOF-EI (Dec. 22, 2005) (costs associated with technical analysis and legal challenges to Clean Air Interstate Rule); and Order No. PSC-00-0476-PAA-EI (Mar. 6, 2000) (costs associated with participating in ozone modeling study). Accordingly, PEF's costs associated with development of the NESHAP compliance measures described above are recoverable under the ECRC.

6. No Base Rates Recovery of Program Costs. PEF seeks approval to recover incremental costs associated with development of the NESHAP compliance measures. None of the costs for which PEF seeks recovery were included in the MFRs that PEF filed in its last ratemaking proceeding in Docket No. 090079-EI. Therefore, the costs are not recovered in PEF's base rates.

7. Cost Estimates. PEF expects to incur approximately $85,000 in costs for NESHAP-related activities for the remainder of 2011 and approximately $300,000 for calendar year 2012.

8. Prudence of Expenditures. In order to ensure that the costs incurred for these activities are prudent and reasonable, PEF will identify qualified contractors and, when appropriate, will use competitive bidding when appropriate.

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9. No Change in Current ECRC Factors. PEF does not seek to change the ECRC factors currently in effect for 2011. The Company proposes to include in its estimated true-up filing for 2011 all program costs incurred subsequent to the filing of this petition through the end of 2011. The Company will include program costs projected for 2012 and beyond in the appropriate projection filings. PEF expects that all of these costs will be subject to audit by the Commission and that the appropriate allocation of program costs to rate classes will be addressed in connection with those subsequent filings.

10. No Material Facts in Dispute. PEF is not aware of any dispute regarding any of the material facts contained in this petition. The information provided in this petition demonstrates that the programs for which approval is requested meets the requirements of Section 366.8255 and applicable Commission orders for recovery through the ECRC.

WHEREFORE, Progress Energy Florida, Inc., requests that the Commission approve for recovery through the ECRC all costs reasonably and prudently incurred after the date of this petition in connection with development of the NESHAP compliance measures described more fully above.

RESPECTFULLY SUBMITTED this 24th day of May, 2011.

John T. Burnett
Associate General Counsel
Dianne M. Triplett
Associate General Counsel
PROGRESS ENERGY SERVICE
COMPANY, LLC
Post Office Box 14042
St. Petersburg, FL 33733-4042

HOPPING GREEN & SAMS, P.A.

By: [signature]
Gary V. Perko
119 S. Monroe St., Ste. 300 (32301)
P.O. Box 6526
Tallahassee, FL 32314
gperko@hgslaw.com
Tel.: (850) 425-2359
Fax: (850) 224-8551

Attorneys for PROGRESS ENERGY FLORIDA, INC.

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF PINELLAS)

The undersigned Patricia Q. West, first being duly sworn, deposes and says:

1. I am employed as Manager of Environmental Services / Power Generation Florida for Progress Energy Florida, Inc.

2. I have reviewed the above Petition of Progress Energy Florida, Inc. to Modify the Scope of an Existing Environmental Program and the facts stated in that petition are true and correct to the best of my knowledge, information and belief.

Patricia Q. West
Patricia Q. West

Sworn to and subscribed before me by Patricia Q. West, who:

(✓) is personally known to me

( ) presented Florida Drivers License Number __________ as identification

this 19th day of May, 2011.

SUZANNE H. MILLER
MY COMMISSION # DD 842069
EXPIRES: March 27, 2013
Bonded Thru Notary Public Underwriters

Suzanne H Miller
Notary Public

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via hand-delivery (*) or regular U.S. mail this 24th day of May, 2011.

Martha Carter Brown (*)
Office of General Counsel
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850
mbrown@psc.state.fl.us

John T. Butler, Esq.
Florida Power & Light Co.
700 Universe Blvd.
Juno Beach, FL 33408-0420
john.butler@fpl.com

Mr. Wade Litchfield
Florida Power & Light Co.
215 S. Monroe Street, Suite 810
Tallahassee, FL 32301
wade.litchfield@fpl.com

James D. Beasley, Esq.
Ausley & McMullen
P.O. Box 391
Tallahassee, FL 32302
jbeasley@ausley.com

John W. McWhirter, Jr.
McWhirter Reeves & Davidson, P.A.
P.O. Box 3350
Tampa, FL 33601-3350
jmcwhirter@mac-law.com

Jeffrey A. Stone, Esq.
Russell A. Badders, Esq.
Beggs & Lane Law Firm
P.O. Box 12950
Pensacola, FL 32591-2950
jas@beggslane.com
rab@beggslane.com

Susan Ritenour
Gulf Power Company
One Energy Place
Pensacola, FL 32520-0780
sdriteno@southernco.com

Capt. Shayla McNeill, USAF
Federal Executive Agencies
c/o AFLSA / JACL-ULT
139 Barnes Drive, Suite 1
Tyndall AFB, FL 32403
Shayla.mcneill@tyndall.af.mil

J.R. Kelly
Charles J. Rehwinkel
Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street, Rm. 812
Tallahassee, FL 32399
Kelly.jr@leg.state.fl.us
rehwinkel.charles@leg.state.fl.us

Paula K. Brown
Tampa Electric Company
Administrator, Regulatory Coordination
P.O. Box 111
Tampa, FL 33601-0111
Regdept@tecoenergy.com

R. Alexander Glenn
Deputy General Counsel - Florida

John T. Burnett
Associate General Counsel - Florida
Progress Energy Service Company, LLC
P.O. Box 14042
St. Petersburg, FL 33733
alex.glenn@pgnmail.com

john.burnett@pgnmail.com

Paul Lewis, Jr.
Progress Energy Florida, Inc.
106 East College Avenue, Suite 800
Tallahassee, FL 32301-7740
paul.lewisjr@pgnmail.com

Attorney

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2012 - DECEMBER 2012
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Pipeline Integrity Management, Review/Update Plan and Risk Assessments
Project No. 3

Project Description:
The U.S. Department of Transportation ("USDOT") Regulation 49 CFR Part 195, as amended effective February 15, 2002 and the new regulation published at 67 Federal Register 2136 on January 16, 2002, requires PEF to implement a Pipeline Integrity Management Program. Prior to the February 15, 2002 amendments, the USDOT's pipeline integrity management regulations applied only to operators with 500 miles or more of hazardous liquid and carbon dioxide pipelines that could affect high consequence areas. The amendments which became effective on February 15, 2002 extended the requirements for implementing integrity management to operators who have less than 500 miles of regulated pipelines. As such, PEF must improve the integrity of pipeline systems in order to protect public safety and the environment, as well as comply with continual assessment and evaluation of pipeline systems integrity through inspection or testing, data integration and analysis, and follow up with remedial, preventative, and mitigative actions.

Effective February 2010, amendments to 49 CFR 195 were finalized to improve opportunities to reduce risk through more effective control of pipelines. Compliance with these amendments will enhance pipeline safety by coupling strengthened control room management with improved controller training and fatigue management. On June 16, 2011, USDOT published in the Federal Register (VOl. 76, 35130-35136), a final rule effective August 15, 2011 that expedites the program implementation deadlines in the Control Room Management/Human Factors regulations in order to realize the safety benefits sooner than established in the original rule. This final rule amends the program implementation deadlines for different procedures to no later than October 21, 2011, and August 1, 2012.

PEF owns one hazardous liquid pipeline that is subject to the new regulation and must comply with the new requirements for the Bartow/Anclote 14-inch hot oil pipeline, extending 33.3 miles from the Company's Bartow Plant north of St. Petersburg to the Anclote Plant in Holiday.

Project Accomplishments:

PEF has developed pipeline control room management procedures and trained Pipeline Terminal Operators on said procedures. PEF has also commenced design and development of a high fidelity pipeline operations simulator to be used to train Pipeline Terminal Operators. PEF completed the second In Line Inspection (Smart Pig) in late 2009. Smart pig data validation, corrosion rate calculations, anomaly ranking, repair planning, inspection interval determination, risk analysis updates, spill consequence updates, data alignment, and biennial review activities have been initiated and are ongoing. Since mid-2010 PEF has completed repairs and validations based on the Smart Pig findings. These findings included a 180 day repair that was completed along with several risk reduction projects. Risk reduction coordination is ongoing for third party projects at U.S. Highway 19 and Haines Bayshore Road, 9th Street and Gandy Boulevard, 118th Avenue, Dump Road, Progress Energy Trail, and Spruce Street. In June 2011, a sinkhole opened up in close proximity to the pipeline. Geotechnical testing was undertaken along a two mile length of the pipeline that is located in an active sinkhole

Project Fiscal Expenditures:
January 1, 2011 to December 31, 2011: O&M project expenditures are estimated to be in line with projected expenditures. Capital expenditures are estimated to be approximately $5 thousand higher than projected.

Project Progress Summary:

Ongoing smart pig anomaly evaluation, data validation, corrosion rate calculations, repair ranking, repair implementation, program biennial review activities, and third party project coordination continue. This compliance work will continue through the end of 2012 and into the future. PEF is in the process of developing pipeline control room management procedures and should meet the initial implementation date of October 21, 2011.

Project Projections:
For the period January 2012 through December 2012, O&M expenditures are expected to be $1.5 million. There are no expected capital expenditures.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI EXHIBIT 21
PARTY PROGRESS ENERGY FLORIDA
DESCRIPTION PATRICIA Q. WEST (TGF-3)
DATE 11/01/11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
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Description and Progress Report for
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Project Title: **Above Ground Storage Tank Secondary Containment**
Project No. 4

Project Description:
Florida Department of Environmental Protection Rule 62-761.510(3) states that the Company is required to make improvements to many of its above ground petroleum storage tanks in order to comply with those provisions. Subsection (d) of that rule requires all internally lined single bottom above ground storage tanks to be upgraded with secondary containment, including secondary containment for piping in contact with the soil. Rule 62-761.500(1)(e) also requires that dike field area containment for pre-1998 tanks be upgraded, if needed, to comply with the requirement.

Project Accomplishments:
PEF has completed work at: DeBary 1, Turner 7, Turner 8, Higgins 1, and Bartow 6 as well as Turner P-1 and P-2 piping work. DeBary 2 will be completed in 2011.

Project Fiscal Expenditures:
January 1, 2011 to December 31, 2011: There are no projected O&M project expenditures for this project in 2011. Capital expenditures are projected to be $1.7 million.

Project Progress Summary:
PEF will continually evaluate its compliance program, including project prioritization, schedule, and technology applications.

Project Projections:
PEF projects no expenditures in 2012 related to this program.

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Project Title: **Phase II Cooling Water Intake**
Project No. 6

Project Description:

Section 316(b) of the Federal Clean Water Act, requires that "the location, design, construction, and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact." 33 U.S.C. Section 1326. In the past, EPA and the state regulatory agency implemented Section 316(b) on a case-by-case basis. In the new Phase II rules, EPA has established "national performance standards" for determining compliance with Section 316(b) at certain existing electric generating facilities. See 40 CFR 125.94(b). The process of compliance involves planning and scheduling efforts, conducting certain biological studies, and evaluation of options for compliance. These compliance options involve engineering measures, operational measures, restorative measures and/or cost assessment measures. See generally 40 CFR 125.94 and 125.95. The EPA is expected to final new Phase II rules in July 2012. See Ms. West's Direct Testimony for more information.

Project Accomplishments:

PEF facilities subject to EPA's new Phase II rules include Anclote, Bartow, Crystal River and Suwannee plants. Early in 2004 PEF requested competitive bids for an environmental consultant to support the development of a Compliance Strategy and Implementation Plan (CSIP); that contract was secured and the CSIP is now complete. The consultant completed a Proposals for Information Collection (PICs) for Anclote & Bartow, Crystal River, and Suwannee and they have been submitted and approved by the FDEP.

Project Fiscal Expenditures:

January 1, 2011 - December 30, 2011: Due to a federal courts vacatur of the Phase II rules, the estimated project O&M expenditures for the period January 2011 through December 2011 are projected to be $0.

Project Progress Summary:

The original baseline biological studies have been completed. Work has been suspended pending completion of additional rulemaking. EPA promulgated the proposed rule in April 2011 and final rule will be issued July 2012.

Project Projections:

Due to the vacatur, the estimated project O&M expenditures for the period January 2012 through December 2012 are projected to be $0.

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Project Title: **Arsenic Groundwater Standard**
Project No. 8

Project Description:
On January 22, 2001, the U.S. Environmental Protection Agency (USEPA) adopted a new maximum contaminant level (MCL) for arsenic in drinking water, replacing the previous standard of 0.050 mg/L (50ppb) with a new MCL of 0.010 mg/L (10ppb). Effective January 1, 2005, FDEP established the USEPA MCL as Florida's drinking water standard. See Rule 62-550, F.A.C. The new standard has implications for land application and water reuse projects in Florida because the drinking water standard has been established as the groundwater standard by Rule 62-520.420(1), F.A.C. Lowering the arsenic standard will require new analytical methods for sampling groundwater at numerous PEF sites.

Project Accomplishments:
Routine quarterly sampling of existing monitoring wells continues as required by the Industrial Wastewater Permit No. FLA016960.

Project Fiscal Expenditures:
January 1, 2011 - December 31, 2011: PEF is not expecting to spend any dollars on this project in 2011. This is a reduction from the projected capital expenditures of approximately $15 thousand. This variance is mainly attributable to the status of PEF's work on this program. Analytical data has been submitted to FDEP and we are awaiting determination of next steps associated with assessing groundwater quality at the Crystal River Energy Complex.

Project Progress Summary:
PEF will continually evaluate analytical results and maintain ongoing communication with FDEP.

Project Projections:
PEF expects no expenditures for this project in 2012.

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Project Title: **Underground Storage Tanks**
Project No. 10

Project Description:
FDEP rules require that underground pollutant storage tanks and small diameter piping be upgraded with secondary containment by December 31, 2009. See Rule 62-761.510(5), F.A.C. PEF has identified four tanks that must comply with this rule: two at the Crystal River power plant and two at the Bartow power plant.

Project Accomplishments:
Work on Crystal River and Bartow USTs was completed in the fourth quarter 2006.

Project Fiscal Expenditures:
January 1, 2011 to December 31, 2011: $0 was projected to be spent in 2011.

Project Projections:
PEF expects no expenditures for this project in 2012.

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Project Title: **Modular Cooling Towers**
Project No. 11

Project Description:
The project involves installation and operation of modular cooling towers in the summer months to minimize "de-rates" of PEF's Crystal River Units 1 and 2 necessary to comply with the NPDES permit limit for the temperature of cooling water discharged from the units.

Project Accomplishments:
Vendors of modular cooling towers were evaluated regarding cost of installation and operation. The Florida Department of Environmental Protection reviewed the project and approved operation. A vendor was selected and the towers were installed during the second quarter of 2006.

Project Fiscal Expenditures:

January 1, 2011 to December 31, 2011: Project O&M costs are expected to be in line with projections.

Project Progress Summary:
Modular cooling towers began operation in June 2006 and have successfully minimized de-rates of Units 1 and 2. They will be removed in 2011.

Project Projections:
PEF projects no expenditures in 2012 related to this program.

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Project Title: **Crystal River Thermal Discharge Compliance Project**
Project No. 11.1

Project Description:
This project will evaluate and implement the best long term solution to maintain compliance with the thermal discharge limit in FDEP industrial wastewater permit for Crystal River 1, 2 & 3 that is currently being addressed in the short term by the Modular Cooling Towers approved in Docket No. 060162- EI for ECRC recovery.

Project Accomplishments:
The Study phase of the project is complete. The recommendation is to replace the modular cooling towers in coordination with the cooling solution for the CR3 Extended Power Uprate (EPU) discharge canal cooling solution. The new cooling tower associated with the CR3 EPU will be sized to mitigate both the increased temperatures from the EPU as well as serve to replace the modular cooling towers. This project will be impacted by both the final form of new environmental regulations and the repair plan and timing of completing the Crystal River Unit 3 delamination work.

Project Fiscal Expenditures:
January 1, 2011 to December 31, 2011: As can be seen in the revised 42-8E submitted as part of this filing, these estimates will be impacted by both the final form of new environmental regulations, and the repair plan and timing of completing Crystal River 3 delamination work. Accordingly, these costs cannot be accurately predicted at this time. Please see Revised schedule 42-8E attached to this Exhibit TGF-5 which shows actual costs through June for this project.

Project Progress Summary:
The design contract for the CR3 EPU cooling tower has been awarded and a cooling tower supplier has been selected.

Project Projections:
Cost estimates for this project will be impacted by both the final form of new environmental regulations, and the repair plan and timing of completing Crystal River 3 delamination work. Accordingly, these costs cannot be accurately predicted at this time.

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Project Title: **Greenhouse Gas Inventory and Reporting**
Project No. 12

Project Description:
The Greenhouse Gas (GHG) Inventory and Reporting Program was created in response to Chapter 2008-277, Florida Laws, which established the Florida Climate Protection Act, to be codified at section 403.44, Florida Statutes. Among other things, this legislation authorizes FDEP to establish a cap and trade program to GHG emissions from electric utilities. Utilities subject to the program, including PEF, will be required to use The Climate Registry for purposes of GHG emission registration and reporting.

The requirement to report to The Climate Registry was repealed during the 2010 legislative session; however, EPA's GHG Reporting Rule (40 CFR 98) does require that PEF submit 2010 GHG data to the EPA by March 31, 2011.

Project Accomplishments:
In 2009, Progress Energy joined The Climate Registry and submitted the 2008 GHG inventory data. The 2009 data was submitted during the third Quarter of 2010. Both 2008 and 2009 data was validated by a third party as required by The Climate Registry. The 2010 GHG inventory data will be submitted to EPA by September 30, 2011 and validation by a third party is not a requirement.

Project Fiscal Expenditures:
January 1, 2011 to December 31, 2011: PEF is expecting O&M expenditures to be $4,500 or 100% lower for this project than originally projected. PEF had anticipated the need for contractor support during the first year of reporting under the EPA's GHG rule due to uncertainty about use of the required data entry system. The beta version of the data entry system is now available and PEF no longer expects to need external support.

Project Progress Summary:
The 2010 GHG inventory data is currently under review and will be submitted to EPA by September 30, 2011.

Project Projections:
PEF expects no expenditures for this project in 2012.

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Project Title: **Mercury Total Daily Maximum Loads Monitoring (TMDL)**
Project No. 13

Project Description:
Section 303(d) of the federal Clean Water Act requires each state to identify state waters not meeting water quality standards and establish a TMDL for the pollutant or pollutants causing the failure to meet standards. Under a 1999 federal consent decree, TMDLs for over 100 Florida water bodies listed as impaired for mercury must be established by September 12, 2012. DEP has initiated a research program to provide the necessary information for setting the appropriate TMDLs for mercury. Among other things, the study will assess the relative contributions of mercury-emitting sources, such as coal-fired power plants, to mercury levels in surface waters.

Project Accomplishments:
Atmospheric & Environmental Research, Inc (AER) completed the literature review on mercury deposition in Florida; this document was sent to the FDEP Division of Air Resource Management and the TMDL team for review in February 2009. In addition, the Florida Electric Power Coordinating Group ("FCG") Mercury Task Force met with the FDEP Division of Air Resource Management to discuss the review in January 2010. AER performed the Florida mercury deposition modeling for the Division of Air Resource Management. The FCG Mercury Task Force contracted with Tetra Tech to conduct aquatic field sampling, including an aquatics modeling report, to develop a "Conceptual Model for the Florida Mercury TMDL." This document was finalized and submitted to the FDEP in December 2010. Key personnel from AER were employed by Environ in 2011 and FCG established a contract with Environ to ensure continuity of the project. Environ is developing a mercury atmospheric model coincidental with and based on the work of University of Michigan (working for FDEP). These modeling efforts (aquatic and atmospheric) will continue into 2011 with a final TMDL report to be submitted

Project Fiscal Expenditures:
January 1, 2011 to December 31, 2011: PEF is projecting O&M expenditures to be approximately $12 thousand or 31% higher for this project in 2011 than originally forecast. This variance is due to the need for increased contractor support for technical data assessments, primarily additional air and sediment receptor modeling, as well as additional meetings with the FDEP.

Project Progress Summary:
The project is expected to conclude in 2012.

Project Projections:
PEF expects no expenditures for this project in 2012.

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Project Title: **Hazardous Air Pollutants (HAPs) ICR Program**
Project No. 14

Project Description:

In 2009, the U.S. Environmental Protection Agency (EPA) initiated efforts to develop an Information Collection Request ("ICR"), which requires that owners/operators of all coal- and oil-fired electric utility steam generating units provide information that will allow the EPA to assess the emissions of hazardous air pollutants from each such unit. The intention of the ICR is to assist the Administrator of the EPA in developing national emission standards for hazardous air pollutants under Section 112(d) of the Clean Air Act, 42 U.S.C. 7412. Pursuant to those efforts, by letter dated December 24, 2009, the EPA formally requested that PEF comply with certain data collection and emissions testing requirements for several of its steam electric generating units. The EPA letter states that initial submittal of existing information must be made within 90 days, and that the remaining data must be submitted within 8 months. Collection and submittal of the requested information is mandatory under Section 114 of the Clean Air Act, 42 U.S.C. 7414.

Project Accomplishments:
PEF completed and submitted the ICR to EPA during 2010.

Project Fiscal Expenditures:
January 1, 2011 to December 31, 2011: PEF expects no O&M project expenditures for this year.

Project Progress Summary:
PEF completed and submitted the ICR to EPA during 2010.

Project Projections:
PEF expects no expenditures for this project in 2012.

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Project Title: **Effluent Limitation Guidelines ICR Program**
Project No. 15

Project Description:
The Effluent Limitation Guidelines ICR Program was created in response to Section 304 of the federal Clean Water Act which directs the U.S. EPA to develop and periodically review regulations, called effluent guidelines, to limit the amount of pollutants that are discharged to surface waters from various point source categories. 33 U.S.C. §13 14(b). In October 2009, EPA announced that it intended to update the effluent guidelines for the steam electric power generating point source category, which were last updated in 1982. PEF is required to complete the ICR and submit responses to U.S. EPA within 90 days. Collection and submittal of the requested information is mandatory under Section 308 of the Clean Water Act.

Project Accomplishments:
PEF completed and submitted the ICR to EPA in September 2010.

Project Fiscal Expenditures:
January 1, 2011 to December 31, 2011: PEF expects no O&M project expenditures for this year.

Project Progress Summary:
PEF completed and submitted the ICR to EPA in September 2010.

Project Projections:
PEF expects no expenditures for this project in 2012.

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Project Title: **National Pollutant Discharge Elimination System (NPDES)-Energy**
Project No. 16

Project Description:
Pursuant to the federal Clean Water Act, 33 U.S.C. § 1342, all point source discharges to navigable waters from industrial facilities must obtain permits under the NPDES Program. The Florida Department of Environmental Protection (FDEP) administers the NPDES program in Florida. PEF's Anclote, Bartow, and Crystal River North NPDES permits were issued on January 19, 2011, February 14, 2011, and July 21, 2011, respectively. Crystal River South and Suwannee plants are all in the process of renewal in 2011 and will be required to meet new permitting conditions. On March 11, 2011 PEF petitioned the Commission for approval to recover costs associated with new requirements included or expected to be included in the new renewal permits. The new activities include: thermal studies, aquatic organism return studies and implementation, whole effluent toxicity testing, dissolved oxygen studies (Bartow only), and freeboard limitation related studies (Bartow only). See Ms. West's Direct Testimony for more information.

Project Accomplishments:
PEF has begun performing thermal studies, whole effluent toxicity testing, dissolved oxygen studies and freeboard limitation related studies and evaluations to comply with new permit requirements.

Project Fiscal Expenditures:
January 1, 2011 to December 31, 2011: PEF expects that total O&M project expenditures for the year will be approximately $0.6 million.

Project Progress Summary:
PEF has begun complying with the requirements of the NPDES permits. Aquatic organism return study requirements have been postponed for a year to align with the final EPA 316(b) rule requirements (Bartow/Anclote plants). The aquatic organism return requirement is not a requirement in the Crystal River North plant NPDES permit.

Project Projections:
Estimated project expenditures for the period January 2012 through December 2012 are expected to be approximately $0.6 million in O&M costs and approximately $2.3 million in capital expenditures to ensure ongoing compliance with NPDES permits.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2012 - DECEMBER 2012
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: **Maximum Achievable Control Technology (MACT)-Energy**
Project No. 17

Project Description:
On May 24, 2011 PEF petitioned the Commission to modify the scope of its previously approved Integrated Clean Air Compliance Plan following EPA's May 3, 2011 publication of the Electric Generating Unit (EGU) National Emission Standards for Hazardous Air Pollutants (NESHAPs) that define MACT for control of hazardous air pollutant emissions. Adoption of this new rule is expected in early 2012, and will require PEF to modify its Integrated Clean Air Plan to ensure compliance with new emissions standards.

The new requirements of the proposed NESHAP and other ongoing rulemakings present significant challenges to the utility industry, requiring substantial analysis and planning to develop and implement cost-effective compliance measures. As explained in the Petition, PEF has conducted diagnostic stack testing in order to help in the development of compliance strategies. Upon issuance of the final rule, PEF expects to incur additional costs in 2012 for detailed engineering and other analyses necessary to develop compliance strategies for inclusion in an updated Integrated Clean Air Compliance Plan. See Ms. West's Direct Testimony for more info

Project Accomplishments:
PEF completed initial MACT testing at Crystal River Unit 4 in August 2011.

Project Fiscal Expenditures:
January 1, 2011 to December 31, 2011: PEF expects that total O&M project expenditures for the year will be approximately $85 thousand.

Project Progress Summary:
PEF completed initial MACT testing at Crystal River Unit 4 in August 2011.

Project Projections:
Estimated project expenditures for the period January 2012 through December 2012 are expected to be approximately $0.3 million in O&M costs to ensure compliance with the new MACT rules.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2012 - DECEMBER 2012
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: **Substation Environmental Investigation, Remediation, and Pollution Prevention**
Project No. 1

Project Description:
Chapter 376, Florida Statutes, requires that any person discharging a prohibited pollutant shall undertake to contain, remove, and abate the discharge to the satisfaction of the Florida Department of Environmental Protection. Similarly, Chapter 403, Florida Statutes provides that it is prohibited to cause pollution so as to harm or injure human health or welfare, animal, plant, or aquatic life or property. For Progress Energy Florida to continue to comply with these statutes, it is conducting environmental investigation, remediation, and pollution prevention activities associated with its substation facilities to determine the existence of pollutant discharges, and if present, their removal and remediation. Activities also include development and implementation of best management and pollution prevention measures at these facilities.

Project Accomplishments:
PEF has completed environmental remediations at 3 substations during 2011, along with ongoing remediations at several substations. Soil and groundwater sampling continue as well as remediation report writing. 230 remediations have been completed out of 279 slated for completion. PEF is continuing to work with the FDEP on remaining remediations.

Project Fiscal Expenditures:
January 1, 2011 to December 31, 2011: Project expenditures are estimated to be approximately $5.2 million higher than originally projected. This variance is primarily due to multiple sites containing more contamination than originally projected as well as scheduling conflicts that resulted in sites being rescheduled from 2010 into 2011.

Project Progress Summary:
PEF continues to remediate substation sites in accordance with the approved Substation Assessment and Remedial Action Plan.

Project Projections:
Estimated project expenditures for the period January 2012 through December 2012 are expected to be approximately $4.1 million.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI EXHIBIT 22
PARTY PROGRESS ENERGY FLORIDA
DESCRIPTION CORY ZEIGLER (TGF-3)
DATE 11/01/11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2012 - DECEMBER 2012
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: **Distribution System Environmental Investigation, Remediation, and Pollution Prevention**
Project No. 2

Project Description:
Chapter 376, Florida Statutes, requires that any person discharging a prohibited pollutant shall undertake to contain, remove, and abate the discharge to the satisfaction of the Florida Department of Environmental Protection. Similarly, Chapter 403, Florida Statutes provides that it is prohibited to cause pollution so as to harm or injure human health or welfare, animal, plant, or aquatic life or property. For Progress Energy Florida to continue to comply with these statutes, it is conducting environmental investigation, remediation, and pollution prevention activities associated with its distribution system facilities to determine the existence of pollutant discharges, and if present, their removal and remediation. Activities also include development and implementation of best management and pollution prevention measures at these facilities.

Project Accomplishments:
PEF has completed all TRIP inspections and finalized its remaining targets. PEF is expecting to complete remediations on 580 distribution padmount transformer sites in 2011. Of these 580 targets, PEF has 20 deviations sites that need to be tested to determine if further work is necessary. These sites most likely will carry over to 2012 as they are affected by other structures such as buildings. This cost for deviation sampling at these sites, $2000.00 per site, is included in 2012 estimated TRIP costs. All remediations have been conducted in accordance with the FDEP approved Environmental Remediation Strategy.

Project Fiscal Expenditures:
January 1, 2011 to December 31, 2011: Project expenditures are estimated to be approximately $0.7 million lower than originally projected.

Project Progress Summary:
This project is on schedule according to the approved Distribution System Investigation, Remediation and Pollution Prevention Program.

Project Projections:
Estimated project expenditures for the period January 2012 through December 2012 are expected to be approximately $0.3 million.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2012 - DECEMBER 2012
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: **Sea Turtle - Coastal Street Lighting**
Project No. 9

Project Description:
PEF owns and leases high pressure sodium streetlights throughout its service territory, including areas along the Florida coast. Pursuant to Section 161.163, Florida Statutes, the Florida Department of Environmental Protection (FDEP), in collaboration with the Florida Fish and Wildlife Conservation Commission (FFWCC) and the U.S. Fish & Wildlife Service (USFWS), has developed a model Sea Turtle lighting ordinance. The model ordinance is used by the local governments to develop and implement local ordinances within their jurisdiction. To date, Sea Turtle lighting ordinances have been adopted in Franklin County, Gulf County and the City of Mexico Beach in Bay County, all of which are within PEF's service territory. Since 2004, officials from the various local governments, as well as FDEP, FFWC, and USFWS, have advised PEF that lighting it owns and leases is affecting turtle nesting areas that fall within the scope of these ordinances, As a result, the local governments are requiring PEF to take additional measures to satisfy new criteria being applied to ensure compliance with the ordinances.

Project Accomplishments:
PEF continues working with Franklin County, Gulf County and the City of Mexico Beach to mitigate any potential sea turtle nesting issues by retrofitting existing street lights, placing amber shields on existing HPS street lights, and monitoring street lights for effectiveness. An additional study/test recommended by the Florida Fish & Wildlife Commission is scheduled with the University of Florida this year to test LED technology.

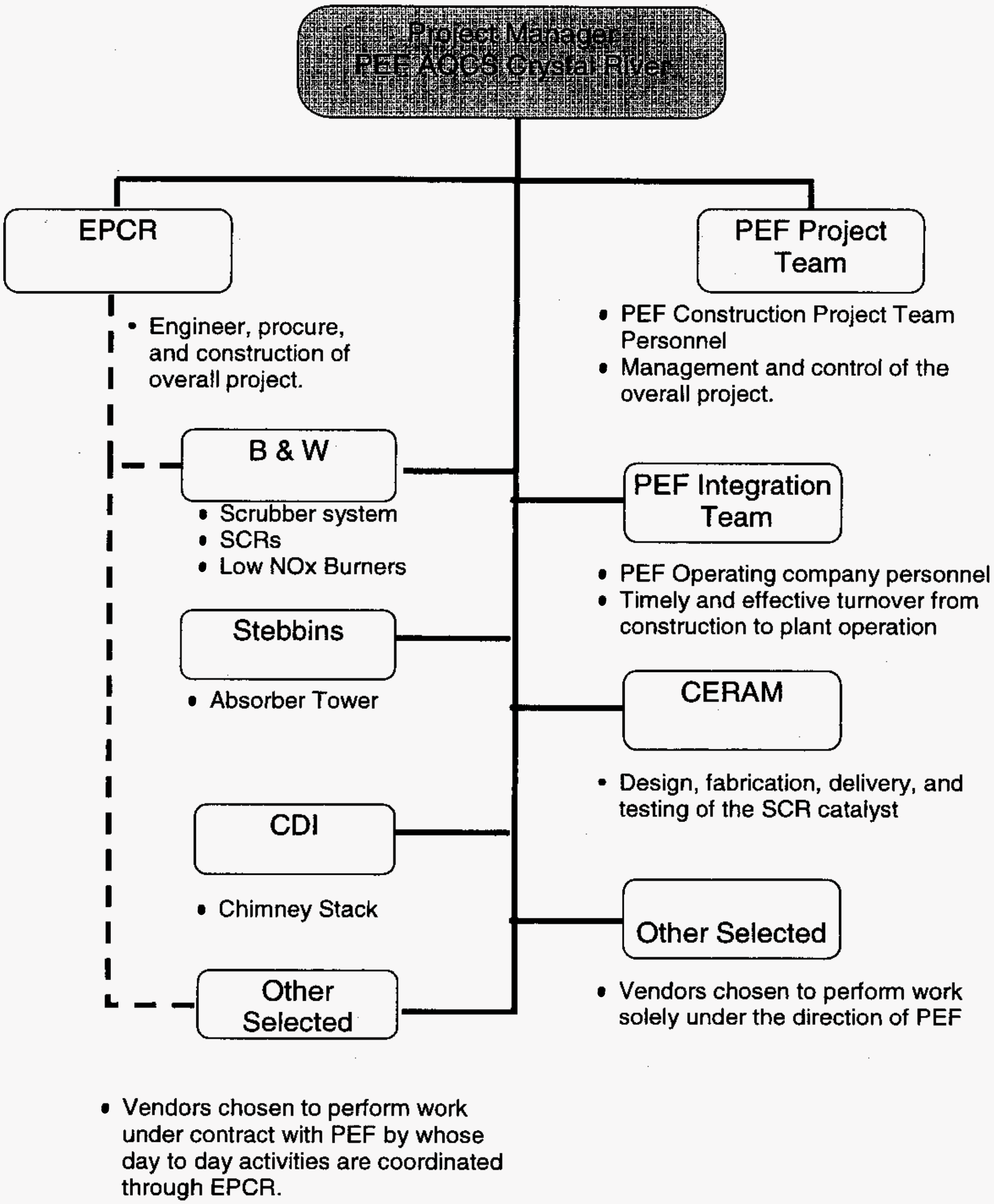
Project Fiscal Expenditures:
January 1, 2011 to December 31, 2011: O&M costs are expected to be approximately $191 higher and Capital expenditures are expected to be approximately $17 thousand lower than originally projected.

Project Progress Summary:
PEF is on schedule with the activities identified for this program.

Project Projections:
Estimated project expenditures for the period January 2012 through December 2012 are expected to be approximately $5 thousand in O&M costs and no capital expenditures to ensure ongoing compliance with sea turtle ordinances.

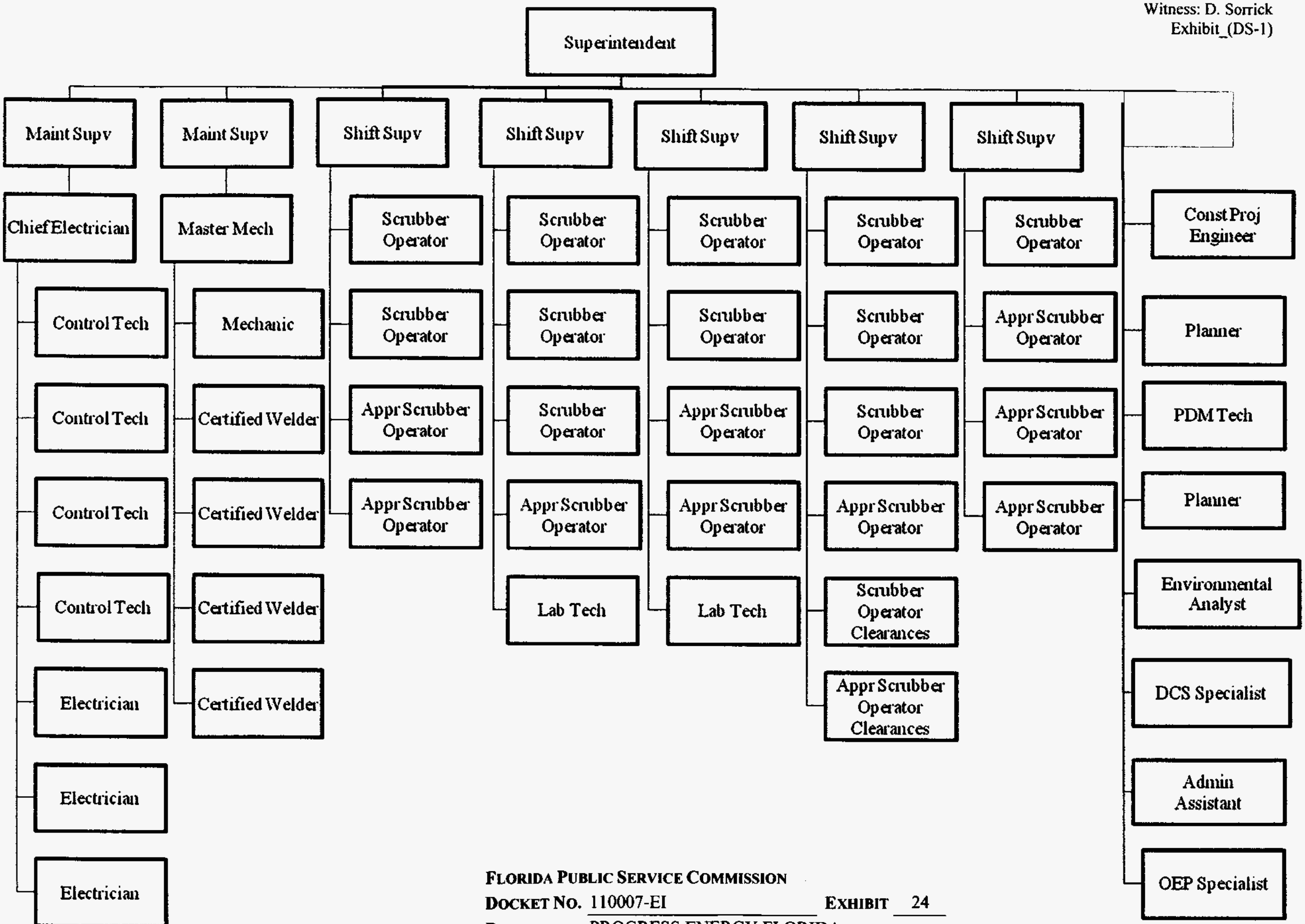
Docket No. 110007-EI
Progress Energy Florida
Witness: Kevin Murray
Exhibit No.__(KM-1)

1



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI **EXHIBIT** 23
PARTY PROGRESS ENERGY FLORIDA
DESCRIPTION KEVIN MURRAY (KM-1)
DATE 11/01/11

Witness: D. Sorrick
Exhibit_(DS-1)



FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI **EXHIBIT** 24
PARTY PROGRESS ENERGY FLORIDA
DESCRIPTION DAVID SORRICK (DS-1)
DATE 11/01/11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2012 - DECEMBER 2012
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: **Integrated Clean Air Compliance Plan (CAIR)**
Project No. 7

Project Description:
Clean Air Interstate Rule (CAIR), 40 CFR 24, 262, imposes significant new restrictions on emissions of sulfur dioxide ("SO_2") and nitrogen oxides ("NOx") from power plants in 28 eastern states, including Florida and the District of Columbia. The CAIR rule apportions region-wide SO_2 and NOx emission reduction requirements to the individual states, and further requires each affected state to revise its State Implementation Plans ("SIP") by September 2006 to include measures necessary to achieve its emission reduction budget within the prescribed deadlines.

Project Accomplishments:
During 2011, the project team focused on completing close out activities such as punch list items, demobilization and site restoration as PEF continued to transition from the construction phase of the project into the operation phase.

Project Fiscal Expenditures:
January 1, 2011 - December 31, 2011: PEF's capital expenditures for CAIR will be approximately $5.2 million higher than PEF's 2011 Projection filing. The difference is primarily attributable to work carried forward from 2010 to 2011. PEF's O&M expenditures for this project in 2011 will be approximately $0.07 million lower than projected.

Project Progress Summary:
The construction portion of the project was completed in 2010. PEF is currently in the process of transitioning to operations. PEF is currently conducting tests to replace ammonia with hydrated limestone in the Acid Mist Mitigation System. Until the transition is complete, PEF's construction team will continue to track project expenditures against the detailed project scopes to ensure that PEF receives what it contracted for and that any turnover changes are properly evaluated and documented. PEF also will continue to conduct regularly scheduled meetings with the primary contractors and senior management to maintain supervision of the project, to ensure that management remains fully informed, and to ensure that management expectations are communicated to the outside vendors and the project team.

Project Projections:
PEF expects approximately $32.1 million in O&M expenses and $27.9 approximately in capital expenditures for this program. These are discussed in further detail in the testimony of David Sorrick.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI EXHIBIT 25
PARTY PROGRESS ENERGY FLORIDA
DESCRIPTION DAVID SORRICK (TGF-3)
DATE 11/01/11

Witness: T.G. Foster
Exhibit__(TGF-1)

PROGRESS ENERGY FLORIDA, INC.
ENVIRONMENTAL COST RECOVERY
COMMISSION FORMS 42-1E THROUGH 42-9E

JANUARY 2011 - DECEMBER 2011
Calculation of the Current Period Estimated/Actual Amount
Actuals for the period of January through June 2011
Estimated for the period of July through December 2011
DOCKET NO. 110007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI EXHIBIT 26
PARTY PROGRESS ENERGY FLORIDA
DESCRIPTION THOMAS G. FOSTER (TGF-1)
DATE 11/01/11

Form 42-1E

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2011 through December 2011
(in Dollars)

Line		Period Amount
1	Over/(Under) Recovery for the Period (Form 42-2E, Line 5)	$ 2,502,602
2	Interest Provision (Form 42-2E, Line 6)	49,735
3	Sum of Current Period Adjustments (Form 42-2E, Line 10)	0
4	Current Period True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2012 to December 2012 (Lines 1 + 2 + 3)	$ 2,552,337

Form 42-2E

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2011 through December 2011

End-of-Period True-Up Amount
(in Dollars)

Line	Description		Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Estimated July 11	Estimated August 11	Estimated September 11	Estimated October 11	Estimated November 11	Estimated December 11	End of Period Total
1	ECRC Revenues (net of Revenue Taxes)		$ 15,126,181	$ 13,098,247	$ 11,705,358	$ 12,859,417	$ 15,274,316	$ 16,831,036	$ 17,299,934	$ 17,816,203	$ 17,913,485	$ 15,570,600	$ 13,804,963	$ 13,240,234	$ 180,539,974
2	True-Up Provision	38,881,686	3,240,141	3,240,141	3,240,141	3,240,141	3,240,141	3,240,141	3,240,141	3,240,141	3,240,141	3,240,141	3,240,141	3,240,140	38,881,686
3	ECRC Revenues Applicable to Period (Lines 1 + 2)		18,366,321	16,338,387	14,945,499	16,099,558	18,514,456	20,071,177	20,540,075	21,056,344	21,153,625	18,810,741	17,045,104	16,480,374	219,421,659
4	Jurisdictional ECRC Costs														
	a. O & M Activities (Form 42-5E, Line 9)		3,290,933	3,258,044	4,181,938	4,247,023	3,872,417	5,811,433	5,630,968	5,239,401	5,085,712	4,175,934	3,386,518	3,388,700	51,569,021
	b. Capital Investment Projects (Form 42-7E, Line 9)		13,896,574	13,879,845	13,856,981	13,829,335	13,804,501	13,785,996	13,763,983	13,737,814	13,720,949	13,703,061	13,690,192	13,680,806	165,350,037
	c. Total Jurisdictional ECRC Costs		17,187,507	17,137,889	18,038,919	18,076,358	17,676,918	19,597,429	19,394,951	18,977,215	18,806,661	17,878,995	17,076,710	17,069,506	216,919,058
5	Over/(Under) Recovery (Line 3 - Line 4c)		1,178,814	(799,502)	(3,093,420)	(1,976,800)	837,538	473,748	1,145,123	2,079,129	2,346,965	931,746	(31,607)	(589,132)	2,502,602
6	Interest Provision (Form 42-3E, Line 10)		9,258	8,619	6,814	4,815	3,944	3,082	2,767	2,556	2,422	2,215	1,852	1,391	49,735
7	Beginning Balance True-Up & Interest Provision (Order No. PSC-10-0683-FOF-EI)		38,881,686	36,829,617	32,798,594	26,471,847	21,259,722	18,861,064	16,097,753	14,005,503	12,847,047	11,956,293	9,650,114	6,380,218	38,881,686
	a. Deferred True-Up from January 2010 to December 2010		6,232,839	6,232,839	6,232,839	6,232,839	6,232,839	6,232,839	6,232,839	6,232,839	6,232,839	6,232,839	6,232,839	6,232,839	6,232,839
8	True-Up Collected/(Refunded) (see Line 2)		(3,240,141)	(3,240,141)	(3,240,141)	(3,240,141)	(3,240,141)	(3,240,141)	(3,240,141)	(3,240,141)	(3,240,141)	(3,240,141)	(3,240,141)	(3,240,140)	(38,881,686)
9	End of Period Total True-Up (Lines 5+6+7+7a+8)		43,062,456	39,031,433	32,704,686	27,492,561	25,093,903	22,330,592	20,238,342	19,079,886	18,189,132	15,882,953	12,613,057	8,785,176	8,785,176
10	Adjustments to Period Total True-Up Including Interest		0	0	0	0	0	0	0	0	0	0	0	0	0
11	End of Period Total True-Up (Lines 9 + 10)		$ 43,062,456	$ 39,031,433	$ 32,704,686	$ 27,492,561	$ 25,093,903	$ 22,330,592	$ 20,238,342	$ 19,079,886	$ 18,189,132	$ 15,882,953	$ 12,613,057	$ 8,785,176	$ 8,785,176

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2011 through December 2011

Interest Provision
(in Dollars)

Line	Description	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Estimated July 11	Estimated August 11	Estimated September 11	Estimated October 11	Estimated November 11	Estimated December 11	End of Period Total
1	Beginning True-Up Amount (Form 42-2E, Line 7 + 7a + 10)	$ 45,114,525	$ 43,062,456	$ 39,031,433	$ 32,704,686	$ 27,492,561	$ 25,093,903	$ 22,330,592	$ 20,238,342	$ 19,079,886	$ 18,189,132	$ 15,882,953	$ 12,613,057	
2	Ending True-Up Amount Before Interest (Line 1 + Form 42-2E, Lines 5 + 8)	43,053,198	39,022,814	32,697,872	27,487,746	25,089,959	22,327,510	20,235,575	19,077,330	18,186,710	15,880,738	12,611,205	8,783,785	
3	Total of Beginning & Ending True-Up (Lines 1 + 2)	88,167,723	82,085,270	71,729,306	60,192,432	52,582,520	47,421,413	42,566,167	39,315,672	37,266,596	34,069,870	28,494,158	21,396,843	
4	Average True-Up Amount (Line 3 x 1/2)	44,083,862	41,042,635	35,864,653	30,096,216	26,291,260	23,710,707	21,283,084	19,657,836	18,633,298	17,034,935	14,247,079	10,698,422	
5	Interest Rate (First Day of Reporting Business Month)	0.25%	0.25%	0.25%	0.20%	0.19%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	
6	Interest Rate (First Day of Subsequent Business Month)	0.25%	0.25%	0.20%	0.19%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	0.16%	
7	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	0.50%	0.50%	0.45%	0.39%	0.35%	0.32%	0.32%	0.32%	0.32%	0.32%	0.32%	0.32%	
8	Average Interest Rate (Line 7 x 1/2)	0.250%	0.250%	0.225%	0.195%	0.175%	0.160%	0.160%	0.160%	0.160%	0.160%	0.160%	0.160%	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.021%	0.021%	0.019%	0.016%	0.015%	0.013%	0.013%	0.013%	0.013%	0.013%	0.013%	0.013%	
10	Interest Provision for the Month (Line 4 x Line 9)	$ 9,258	$ 8,619	$ 6,814	$ 4,815	$ 3,944	$ 3,082	$ 2,767	$ 2,556	$ 2,422	$ 2,215	$ 1,852	$ 1,391	$ 49,735

Form 42-4E

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2011 through December 2011

Variance Report of O&M Activities
(In Dollars)

Line		(1) Estimated/ Actual	(2) Amended Projection	(3) Variance Amount	(4) Variance Percent
1	Description of O&M Activities				
	1 Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention - Demand	$ 5,009,189	$ 1,451,040	$ 3,558,149	245%
	1a Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention - Demand	3,251,741	1,616,472	1,635,269	101%
	2 Distribution System Environmental Investigation, Remediation, and Pollution Prevention - Demand	6,954,534	7,608,000	(653,466)	-9%
	3 Pipeline Integrity Management - Demand	1,592,997	1,593,000	(3)	0%
	4 Above Ground Tank Secondary Containment - Demand	0	0	0	N/A
	5 SO2 & NOx Emissions Allowances - Energy	5,642,301	5,934,929	(292,628)	-5%
	6 Phase II Cooling Water Intake - Demand	0	0	0	N/A
	6.a Phase II Cooling Water Intake 316(b) - Intm	0	0	0	N/A
	7.2 CAIR/CAMR - Peaking - Demand	121,200	131,200	(10,000)	-8%
	7.4 CAIR/CAMR Crystal River - Base	16,233,808	15,319,483	914,325	6%
	7.4 CAIR/CAMR Crystal River - Energy	12,326,703	13,270,832	(944,129)	-7%
	7.4 CAIR/CAMR Crystal River - A&G	126,258	14,851	111,407	750%
	8 Arsenic Groundwater Standard - Base - Demand	(2)	15,000	(15,002)	100%
	9 Sea Turtle - Coastal Street Lighting - Distrib - Demand	1,991	1,800	191	11%
	11 Modular Cooling Towers - Base - Demand	3,281,521	3,281,521	0	0%
	12 Greenhouse Gas Inventory and Reporting - Energy	0	4,500	(4,500)	-100%
	13 Mercury Total Daily Maximum Loads Monitoring - Energy	49,663	38,000	11,663	31%
	14 Hazardous Air Pollutants (HAPs) ICR Program - Energy	0	0	0	N/A
	15 Effluent Limitation Guidelines ICR Program - Energy	0	0	0	N/A
	16 National Pollutant Discharge Elimination System (NPDES)-Energy	648,334	0	648,334	N/A
	17 Maximum Achievable Control Technology (MACT)-Energy	85,000	0	85,000	N/A
2	Total O&M Activities - Recoverable Costs	**$ 55,325,237**	**$ 50,280,628**	**$ 5,044,609**	10%
3	Recoverable Costs Allocated to Energy	18,752,001	19,248,262	(496,261)	-3%
4	Recoverable Costs Allocated to Demand	36,573,236	31,032,367	5,540,869	18%

Notes:

Column (1) is the End of Period Totals on Form 42-5E
Column (2) = Amended Projection Form 42-2P
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Docket No. 110007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No.__(TGF-1)

Form 42-5E

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2011 through December 2011

O&M Activities
(in Dollars)

Line	Description	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Estimated July 11	Estimated August 11	Estimated September 11	Estimated October 11	Estimated November 11	Estimated December 11	End of Period Total
1	Description of O&M Activities													
	1 Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$ 546,422	$ 633,153	$ 600,196	$ 84,221	$ 623,720	$ 566,479	$ 325,833	$ 325,833	$ 325,833	$ 325,833	$ 325,833	$ 325,833	$ 5,009,189
	1a Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	486,865	221,152	443,243	578,289	117,201	374,251	171,790	171,790	171,790	171,790	171,790	171,790	3,251,741
	2 Distribution System Environmental Investigation, Remediation, and Pollution Prevention	622,226	823,044	901,921	421,788	677,391	726,364	765,400	843,600	763,800	409,000	0	0	6,954,534
	3 Pipeline Integrity Management, Review/Update Plan and Risk Assessments - Intm	91,094	178,851	18,620	41,108	75,584	57,867	188,423	188,290	188,290	188,290	188,290	188,290	1,592,997
	4 Above Ground Tank Secondary Containment - Pkg	0	0	0	0	0	0	0	0	0	0	0	0	0
	5 SO2 & NOx Emissions Allowances - Energy	336,510	152,899	247,154	652,356	671,414	691,940	681,389	687,168	567,830	332,042	388,594	233,006	5,642,301
	6 Phase II Cooling Water Intake 316(b) - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
	6a Phase II Cooling Water Intake 316(b) - Intm	0	0	0	0	0	0	0	0	0	0	0	0	0
	7.2 CAIR/CAMR - Peaking	0	22,371	2,546	0	0	0	21,783	0	4,000	16,500	33,500	20,500	121,200
	7.4 CAIR/CAMR Crystal River - Base	621,951	770,056	1,146,444	1,602,058	1,476,594	1,009,702	1,787,464	1,453,184	1,514,783	1,458,425	1,794,355	1,598,790	16,233,808
	7.4 CAIR/CAMR Crystal River - Energy	860,823	773,753	1,085,947	1,012,680	542,795	1,990,846	1,301,439	1,149,661	1,134,325	1,117,675	491,546	865,213	12,326,703
	7.4 CAIR/CAMR Crystal River - A&G	4,621	6,151	10,963	14,213	13,777	13,534	14,000	14,000	8,750	8,750	8,750	8,750	126,258
	8 Arsenic Groundwater Standard - Base	(2)	(3,312)	0	0	3,312	0	0	0	0	0	0	0	(2)
	9 Sea Turtle - Coastal Street Lighting - Distrib	15	0	0	0	1,000	0	163	163	163	163	163	163	1,991
	11 Modular Cooling Towers - Base	0	0	0	0	0	700,000	700,000	700,000	700,000	0	240,761	240,760	3,281,521
	12 Greenhouse Gas Inventory and Reporting - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	13 Mercury Total Daily Maximum Loads Monitoring - Energy	9,500	0	9,500	0	0	9,500	0	0	0	21,163	0	0	49,663
	14 Hazardous Air Pollutants (HAPs) ICR Program - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	15 Effluent Limitation Guidelines ICR Program - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	16 National Pollutant Discharge Elimination System (NPDES) - Energy	0	0	0	4,270	4,270	21,309	23,359	30,275	36,899	434,652	58,648	34,652	648,334
	17 Maximum Achievable Control Technology (MACT) - Energy	0	0	0	0	0	0	30,000	30,000	25,000	0	0	0	85,000
2	Total of O&M Activities	3,580,024	3,578,118	4,466,535	4,410,982	4,207,058	6,161,791	6,011,043	5,593,963	5,441,463	4,484,283	3,702,230	3,687,747	55,325,237
3	Recoverable Costs Allocated to Energy	1,206,833	926,652	1,342,602	1,669,306	1,218,478	2,713,595	2,036,187	1,897,104	1,764,054	1,905,532	938,788	1,132,871	18,752,001
4	Recoverable Costs Allocated to Demand - Transm	546,422	633,153	600,196	84,221	623,720	566,479	325,833	325,833	325,833	325,833	325,833	325,833	5,009,189
	Recoverable Costs Allocated to Demand - Distrib	1,109,106	1,044,196	1,345,164	1,000,077	796,593	1,100,614	937,353	1,015,553	935,753	580,953	171,953	171,953	10,208,266
	Recoverable Costs Allocated to Demand - Prod-Base	621,948	766,744	1,146,444	1,602,058	1,479,906	1,709,702	2,487,464	2,153,184	2,214,783	1,458,425	2,035,116	1,839,550	19,515,326
	Recoverable Costs Allocated to Demand - Prod-Intm	91,094	178,851	18,620	41,108	75,584	57,867	188,423	188,290	188,290	188,290	188,290	188,290	1,592,997
	Recoverable Costs Allocated to Demand - Prod-Peaking	0	22,371	2,546	0	0	0	21,783	0	4,000	16,500	33,500	20,500	121,200
	Recoverable Costs Allocated to Demand - A&G	4,621	6,151	10,963	14,213	13,777	13,534	14,000	14,000	8,750	8,750	8,750	8,750	126,258
5	Retail Energy Jurisdictional Factor	0.9601	0.9822	0.9942	0.9960	0.9893	0.9877	0.9787	0.9771	0.9770	0.9748	0.9851	0.9890	
6	Retail Transmission Demand Jurisdictional Factor	0.69516	0.69516	0.69516	0.69516	0.69516	0.69516	0.69516	0.69516	0.69516	0.69516	0.69516	0.69516	
	Retail Distribution Demand Jurisdictional Factor	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	
	Retail Production Demand Jurisdictional Factor - Base	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	
	Retail Production Demand Jurisdictional Factor - Intm	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	
	Retail Production Demand Jurisdictional Factor - Peaking	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	
	Retail Production Demand Jurisdictional Factor - A&G	0.92374	0.92374	0.92374	0.92374	0.92374	0.92374	0.92374	0.92374	0.92374	0.92374	0.92374	0.92374	
7	Jurisdictional Energy Recoverable Costs (A)	1,158,680	910,157	1,334,815	1,662,629	1,205,441	2,680,217	1,992,817	1,853,660	1,723,481	1,857,513	924,800	1,120,409	18,424,619
8	Jurisdictional Demand Recoverable Costs - Transm (B)	379,851	440,143	417,233	58,547	433,585	393,794	226,506	226,506	226,506	226,506	226,506	226,506	3,482,189
	Jurisdictional Demand Recoverable Costs - Distrib (B)	1,104,935	1,040,270	1,340,106	996,316	792,601	1,096,476	933,828	1,011,734	932,234	578,768	171,306	171,306	10,169,880
	Jurisdictional Demand Recoverable Costs - Prod-Base (B)	577,118	711,477	1,063,809	1,486,582	1,373,234	1,586,467	2,308,167	1,997,982	2,055,142	1,353,302	1,888,425	1,706,955	18,108,660
	Jurisdictional Demand Recoverable Costs - Prod-Intm (B)	66,080	129,740	13,507	29,820	54,830	41,977	136,684	136,587	136,587	136,587	136,587	136,587	1,155,573
	Jurisdictional Demand Recoverable Costs - Prod-Peaking (B)	0	20,575	2,341	0	0	0	20,034	0	3,679	15,175	30,811	18,854	111,469
	Jurisdictional Demand Recoverable Costs - A&G (B)	4,269	5,682	10,127	13,129	12,726	12,502	12,932	12,932	8,083	8,083	8,083	8,083	116,631
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 3,290,933	$ 3,258,044	$ 4,181,938	$ 4,247,023	$ 3,872,417	$ 5,811,433	$ 5,630,968	$ 5,239,401	$ 5,085,712	$ 4,175,934	$ 3,386,518	$ 3,388,700	$ 51,569,021

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

Form 42-6E

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2011 through December 2011

Variance Report of Capital Investment Activities - Recoverable Costs
(In Dollars)

Line		(1) Estimated/ Actual	(2) Amended Projection	(3) Variance Amount	(4) Variance Percent
1	Description of Capital Investment Activities				
	3.1 Pipeline Integrity Management - Bartow/Anclote Pipeline-Intermediate - Demand	$ 447,925	$ 444,388	$ 3,537	1%
	4.x Above Ground Tank Secondary Containment - Demand	1,955,440	1,884,814	70,626	4%
	5 SO2/NOx Emissions Allowances - Energy	3,165,343	3,033,957	131,386	4%
	7.x CAIR/CAMR - Demand/Energy	172,395,718	176,723,255	(4,327,536)	-2%
	9 Sea Turtle - Coastal Street Lighting -Distribution - Demand	1,480	3,583	(2,103)	-59%
	10.x Underground Storage Tanks-Base - Demand	31,599	32,092	(493)	-2%
	11 Modular Cooling Towers - Base - Demand	82,510	84,443	(1,933)	-2%
	11.1 Thermal Discharge Permanent Cooling Tower - Base - Demand	48,108	48,528	(420)	-1%
2	Total Capital Investment Activities - Recoverable Costs	**178,128,124**	**182,255,060**	**(4,126,936)**	-2%
3	Recoverable Costs Allocated to Energy	3,221,905	3,091,258	131,386	4%
4	Recoverable Costs Allocated to Demand	$ 174,906,219	$ 179,163,802	$ (4,258,322)	-2%

Notes:

Column (1) is the End of Period Totals on Form 42-7E
Column (2) = Amended Projection Form 42-3P
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Form 42-7E

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2011 through December 2011

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line	Description	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Estimated July 11	Estimated August 11	Estimated September 11	Estimated October 11	Estimated November 11	Estimated December 11	End of Period Total
1	Description of Investment Projects (A)													
	3 Pipeline Integrity Management - Bartow/Anclote Pipeline-Intermediate	$ 37,172	$ 37,100	$ 37,030	$ 36,960	$ 37,063	$ 37,298	$ 37,424	$ 37,454	$ 37,487	$ 37,519	$ 37,551	$ 37,667	$ 447,925
	4.1 Above Ground Tank Secondary Containment - Peaking	122,953	122,675	122,428	122,284	122,268	122,137	124,245	128,553	131,109	133,301	135,297	138,797	1,526,047
	4.2 Above Ground Tank Secondary Containment - Base	32,965	32,945	32,865	32,794	32,769	32,733	32,678	32,622	32,567	32,511	32,458	32,401	392,308
	4.3 Above Ground Tank Secondary Containment - Intermediate	3,117	3,112	3,108	3,102	3,098	3,093	3,088	3,083	3,079	3,073	3,068	3,064	37,085
	5 SO2/NOX Emissions Allowances - Energy	287,609	285,371	283,541	279,413	273,346	267,111	260,831	254,572	248,832	244,717	241,422	238,578	3,165,343
	7.1 CAIR/CAMR Anclote- Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0
	7.2 CAIR CT's - Peaking	21,458	21,428	21,394	21,363	21,342	21,318	21,285	21,253	21,223	21,189	21,156	21,123	255,532
	7.3 CAMR Crystal River - Base	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	31,728
	7.4 CAIR/CAMR Crystal River AFUDC - Base	14,445,526	14,423,381	14,398,017	14,372,454	14,353,568	14,339,552	14,325,156	14,308,746	14,294,176	14,277,725	14,262,668	14,250,927	172,051,896
	7.4 CAIR/CAMR Crystal River AFUDC - Energy	3,779	3,818	3,323	3,379	4,062	5,292	5,870	5,408	5,408	5,408	5,408	5,408	56,562
	9 Sea Turtle - Coastal Street Lighting -Distribution	118	118	117	117	117	116	119	123	127	131	136	141	1,480
	10.1 Underground Storage Tanks-Base	1,790	1,787	1,785	1,782	1,779	1,776	1,774	1,771	1,768	1,765	1,763	1,760	21,300
	10.2 Underground Storage Tanks-Intermediate	868	867	865	863	861	860	857	855	854	852	850	848	10,299
	11 Modular Cooling Towers - Base	12,159	12,057	11,956	11,854	11,753	11,651	8,890	438	438	438	438	438	82,510
	11.1 Thermal Discharge Permanent Cooling Tower - Base	4,035	4,030	4,026	4,020	4,016	4,011	4,007	4,002	3,997	3,993	3,988	3,983	48,108
2	Total Investment Projects - Recoverable Costs	14,976,192	14,951,332	14,923,099	14,893,029	14,868,686	14,849,592	14,828,868	14,801,525	14,783,709	14,765,266	14,748,847	14,737,979	178,128,124
3	Recoverable Costs Allocated to Energy	291,388	289,189	286,864	282,792	277,408	272,403	266,701	259,980	254,240	250,125	246,830	243,986	3,221,905
	Recoverable Costs Allocated to Demand - Distribution	118	118	117	117	117	116	119	123	127	131	136	141	1,480
4	Recoverable Costs Allocated to Demand - Production - Base	14,499,119	14,476,844	14,451,293	14,425,548	14,406,529	14,392,367	14,375,149	14,350,223	14,335,590	14,319,076	14,303,959	14,292,153	172,627,850
	Recoverable Costs Allocated to Demand - Production - Intermediate	41,157	41,079	41,003	40,925	41,022	41,251	41,369	41,392	41,420	41,444	41,469	41,779	495,309
	Recoverable Costs Allocated to Demand - Production - Peaking	144,411	144,103	143,822	143,647	143,610	143,455	145,530	149,806	152,332	154,490	156,453	159,920	1,781,579
5	Retail Energy Jurisdictional Factor	0.96010	0.98220	0.99420	0.99600	0.98930	0.98770	0.97870	0.97710	0.97700	0.97480	0.98510	0.98900	
	Retail Distribution Demand Jurisdictional Factor	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	
6	Retail Demand Jurisdictional Factor - Production - Base	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	
	Retail Demand Jurisdictional Factor - Production - Intermediate	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	
	Retail Demand Jurisdictional Factor - Production - Peaking	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	
7	Jurisdictional Energy Recoverable Costs (B)	279,761	284,041	285,200	281,661	274,439	269,053	261,020	254,027	248,393	243,822	243,152	241,302	3,165,871
	Jurisdictional Demand Recoverable Costs - Distribution (B)	117	117	117	117	117	116	119	123	127	131	135	140	1,475
8	Jurisdictional Demand Recoverable Costs - Production - Base (C)	13,454,022	13,433,353	13,409,644	13,385,755	13,368,106	13,354,965	13,338,988	13,315,859	13,302,261	13,286,957	13,272,930	13,261,975	160,184,835
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	29,856	29,799	29,744	29,687	29,758	29,924	30,010	30,026	30,046	30,064	30,082	30,307	359,302
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	132,818	132,534	132,276	132,115	132,081	131,938	133,847	137,780	140,103	142,088	143,893	147,082	1,638,554
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 13,896,574	$ 13,879,845	$ 13,856,981	$ 13,829,335	$ 13,804,501	$ 13,785,996	$ 13,763,983	$ 13,737,814	$ 13,720,949	$ 13,703,061	$ 13,690,192	$ 13,680,806	$ 165,350,037

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-8E, Line 9; Form 42-8E, Line 5 for Projects 5 - Allowances and Project 7. 4 - Reagents
(B) Line 3 x Line 5
(C) Line 4 x Line 6

Docket No. 110007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. __(TGF-1)
Page 7 of 24

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2011 through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: PIPELINE INTEGRITY MANAGEMENT - Bartow/Anclote Pipeline (Project 3.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Estimated July 11	Estimated August 11	Estimated September 11	Estimated October 11	Estimated November 11	Estimated December 11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 35,509	$ 31,260	$ 11,288	$ 11,248	$ 11,248	$ 11,248	$ 11,248	$ 11,250	$ 134,299
	b. Clearings to Plant			0	0	0	0	4,259	0	0	0	0	0	0	130,040	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		3,579,735	3,579,735	3,579,735	3,579,735	3,579,735	3,583,995	3,583,995	3,583,995	3,583,995	3,583,995	3,583,995	3,583,995	3,714,034	
3	Less: Accumulated Depreciation		(656,240)	(665,976)	(673,712)	(681,448)	(689,184)	(696,929)	(704,674)	(712,419)	(720,164)	(727,909)	(735,654)	(743,399)	(751,328)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	31,250	62,510	73,798	85,046	96,294	107,542	118,790	0	
5	Net Investment (Lines 2 + 3 + 4)		2,921,496	2,913,760	2,906,024	2,898,288	2,890,552	2,918,316	2,941,831	2,945,374	2,948,877	2,952,380	2,955,883	2,959,386	2,962,707	
6	Average Net Investment			2,917,628	2,909,892	2,902,156	2,894,420	2,904,434	2,930,074	2,943,603	2,947,126	2,950,629	2,954,132	2,957,635	2,961,047	
7	Return on Average Net Investment (B)															
	a. Equity Component Grossed Up For Taxes	8.02%		19,508	19,455	19,404	19,353	19,419	19,590	19,682	19,705	19,729	19,751	19,775	19,798	235,169
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		7,178	7,159	7,140	7,121	7,145	7,209	7,243	7,250	7,259	7,269	7,277	7,286	86,536
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			7,736	7,736	7,736	7,736	7,745	7,745	7,745	7,745	7,745	7,745	7,745	7,929	93,088
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)			2,750	2,750	2,750	2,750	2,754	2,754	2,754	2,754	2,754	2,754	2,754	2,854	33,132
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			37,172	37,100	37,030	36,960	37,063	37,298	37,424	37,454	37,487	37,519	37,551	37,867	447,925
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			37,172	37,100	37,030	36,960	37,063	37,298	37,424	37,454	37,487	37,519	37,551	37,867	447,925
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
11	Demand Jurisdictional Factor - Production (Intermediate)			0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			26,965	26,913	26,862	26,811	26,886	27,056	27,148	27,170	27,193	27,217	27,240	27,469	324,929
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$ 26,965	$ 26,913	$ 26,862	$ 26,811	$ 26,886	$ 27,056	$ 27,148	$ 27,170	$ 27,193	$ 27,217	$ 27,240	$ 27,469	$ 324,929

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Depreciation calculated in Pipeline Integrity Management section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Property tax calculated in Pipeline Integrity Managementsection of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2011 through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - PEAKING (Project 4.1)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Estimated July 11	Estimated August 11	Estimated September 11	Estimated October 11	Estimated November 11	Estimated December 11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 6,710	$ 23,150	$ 23,636	$ 9,543	$ 511,937	$ 491,215	$ 128,443	$ 411,863	$ 85,763	$ 9,373	$ 1,701,633
	b. Clearings to Plant			0	0	0	0	14,528	0	0	0	0	0	0	1,687,105	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		10,064,665	10,064,666	10,064,666	10,064,666	10,064,666	10,079,193	10,079,193	10,079,193	10,079,193	10,079,193	10,079,193	10,079,193	11,766,298	
3	Less: Accumulated Depreciation		(843,390)	(812,884)	(904,402)	(934,908)	(965,414)	(995,956)	(1,026,498)	(1,057,040)	(1,087,582)	(1,118,124)	(1,148,666)	(1,179,208)	(1,211,577)	
4	CWIP - Non-Interest Bearing		0	0	0	6,710	29,860	38,968	48,512	560,449	1,051,664	1,160,107	1,591,970	1,677,733	1	
5	Net Investment (Lines 2 + 3 + 4)		9,221,276	9,251,782	9,160,264	9,136,467	9,129,111	9,122,205	9,101,207	9,582,602	10,043,275	10,141,176	10,522,497	10,577,718	10,554,722	
6	Average Net Investment			9,236,529	9,206,023	9,148,366	9,132,789	9,125,658	9,111,706	9,341,904	9,812,938	10,092,225	10,331,836	10,550,107	10,566,220	
7	Return on Average Net Investment (B)															
	a. Equity Component Grossed Up For Taxes	8.02%		61,552	61,349	61,169	61,064	61,015	60,921	62,461	65,611	67,479	69,081	70,541	70,648	772,891
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		22,650	22,575	22,508	22,469	22,452	22,415	22,983	24,141	24,829	25,419	25,955	25,996	284,392
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			30,506	30,506	30,506	30,506	30,542	30,542	30,542	30,542	30,542	30,542	30,542	32,369	368,187
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)			8,245	8,245	8,245	8,245	8,259	8,259	8,259	8,259	8,259	8,259	8,259	9,784	100,577
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			122,953	122,675	122,428	122,284	122,268	122,137	124,245	128,553	131,109	133,301	135,297	138,797	1,526,047
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			122,953	122,675	122,428	122,284	122,268	122,137	124,245	128,553	131,109	133,301	135,297	138,797	1,526,047
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Peaking)			0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			113,082	112,827	112,599	112,467	112,452	112,332	114,271	118,233	120,584	122,600	124,435	127,654	1,403,536
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$ 113,082	$ 112,827	$ 112,599	$ 112,467	$ 112,452	$ 112,332	$ 114,271	$ 118,233	$ 120,584	$ 122,600	$ 124,435	$ 127,654	$ 1,403,536

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2011 through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Base (Project 4.2)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Estimated July 11	Estimated August 11	Estimated September 11	Estimated October 11	Estimated November 11	Estimated December 11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 7,706	$ 0	$ (3,398)	$ 0	$ 4,153	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 8,461
	b. Clearings to Plant			7,706	0	(3,398)	0	4,153	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		2,877,810	2,885,516	2,885,516	2,882,118	2,882,118	2,886,271	2,886,271	2,886,271	2,886,271	2,886,271	2,886,271	2,886,271	2,886,271	
3	Less: Accumulated Depreciation		(143,326)	(149,371)	(155,416)	(161,453)	(167,490)	(173,536)	(179,582)	(185,628)	(191,674)	(197,720)	(203,766)	(209,812)	(215,858)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+ 3 + 4)		2,734,484	2,736,146	2,730,101	2,720,666	2,714,629	2,712,735	2,706,689	2,700,643	2,694,597	2,688,551	2,682,505	2,676,459	2,670,413	
6	Average Net Investment			2,735,315	2,733,123	2,725,383	2,717,647	2,713,682	2,709,712	2,703,666	2,697,620	2,691,574	2,685,528	2,679,482	2,673,436	
7	Return on Average Net Investment (B)															
	a. Equity Component Grossed Up For Taxes	8.02%		18,289	18,274	18,222	18,171	18,144	18,117	18,077	18,037	17,996	17,955	17,916	17,875	217,073
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		6,729	6,724	6,706	6,686	6,676	6,667	6,652	6,636	6,622	6,607	6,593	6,577	79,875
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			6,045	6,045	6,037	6,037	6,046	6,046	6,046	6,046	6,046	6,046	6,046	6,046	72,532
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)			1,902	1,902	1,900	1,900	1,903	1,903	1,903	1,903	1,903	1,903	1,903	1,903	22,828
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			32,965	32,945	32,865	32,794	32,769	32,733	32,678	32,622	32,567	32,511	32,458	32,401	392,308
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			32,965	32,945	32,865	32,794	32,769	32,733	32,678	32,622	32,567	32,511	32,458	32,401	392,308
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			30,589	30,570	30,496	30,430	30,407	30,374	30,323	30,271	30,220	30,168	30,118	30,066	364,030
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$ 30,589	$ 30,570	$ 30,496	$ 30,430	$ 30,407	$ 30,374	$ 30,323	$ 30,271	$ 30,220	$ 30,168	$ 30,118	$ 30,066	$ 364,030

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI
(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 110007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No.__(TGF-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2011 through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Intermediate (Project 4.3)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Estimated July 11	Estimated August 11	Estimated September 11	Estimated October 11	Estimated November 11	Estimated December 11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	
3	Less: Accumulated Depreciation		(28,602)	(29,134)	(29,666)	(30,198)	(30,730)	(31,262)	(31,794)	(32,326)	(32,858)	(33,390)	(33,922)	(34,454)	(34,986)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2+ 3 + 4)		261,696	261,164	260,632	260,100	259,568	259,036	258,504	257,972	257,440	256,908	256,376	255,844	255,312	
6	Average Net Investment			261,430	260,898	260,366	259,834	259,302	258,770	258,238	257,706	257,174	256,642	256,110	255,578	
7	Return on Average Net Investment (B)															
	a. Equity Component Grossed Up For Taxes	8.02%		1,748	1,744	1,741	1,737	1,734	1,730	1,727	1,723	1,720	1,716	1,712	1,709	20,741
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		643	642	641	639	638	637	635	634	633	631	630	629	7,632
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			532	532	532	532	532	532	532	532	532	532	532	532	6,384
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)			194	194	194	194	194	194	194	194	194	194	194	194	2,328
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			3,117	3,112	3,108	3,102	3,098	3,093	3,088	3,083	3,079	3,073	3,068	3,064	37,085
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			3,117	3,112	3,108	3,102	3,098	3,093	3,088	3,083	3,079	3,073	3,068	3,064	37,085
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)			0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			2,261	2,257	2,255	2,250	2,247	2,244	2,240	2,236	2,234	2,229	2,226	2,223	26,902
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$ 2,261	$ 2,257	$ 2,255	$ 2,250	$ 2,247	$ 2,244	$ 2,240	$ 2,236	$ 2,234	$ 2,229	$ 2,226	$ 2,223	$ 26,902

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Depreciation calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Property tax calculated in Above Ground Tank Secondary Containment section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2011 through December 2011

Schedule of Amortization and Return
Deferred Gain on Sales of Emissions Allowances (Project 5)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Estimated July 11	Estimated August 11	Estimated September 11	Estimated October 11	Estimated November 11	Estimated December 11	End of Period Total
1	Working Capital Dr (Cr)															
	a. 1581001 SO_2 Emission Allowance Inventory		$ 5,674,079	$ 5,635,634	$ 5,624,252	$ 5,597,852	$ 5,502,899	$ 5,411,180	$ 5,328,382	$ 5,252,366	$ 5,176,776	$ 5,107,797	$ 5,065,925	$ 5,004,462	$ 4,972,187	$ 4,972,187
	b. 25401FL Auctioned SO_2 Allowance		(1,776,566)	(1,758,207)	(1,739,848)	(1,721,489)	(1,704,491)	(1,685,729)	(1,666,967)	(1,648,205)	(1,629,443)	(1,610,681)	(1,591,919)	(1,573,157)	(1,554,395)	(1,554,395)
	c. 1581002 NOx Emission Allowance Inventory (A)		27,716,427	27,399,003	27,239,127	27,000,013	26,422,640	25,824,183	25,196,280	24,572,145	23,941,805	874,317	585,385	219,492	0	0
	d. 1823403 NOx Emission Allowance Regulatory Asset				0	0	0	0	0	0	0	22,549,875	22,549,875	22,549,875	22,549,875	22,549,875
2	Total Working Capital		31,612,939	31,276,430	31,123,531	30,876,376	30,221,049	29,549,635	28,857,696	28,176,306	27,489,138	26,921,308	26,589,266	26,200,672	25,967,667	25,967,667
3	Average Net Investment			31,444,685	31,199,980	30,999,954	30,548,713	29,885,342	29,203,666	28,517,000	27,832,722	27,205,223	26,755,287	26,394,969	26,084,169	
4	Return on Average Net Working Capital Balance (B)															
	a. Equity Component Grossed Up For Taxes	8.02%		210,245	208,609	207,271	204,254	199,819	195,261	190,670	186,095	181,899	178,891	176,482	174,403	2,313,899
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		77,364	76,762	76,270	75,159	73,527	71,850	70,161	68,477	66,933	65,826	64,940	64,175	851,444
5	Total Return Component (C)			287,609	285,371	283,541	279,413	273,346	267,111	260,831	254,572	248,832	244,717	241,422	238,578	3,165,343
6	Expense Dr (Cr)															
	a. 5090001 SO2 allowance expense			38,445	11,382	26,400	94,952	91,719	82,798	76,016	75,590	68,979	41,872	61,462	32,276	701,892
	b. 4074004 Amortization Expense			(18,359)	(18,359)	(18,359)	(19,970)	(18,762)	(18,762)	(18,762)	(18,762)	(18,762)	(18,762)	(18,762)	(18,762)	(225,143)
	c. 5090003 NOx Allowance Expense			316,424	159,876	239,114	577,374	598,456	627,904	624,135	630,340	517,613	308,931	345,894	219,492	5,165,552
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
7	Net Expense (D)			336,510	152,899	247,154	652,356	671,414	691,940	681,389	687,168	567,830	332,042	388,594	233,006	5,642,301
8	Total System Recoverable Expenses (Lines 5 + 7)			624,119	438,270	530,695	931,769	944,760	959,051	942,220	941,740	816,662	576,759	630,016	471,584	8,807,644
	a. Recoverable costs allocated to Energy			624,119	438,270	530,695	931,769	944,760	959,051	942,220	941,740	816,662	576,759	630,016	471,584	8,807,644
	b. Recoverable costs allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor			0.96010	0.98220	0.99420	0.99600	0.98930	0.98770	0.97870	0.97710	0.97700	0.97480	0.98510	0.98900	
10	Demand Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Retail Energy-Related Recoverable Costs (E)			599,216	430,468	527,617	928,042	934,651	947,255	922,151	920,174	797,879	562,224	620,629	466,396	8,656,703
12	Retail Demand-Related Recoverable Costs (F)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Total Jurisdictional Recoverable Costs (Lines 11 + 12)			$ 599,216	$ 430,468	$ 527,617	$ 928,042	$ 934,651	$ 947,255	$ 922,151	$ 920,174	$ 797,879	$ 562,224	$ 620,629	$ 466,396	$ 8,656,703

Notes:
(A) As further described in the testimony of witnesses West and Foster, PEF expects the Cross-State Air Pollution Rule (CSAPR) to impact the value of NOx allowances not used in 2011. PEF is reflecting the CSAPR impact by moving this investment to a regulatory asset to be amortized into rates in 2012.
(B) Line 3 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Line 5 is reported on Capital Schedule
(D) Line 7 is reported on O&M Schedule
(E) Line 8a x Line 9.
(F) Line 8b x Line 10.

Docket No. 110007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. __(TGF-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2011 through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR - Intermediate (Project 7.1 - Anclote Low Nox Burners and SOFA)
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Estimated July 11	Estimated August 11	Estimated September 11	Estimated October 11	Estimated November 11	Estimated December 11	End of Period Total
1	Investments														
	a. Expenditures/Additions		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	0	0	0	0	0	0	0	0	0	0	0	0	0	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment (B)														
	a. Equity Component Grossed Up For Taxes 8.02%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 2.95% x 1/12) 2.95%		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation (C) 1.60%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.008000		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intm)		0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	
12	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2011 through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR - Peaking (Project 7.2 - CT Emission Monitoring Systems)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Estimated July 11	Estimated August 11	Estimated September 11	Estimated October 11	Estimated November 11	Estimated December 11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 1,708	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,708
	b. Clearings to Plant			0	0	0	0	1,708	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		1,934,400	1,934,400	1,934,400	1,934,400	1,934,400	1,936,108	1,936,108	1,936,108	1,936,108	1,936,108	1,936,108	1,936,108	1,936,108	
3	Less: Accumulated Depreciation		(133,504)	(137,044)	(140,584)	(144,124)	(147,664)	(151,208)	(154,752)	(158,296)	(161,840)	(165,384)	(168,928)	(172,472)	(176,016)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		1,800,897	1,797,357	1,793,817	1,790,277	1,786,737	1,784,901	1,781,357	1,777,813	1,774,269	1,770,725	1,767,181	1,763,637	1,760,093	
6	Average Net Investment			1,799,127	1,795,587	1,792,047	1,788,507	1,785,819	1,783,129	1,779,585	1,776,041	1,772,497	1,768,953	1,765,409	1,761,865	
7	Return on Average Net Investment (B)															
	a. Equity Component Grossed Up For Taxes	8.02%		12,028	12,006	11,981	11,959	11,940	11,922	11,898	11,876	11,852	11,827	11,804	11,780	142,873
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		4,426	4,418	4,409	4,400	4,393	4,387	4,378	4,368	4,362	4,353	4,343	4,334	52,571
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)			3,540	3,540	3,540	3,540	3,544	3,544	3,544	3,544	3,544	3,544	3,544	3,544	42,512
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)			1,464	1,464	1,464	1,464	1,465	1,465	1,465	1,465	1,465	1,465	1,465	1,465	17,576
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			21,458	21,428	21,394	21,363	21,342	21,318	21,285	21,253	21,223	21,189	21,156	21,123	255,532
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			21,458	21,428	21,394	21,363	21,342	21,318	21,285	21,253	21,223	21,189	21,156	21,123	255,532
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Peaking)			0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			19,735	19,708	19,676	19,648	19,629	19,607	19,576	19,547	19,519	19,488	19,458	19,427	235,018
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$ 19,735	$ 19,708	$ 19,676	$ 19,648	$ 19,629	$ 19,607	$ 19,576	$ 19,547	$ 19,519	$ 19,488	$ 19,458	$ 19,427	$ 235,018

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Depreciation calculated in CAIR CTs section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Property tax calculated in CAIR CTs section of Capital Program Detail file only on assets placed inservice. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 110007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. __(TGF-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2011 through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: CAMR - Crystal River - Base (Project 7.3 - Continuous Mercury Monitoring Systems)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Estimated July 11	Estimated August 11	Estimated September 11	Estimated October 11	Estimated November 11	Estimated December 11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing		289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	
5	Net Investment (Lines 2 + 3 + 4)		289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	
6	Average Net Investment			289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	289,107	
7	Return on Average Net Investment (B)															
	a. Equity Component Grossed Up For Taxes	8.02%		1,933	1,933	1,933	1,933	1,933	1,933	1,933	1,933	1,933	1,933	1,933	1,933	23,196
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		711	711	711	711	711	711	711	711	711	711	711	711	8,532
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C) 2.10%			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.007910			0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	31,728
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	31,728
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	2,453	29,441
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$ 2,453	$ 2,453	$ 2,453	$ 2,453	$ 2,453	$ 2,453	$ 2,453	$ 2,453	$ 2,453	$ 2,453	$ 2,453	$ 2,453	$ 29,441

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2011 through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR - Base - AFUDC (Project 7.4 - Crystal River FGD and SCR)
(In Dollars)

Line	Description		Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Estimated July 11	Estimated August 11	Estimated September 11	Estimated October 11	Estimated November 11	Estimated December 11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 906,482	$ (378,850)	$ (17,178)	$ (268,881)	$ 826,060	$ 790,589	$ 751,387	$ 506,022	$ 637,513	$ 447,109	$ 915,740	$ 1,491,824	$ 6,607,814
	b. Clearings to Plant			542,977	(427,874)	(61,081)	(319,027)	711,087	737,537	705,553	460,189	2,170,804	397,109	808,807	278,757	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	0
2	Plant-in-Service/Depreciation Base		1,242,647,327	1,243,190,303	1,242,762,429	1,242,701,348	1,242,382,321	1,243,093,409	1,243,830,946	1,244,536,499	1,244,996,688	1,247,167,491	1,247,564,600	1,248,373,407	1,248,652,163	
3	Less: Accumulated Depreciation		(32,451,621)	(35,009,075)	(37,565,638)	(40,122,073)	(42,677,844)	(45,235,092)	(47,793,840)	(50,354,087)	(52,915,293)	(55,478,703)	(58,043,896)	(60,610,736)	(63,178,120)	
4	CWIP - AFUDC-Non Interest Bearing		777,023	1,140,527	1,189,551	1,233,453	1,283,599	1,398,571	1,451,623	1,497,456	1,543,290	9,999	59,999	166,932	1,379,999	6,607,814
5	Net Investment (Lines 2 + 3 + 4)		1,210,972,728	1,209,321,755	1,206,386,342	1,203,812,729	1,200,988,076	1,199,256,888	1,197,488,728	1,195,679,868	1,193,624,684	1,191,698,788	1,189,580,704	1,187,929,603	1,186,854,043	
6	Average Net Investment (B)			1,210,147,241	1,207,854,049	1,205,099,535	1,202,400,401	1,200,122,481	1,198,372,808	1,196,584,297	1,194,652,276	1,192,661,735	1,190,639,745	1,188,755,153	1,187,391,821	
7	Return on Average Net Investment (C)															
	a. Equity Component Grossed Up For Taxes	8.02%		8,091,261	8,075,930	8,057,515	8,039,466	8,024,235	8,012,539	8,000,578	7,987,661	7,974,354	7,960,833	7,948,233	7,939,117	96,111,722
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		2,977,341	2,971,699	2,964,920	2,958,280	2,952,678	2,948,372	2,943,974	2,939,217	2,934,320	2,929,346	2,924,708	2,921,355	35,366,210
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (D)			2,557,454	2,556,563	2,556,435	2,555,771	2,557,248	2,558,748	2,560,247	2,561,206	2,563,410	2,565,193	2,566,840	2,567,384	30,726,499
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (E)			819,470	819,189	819,147	818,937	819,407	819,893	820,357	820,662	822,092	822,353	822,887	823,071	9,847,465
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			14,445,526	14,423,381	14,398,017	14,372,454	14,353,568	14,339,552	14,325,156	14,308,746	14,294,176	14,277,725	14,262,668	14,250,927	172,051,896
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			14,445,526	14,423,381	14,398,017	14,372,454	14,353,568	14,339,552	14,325,156	14,308,746	14,294,176	14,277,725	14,262,668	14,250,927	172,051,896
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	
12	Retail Energy-Related Recoverable Costs (F)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (G)			13,404,292	13,383,744	13,360,208	13,336,488	13,318,963	13,305,957	13,292,599	13,277,372	13,263,852	13,248,587	13,234,615	13,223,720	159,650,395
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$ 13,404,292	$ 13,383,744	$ 13,360,208	$ 13,336,488	$ 13,318,963	$ 13,305,957	$ 13,292,599	$ 13,277,372	$ 13,263,852	$ 13,248,587	$ 13,234,615	$ 13,223,720	$ 159,650,395

Notes:
NOTE 1 Prior to Oct 2010, AFUDC was calculated on all CAIR projects. As of Oct 2010, AFUDC is determined on a project by project basis. Consequently, the Net Investment Line 5 calculation includes CWIP as it is non-AFUDC interest bearing. AFUDC is not being earned on CAIR projects comprising this total.

(A) AFUDC rate reflected within Docket 100134-EI per Order PSC-10-0604-PAA-EI
(B) Line represents the Average Net Investment excluding AFUDC interest-bearing CWIP projects – see NOTE 1. Refer to Capital Program Detail for Average Net Investment Return on which Line 7 is calculated.
(C) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(D) Depreciation calculated only on assets placed in-service which appear in CAIR Crystal River section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(E) Property taxes calculated only on assets placed in-service which appear in CAIR Crystal River section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2009 Effective Tax Rate on original cost.
(F) Line 9a x Line 10
(G) Line 9b x Line 11

Docket No. 110007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. __(TGF-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2011 through December 2011

Schedule of Amortization and Return
For Project: CAIR - Energy (Project 7.4 - Reagents and By-products)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Estimated July 11	Estimated August 11	Estimated September 11	Estimated October 11	Estimated November 11	Estimated December 11	End of Period Total
1	Working Capital Dr (Cr)															
	a. 1544001 Ammonia Inventory		$ 50,759	$ 15,165	$ 27,675	$ 11,578	$ 43,583	$ 30,411	$ 71,491	$ 41,276	$ 41,276	$ 41,276	$ 41,276	$ 41,276	$ 41,276	$ 41,276
	b. 1544004 Limestone Inventory		351,659	408,637	383,343	304,085	379,549	434,565	620,752	550,000	550,000	550,000	550,000	550,000	550,000	550,000
2	Total Working Capital		402,418	423,802	411,018	315,663	423,132	464,977	692,243	591,276	591,276	591,276	591,276	591,276	591,276	591,276
3	Average Net Investment			413,110	417,410	363,340	369,398	444,054	578,610	641,760	591,276	591,276	591,276	591,276	591,276	
4	Return on Average Net Working Capital Balance (A)															
	a. Equity Component Grossed Up For Taxes	8.02%		2,762	2,791	2,429	2,470	2,969	3,869	4,291	3,953	3,953	3,953	3,953	3,953	41,348
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		1,016	1,027	894	909	1,093	1,424	1,579	1,455	1,455	1,455	1,455	1,455	15,215
5	Total Return Component (B)			3,779	3,818	3,323	3,379	4,062	5,292	5,870	5,408	5,408	5,408	5,408	5,408	56,562
6	Expense Dr (Cr)															
	a. 5020011 Ammonia expense			386,148	272,242	329,813	331,400	303,028	365,735	283,488	284,753	259,983	249,223	146,852	242,673	3,455,337
	b. 5020012 Limestone Expense			347,063	280,410	306,652	294,359	321,811	303,283	481,451	426,171	428,346	426,988	253,027	423,520	4,273,069
	c. 5020013 Dibasic Acid Expense			0	0	0	0	0	0	0	0	0	0	0	0	0
	d. 5020003 Gypsum Disposal/Sale			127,623	221,100	406,513	357,711	(82,572)	1,313,296	539,835	422,070	429,330	424,798	75,000	182,354	4,417,058
	e. 0520014 Bottom/Fly Ash Reagents Expense			0	0	42,969	29,210	528	8,532	16,667	16,667	16,667	16,667	16,667	16,667	181,239
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
7	Net Expense (C)			860,823	773,753	1,085,947	1,012,680	542,795	1,990,846	1,301,439	1,149,661	1,134,325	1,117,675	491,546	865,213	12,326,703
8	Total System Recoverable Expenses (Lines 5 + 7)			864,602	777,571	1,089,270	1,016,059	546,856	1,996,138	1,307,309	1,155,069	1,139,733	1,123,083	496,954	870,621	12,383,266
	a. Recoverable costs allocated to Energy			864,602	777,571	1,089,270	1,016,059	546,856	1,996,138	1,307,309	1,155,069	1,139,733	1,123,083	496,954	870,621	12,383,266
	b. Recoverable costs allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor			0.96010	0.98220	0.99420	0.99600	0.98630	0.98770	0.97870	0.97710	0.97700	0.97480	0.98510	0.98900	
10	Demand Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Retail Energy-Related Recoverable Costs (D)			830,104	763,730	1,082,953	1,011,994	541,005	1,971,586	1,279,463	1,128,618	1,113,519	1,094,782	489,550	861,044	12,168,348
12	Retail Demand-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Total Jurisdictional Recoverable Costs (Lines 11 + 12)			$ 830,104	$ 763,730	$ 1,082,953	$ 1,011,994	$ 541,005	$ 1,971,586	$ 1,279,463	$ 1,128,618	$ 1,113,519	$ 1,094,782	$ 489,550	$ 861,044	$ 12,168,348

Notes:
(A) Line 3 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(B) Line 5 is reported on Capital Schedule
(C) Line 7 is reported on O&M Schedule
(D) Line 8a x Line 9.
(E) Line 8b x Line 10.

Docket No. 110007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. __ (TGF-1)

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2011 through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: SEA TURTLE - COASTAL STREET LIGHTING - (Project 9)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Estimated July 11	Estimated August 11	Estimated September 11	Estimated October 11	Estimated November 11	Estimated December 11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 500	$ 500	$ 500	$ 500	$ 500	$ 500	$ 3,000
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		10,199	10,199	10,199	10,199	10,199	10,199	10,199	10,199	10,199	10,199	10,199	10,199	10,199	
3	Less: Accumulated Depreciation		(1,012)	(1,038)	(1,064)	(1,090)	(1,116)	(1,142)	(1,168)	(1,194)	(1,220)	(1,246)	(1,272)	(1,298)	(1,324)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	500	1,000	1,500	2,000	2,500	3,000	
5	Net Investment (Lines 2 + 3 + 4)		9,187	9,161	9,135	9,109	9,083	9,057	9,031	9,505	9,979	10,453	10,927	11,401	11,875	
6	Average Net Investment			9,174	9,148	9,122	9,096	9,070	9,044	9,268	9,742	10,216	10,690	11,164	11,638	
7	Return on Average Net Investment (B)															
	a. Equity Component Grossed Up For Taxes	8.02%		61	61	61	61	61	60	62	65	68	71	75	78	784
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		23	23	22	22	22	22	23	24	25	26	27	29	288
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	3.10%		26	26	26	26	26	26	26	26	26	26	26	26	312
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.009602		8	8	8	8	8	8	8	8	8	8	8	8	96
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			118	118	117	117	117	116	119	123	127	131	136	141	1,480
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			118	118	117	117	117	116	119	123	127	131	136	141	1,480
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - (Distribution)			0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			117	117	117	117	117	116	119	123	127	131	135	140	1,475
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$ 117	$ 117	$ 117	$ 117	$ 117	$ 116	$ 119	$ 123	$ 127	$ 131	$ 135	$ 140	$ 1,475

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2011 through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: UNDERGROUND STORAGE TANKS - BASE (Project 10.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Estimated July 11	Estimated August 11	Estimated September 11	Estimated October 11	Estimated November 11	Estimated December 11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	168,941	
3	Less: Accumulated Depreciation		(17,584)	(17,880)	(18,176)	(18,472)	(18,768)	(19,064)	(19,360)	(19,656)	(19,952)	(20,248)	(20,544)	(20,840)	(21,136)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		151,357	151,061	150,765	150,469	150,173	149,877	149,581	149,285	148,989	148,693	148,397	148,101	147,805	
6	Average Net Investment			151,209	150,913	150,617	150,321	150,025	149,729	149,433	149,137	148,841	148,545	148,249	147,953	
7	Return on Average Net Investment (B)															
	a. Equity Component Grossed Up For Taxes	8.02%		1,011	1,009	1,007	1,005	1,003	1,001	999	997	995	993	991	989	12,000
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		372	371	371	370	369	368	368	367	366	365	365	364	4,416
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C) 2.10%			296	296	296	296	296	296	296	296	296	296	296	296	3,552
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D) 0.007910			111	111	111	111	111	111	111	111	111	111	111	111	1,332
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,790	1,787	1,785	1,782	1,779	1,776	1,774	1,771	1,768	1,765	1,763	1,760	21,300
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			1,790	1,787	1,785	1,782	1,779	1,776	1,774	1,771	1,768	1,765	1,763	1,760	21,300
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			1,661	1,658	1,656	1,654	1,651	1,648	1,646	1,643	1,641	1,638	1,636	1,633	19,765
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$ 1,661	$ 1,658	$ 1,656	$ 1,654	$ 1,651	$ 1,648	$ 1,646	$ 1,643	$ 1,641	$ 1,638	$ 1,636	$ 1,633	$ 19,765

Notes:
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 110007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. __(TGF-1)

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2011 through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: UNDERGROUND STORAGE TANKS - INTERMEDIATE (10.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Estimated July 11	Estimated August 11	Estimated September 11	Estimated October 11	Estimated November 11	Estimated December 11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	76,006	
3	Less: Accumulated Depreciation		(9,605)	(9,808)	(10,011)	(10,214)	(10,417)	(10,620)	(10,823)	(11,026)	(11,229)	(11,432)	(11,635)	(11,838)	(12,041)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		66,401	66,198	65,995	65,792	65,589	65,386	65,183	64,980	64,777	64,574	64,371	64,168	63,965	
6	Average Net Investment			66,300	66,097	65,894	65,691	65,488	65,285	65,082	64,879	64,676	64,473	64,270	64,067	
7	Return on Average Net Investment (B)															
	a. Equity Component Grossed Up For Taxes	8.02%		443	442	441	439	438	437	435	434	432	431	430	428	5,230
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		163	163	162	162	161	161	160	160	159	159	158	158	1,925
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	3.20%		203	203	203	203	203	203	203	203	203	203	203	203	2,436
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.009370		59	59	59	59	59	59	59	59	59	59	59	59	708
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			868	867	865	863	861	860	857	855	854	852	850	848	10,299
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			868	867	865	863	861	860	857	855	854	852	850	848	10,299
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Intermediate)			0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			630	629	627	626	625	624	622	621	619	618	616	615	7,471
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$ 630	$ 629	$ 627	$ 626	$ 625	$ 624	$ 622	$ 621	$ 619	$ 618	$ 616	$ 615	$ 7,471

Notes
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI ..
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 110007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. __(TGF-1)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2011 through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: MODULAR COOLING TOWERS - BASE (Project 11)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Estimated July 11	Estimated August 11	Estimated September 11	Estimated October 11	Estimated November 11	Estimated December 11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	665,141	
3	Less: Accumulated Depreciation		(590,211)	(601,297)	(612,383)	(623,469)	(634,555)	(645,641)	(656,727)	(665,141)	(665,141)	(665,141)	(665,141)	(665,141)	(665,141)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		74,929	63,843	52,757	41,671	30,585	19,499	8,413	0	0	0	0	0	0	
6	Average Net Investment			69,386	58,300	47,214	36,128	25,042	13,956	4,207	0	0	0	0	0	
7	Return on Average Net Investment (B)															
	a. Equity Component Grossed Up For Taxes	8.02%		464	390	316	242	167	93	28	0	0	0	0	0	1,700
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		171	143	116	89	62	34	10	0	0	0	0	0	625
	c. Other (G)			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (C)	20.00%		11,086	11,086	11,086	11,086	11,086	11,086	8,413	0	0	0	0	0	74,929
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (D)	0.007910		438	438	438	438	438	438	438	438	438	438	438	438	5,256
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			12,159	12,057	11,956	11,854	11,753	11,651	8,890	438	438	438	438	438	82,510
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			12,159	12,057	11,956	11,854	11,753	11,651	8,890	438	438	438	438	438	82,510
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	
12	Retail Energy-Related Recoverable Costs (E)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (F)			11,282	11,188	11,094	11,000	10,906	10,811	8,249	406	406	406	406	406	76,563
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$ 11,282	$ 11,188	$ 11,094	$ 11,000	$ 10,906	$ 10,811	$ 8,249	$ 406	$ 406	$ 406	$ 406	$ 406	$ 76,563

Notes
(A) N/A
(B) Line 6 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(D) Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Docket No. 110007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. __(TGF-1)

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2011 through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Crystal River Thermal Discharge Compliance Project - AFUDC - Base (Project 11.1)
(in Dollars)

Line Description		Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Estimated July 11	Estimated August 11	Estimated September 11	Estimated October 11	Estimated November 11	Estimated December 11	End of Period Total
1 Investments															
a. Expenditures/Additions			$ (633,112)	$ 6,795	$ 308,002	$ 20,118	$ 12,435	$ 9,195	$ 23,217	$ 2,174,072	$ 2,284,255	$ 2,544,445	$ 2,700,043	$ 4,912,098	$ 14,361,562
b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other (A)			85,539	92,074	93,858	95,352	96,041	96,709	97,387	104,798	119,261	134,961	152,046	176,573	1,344,598
2 Plant-in-Service/Depreciation Base		361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	
3 Less: Accumulated Depreciation		(8,578)	(9,090)	(9,602)	(10,114)	(10,626)	(11,138)	(11,650)	(12,162)	(12,674)	(13,186)	(13,698)	(14,210)	(14,722)	
4 CWIP - AFUDC Bearing		15,421,367	14,873,794	14,972,663	15,374,523	15,489,992	15,598,468	15,704,372	15,824,975	18,103,846	20,507,361	23,186,767	26,038,856	31,127,527	
5 Net Investment (Lines 2 + 3 + 4)		15,774,525	15,226,440	15,324,796	15,726,144	15,841,102	15,949,066	16,054,458	16,174,549	18,452,907	20,855,911	23,534,804	26,386,382	31,474,541	
6 Average Net Investment (B)			352,902	352,390	351,878	351,366	350,854	350,342	349,830	349,318	348,806	348,294	347,782	347,270	
7 Return on Average Net Investment (C)															
a. Equity Component Grossed Up For Taxes	8.02%		2,360	2,356	2,353	2,349	2,346	2,342	2,339	2,336	2,332	2,329	2,325	2,322	28,089
b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		868	867	866	864	863	862	861	859	858	857	856	854	10,335
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation (D)			512	512	512	512	512	512	512	512	512	512	512	512	6,144
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes (E)			295	295	295	295	295	295	295	295	295	295	295	295	3,540
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			4,035	4,030	4,026	4,020	4,016	4,011	4,007	4,002	3,997	3,993	3,988	3,983	48,108
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			4,035	4,030	4,026	4,020	4,016	4,011	4,007	4,002	3,997	3,993	3,988	3,983	48,108
10 Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11 Demand Jurisdictional Factor - Production (Base)			0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	
12 Retail Energy-Related Recoverable Costs (F)			0	0	0	0	0	0	0	0	0	0	0	0	0
13 Retail Demand-Related Recoverable Costs (G)			3,744	3,740	3,736	3,730	3,727	3,722	3,718	3,714	3,709	3,705	3,701	3,696	44,640
14 Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$ 3,744	$ 3,740	$ 3,736	$ 3,730	$ 3,727	$ 3,722	$ 3,718	$ 3,714	$ 3,709	$ 3,705	$ 3,701	$ 3,696	$ 44,640

Notes:
(A) AFUDC rate reflected within Docket 100134-EI per Order PSC-10-0604-PAA-EI.
(B) Line represents the Average Net Investment excluding AFUDC interest-bearing CWIP projects. Refer to Capital Program Detail for Average Net Investment Return on which Line 7 is calculated.
(C) Weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(D) Depreciation calculated only on assets placed in-service which appear in CR Thermal Discharge Project section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(E) Property taxes calculated only on assets placed in-service which appear in CR Thermal Discharge Project section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost.
(F) Line 9a x Line 10
(G) Line 9b x Line 11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2011 through December 2011

Form 42-8E Appendix

Variance Report of Capital Investment Projects - Capital Expenditures
(In Dollars)

Line		(1) Estimated/ Actual	(2) Amended Projection	(3) Variance Amount	(4) Variance Percent
1	Description of Investment Projects				
3	Pipeline Integrity Management - Bartow/Anclote Pipeline-Intermediate	$ 134,299	$130,000	$ 4,299	3%
4.1	Above Ground Tank Secondary Containment - Peaking	1,701,633	0	1,701,633	N/A
4.2	Above Ground Tank Secondary Containment - Base	8,461	0	8,461	N/A
4.3	Above Ground Tank Secondary Containment - Intermediate	0	0	0	N/A
5	SO2/NOX Emissions Allowances - Energy (A)	25,967,667	24,629,290	1,338,376	5%
7.1	CAIR/CAMR Anclote- Intermediate	0	0	0	N/A
7.2	CAIR CT's - Peaking	1,708	0	1,708	N/A
7.3	CAMR Crystal River - Base	0	0	0	N/A
7.4	CAIR Crystal River AFUDC - Base	6,607,814	1,483,543	5,124,271	345%
7.4	CAIR Crystal River AFUDC - Energy (A)	591,276	526,076	65,200	12%
9	Sea Turtle - Coastal Street Lighting -Distribution	3,000	20,000	(17,000)	-85%
10.1	Underground Storage Tanks-Base	0	0	0	N/A
10.2	Underground Storage Tanks-Intermediate	0	0	0	N/A
11	Modular Cooling Towers - Base	0	0	0	N/A
11.1	Thermal Discharge Permanent Cooling Tower - Base	14,361,562	30,740,925	(16,379,363)	-53%
2	Total Investment Projects - Capital Expenditures	$ 49,377,420	$ 57,529,835	$ (8,152,415)	-14%

Notes:
(A) Working Capital

Form 42 9E

PROGRESS ENERGY FLORIDA

Environmental Cost Recovery Clause (ECRC)

Calculation of the Current Period Estimated/Actual Amount

January 2011 through December 2011

Progress Energy Florida Capital Structure and Cost Rates

Class of Capital	Retail Amount	Staff Adjusted	Ratio	Cost Rate	Weighted Cost Rate	PreTax Weighted Cost Rate
CE	$ 2,916,026	$ 2,945,782	46.74%	0.10500	4.908%	7.990%
PS	21,239	21,456	0.34%	0.04510	0.015%	0.025%
LTD	2,817,708	2,846,460	45.17%	0.06178	2.790%	2.790%
STD	41,245	41,666	0.66%	0.03720	0.025%	0.025%
CD-Active	144,119	145,590	2.31%	0.05950	0.137%	0.137%
CD-Inactive	1,457	1,472	0.02%	0.00000	0.000%	0.000%
ADIT	415,881	420,125	6.67%	0.00000	0.000%	0.000%
FAS 109	(122,914)	(124,168)	-1.97%	0.00000	0.000%	0.000%
ITC	3,857	3,896	0.06%	0.08360	0.005%	0.008%
Total	$ 6,238,618	$ 6,302,278	100.00%		7.881%	10.976%

Total Debt	2.952%	2.95%
Total Equity	4.928%	8.02%

Source: Per Staff 13-Month Average Capital Structure worksheet - Schedule 2 REVISED - handed out at 1/11/10 Rate Case Agenda - Docket No. 090079-EI

Rationale: The Company is using the currently approved capital structure and cost rates in accordance with the *2010 rate case Order* PSC-10-0131-FOF-EI.

Witness: T.G. Foster
Exhibit__(TGF-2)

PROGRESS ENERGY FLORIDA, INC.
ENVIRONMENTAL COST RECOVERY
CAPITAL PROGRAM DETAIL

JANUARY 2011 - DECEMBER 2011

DOCKET NO. 110007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI EXHIBIT 27
PARTY PROGRESS ENERGY FLORIDA
DESCRIPTION THOMAS G. FOSTER (TGF-2)
DATE 11/01/11

For Project: PIPELINE INTEGRITY MANAGEMENT - Alderman Road Fence (Project 3.1a)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ -
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	
3	Less: Accumulated Depreciation		(6,145)	(6,199)	(6,253)	(6,307)	(6,361)	(6,415)	(6,469)	(6,523)	(6,577)	(6,631)	(6,685)	(6,739)	(6,793)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		27,808	27,754	27,700	27,646	27,592	27,538	27,484	27,430	27,376	27,322	27,268	27,214	27,160	
6	Average Net Investment			27,781	27,727	27,673	27,619	27,565	27,511	27,457	27,403	27,349	27,295	27,241	27,187	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		186	185	185	185	184	184	184	183	183	182	182	182	$2,205
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		68	68	68	68	68	68	68	67	67	67	67	67	811
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.90%		54	54	54	54	54	54	54	54	54	54	54	54	648
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009219		26	26	26	26	26	26	26	26	26	26	26	26	312
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			334	333	333	333	332	332	332	330	330	329	329	329	3,976
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 334	$ 333	$ 333	$ 333	$ 332	$ 332	$ 332	$ 330	$ 330	$ 329	$ 329	$ 329	$ 3,976

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Leak Detection (Project 3.1b)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ -
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	
3	Less: Accumulated Depreciation		(590,327)	(596,048)	(601,769)	(607,490)	(613,211)	(618,932)	(624,653)	(630,374)	(636,095)	(641,816)	(647,537)	(653,258)	(658,979)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		2,050,309	2,044,588	2,038,867	2,033,146	2,027,425	2,021,704	2,015,983	2,010,262	2,004,541	1,998,820	1,993,099	1,987,378	1,981,657	
6	Average Net Investment			2,047,449	2,041,728	2,036,007	2,030,286	2,024,565	2,018,844	2,013,123	2,007,402	2,001,681	1,995,960	1,990,239	1,984,518	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		13,690	13,651	13,613	13,575	13,537	13,498	13,460	13,422	13,384	13,345	13,307	13,269	$161,751
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		5,037	5,023	5,009	4,995	4,981	4,967	4,953	4,939	4,925	4,911	4,897	4,883	59,520
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.60%		5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	68,652
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009219		2,029	2,029	2,029	2,029	2,029	2,029	2,029	2,029	2,029	2,029	2,029	2,029	24,348
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			26,477	26,424	26,372	26,320	26,268	26,215	26,163	26,111	26,059	26,006	25,954	25,902	314,271
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 26,477	$ 26,424	$ 26,372	$ 26,320	$ 26,268	$ 26,215	$ 26,163	$ 26,111	$ 26,059	$ 26,006	$ 25,954	$ 25,902	$ 314,271

Docket No. 110007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. __ (TGF-2)
Page 1 of 21

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Controls Upgrade (Project 3.1c)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 4,259	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 4,259
	b. Clearings to Plant			0	0	0	0	4,259	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		905,147	905,147	905,147	905,147	905,147	909,407	909,407	909,407	909,407	909,407	909,407	909,407	909,407	
3	Less: Accumulated Depreciation		(61,768)	(63,729)	(65,690)	(67,651)	(69,612)	(71,582)	(73,552)	(75,522)	(77,492)	(79,462)	(81,432)	(83,402)	(85,372)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		843,379	841,418	839,457	837,496	835,535	837,825	835,855	833,885	831,915	829,945	827,975	826,005	824,035	
6	Average Net Investment			842,399	840,438	838,477	836,516	836,680	836,840	834,870	832,900	830,930	828,960	826,990	825,020	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		5,632	5,619	5,606	5,593	5,594	5,586	5,582	5,569	5,556	5,543	5,529	5,516	$66,934
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		2,073	2,068	2,063	2,058	2,058	2,059	2,064	2,049	2,044	2,040	2,035	2,030	24,631
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.60%		1,961	1,961	1,961	1,961	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	23,604
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009219		695	695	695	695	699	699	699	699	699	699	699	699	8,372
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			10,361	10,343	10,325	10,307	10,321	10,323	10,306	10,287	10,269	10,252	10,233	10,215	123,541
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 10,361	$ 10,343	$ 10,325	$ 10,307	$ 10,321	$ 10,323	$ 10,306	$ 10,287	$ 10,269	$ 10,252	$ 10,233	$ 10,215	$ 123,541

For Project: PIPELINE INTEGRITY MANAGEMENT - Control Room Management (Project 3.1d)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 31,250	$ 31,260	$ 11,288	$ 11,248	$ 11,248	$ 11,248	$ 11,248	$ 11,250	$ 130,040
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	130,040	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		0	0	0	0	0	0	0	0	0	0	0	0	130,040	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	(184)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	31,250	62,510	73,798	85,046	96,294	107,542	118,790	0	
5	Net Investment (Lines 2 + 3 + 4)		0	0	0	0	0	31,250	62,510	73,798	85,046	96,294	107,542	118,790	129,856	
6	Average Net Investment			0	0	0	0	15,625	46,880	68,154	79,422	90,670	101,918	113,166	124,323	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		0	0	0	0	104	313	456	531	606	681	757	831	$4,279
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		0	0	0	0	38	115	168	195	223	251	278	306	1,574
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.40%		0	0	0	0	0	0	0	0	0	0	0	184	184
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009219		0	0	0	0	0	0	0	0	0	0	0	100	100
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			0	0	0	0	142	428	624	726	829	932	1,035	1,421	6,137
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 0	$ 0	$ 0	$ 0	$ 142	$ 428	$ 624	$ 726	$ 829	$ 932	$ 1,035	$ 1,421	$ 6,137

Docket No. 110007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. __(TGF-2)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - TURNER CTs (Project 4.1a)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1 Investments															
a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 14,528	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 14,528
b. Clearings to Plant			0	0	0	0	14,528	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		2,052,071	2,052,071	2,052,071	2,052,071	2,052,071	2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	
3 Less: Accumulated Depreciation		(96,747)	(101,834)	(106,921)	(112,008)	(117,095)	(122,218)	(127,341)	(132,464)	(137,587)	(142,710)	(147,833)	(152,956)	(158,079)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		1,955,324	1,950,238	1,945,151	1,940,064	1,934,977	1,944,381	1,939,258	1,934,135	1,929,012	1,923,889	1,918,766	1,913,643	1,908,520	
6 Average Net Investment			1,952,781	1,947,694	1,942,607	1,937,520	1,939,679	1,941,820	1,936,697	1,931,574	1,926,451	1,921,328	1,916,205	1,911,082	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		13,057	13,023	12,989	12,955	12,969	12,983	12,949	12,915	12,881	12,846	12,812	12,778	155,157
b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		4,804	4,792	4,779	4,767	4,772	4,777	4,765	4,752	4,740	4,727	4,714	4,702	57,091
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	2.98%		5,087	5,087	5,087	5,087	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	61,332
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.010850		1,855	1,855	1,855	1,855	1,869	1,869	1,869	1,869	1,869	1,869	1,869	1,869	22,372
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			24,803	24,757	24,710	24,664	24,733	24,752	24,706	24,659	24,613	24,565	24,518	24,472	295,952
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 24,803	$ 24,757	$ 24,710	$ 24,664	$ 24,733	$ 24,752	$ 24,706	$ 24,659	$ 24,613	$ 24,565	$ 24,518	$ 24,472	$ 295,952

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BARTOW CTs (Project 4.1b)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1 Investments															
a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	
3 Less: Accumulated Depreciation		(71,451)	(75,136)	(78,821)	(82,506)	(86,191)	(89,876)	(93,561)	(97,246)	(100,931)	(104,616)	(108,301)	(111,986)	(115,671)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		1,402,350	1,398,665	1,394,980	1,391,295	1,387,610	1,383,925	1,380,240	1,376,555	1,372,870	1,369,185	1,365,500	1,361,815	1,358,130	
6 Average Net Investment			1,400,508	1,396,823	1,393,138	1,389,453	1,385,768	1,382,083	1,378,398	1,374,713	1,371,028	1,367,343	1,363,658	1,359,973	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		9,364	9,339	9,315	9,290	9,265	9,241	9,216	9,192	9,167	9,142	9,118	9,093	110,742
b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		3,446	3,437	3,428	3,418	3,409	3,400	3,391	3,382	3,373	3,364	3,355	3,346	40,749
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	3.00%		3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	44,220
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.009370		1,151	1,151	1,151	1,151	1,151	1,151	1,151	1,151	1,151	1,151	1,151	1,151	13,812
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			17,646	17,612	17,579	17,544	17,510	17,477	17,443	17,410	17,376	17,342	17,309	17,275	209,523
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 17,646	$ 17,612	$ 17,579	$ 17,544	$ 17,510	$ 17,477	$ 17,443	$ 17,410	$ 17,376	$ 17,342	$ 17,309	$ 17,275	$ 209,523

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2011 through December 2011
Above Ground Tank Secondary Containment (Project 4 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 1 & 2 (Project 4.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	
3	Less: Accumulated Depreciation		(9,771)	(9,873)	(9,975)	(10,077)	(10,179)	(10,281)	(10,383)	(10,485)	(10,587)	(10,689)	(10,791)	(10,893)	(10,995)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		23,321	23,219	23,117	23,015	22,913	22,811	22,709	22,607	22,506	22,403	22,301	22,199	22,097	
6	Average Net Investment			23,270	23,168	23,066	22,964	22,862	22,760	22,658	22,556	22,454	22,352	22,250	22,148	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		156	155	154	154	153	152	151	151	150	149	149	148	1,822
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		57	57	57	56	56	56	56	55	55	55	55	54	669
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.70%		102	102	102	102	102	102	102	102	102	102	102	102	1,224
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		22	22	22	22	22	22	22	22	22	22	22	22	264
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			337	336	335	334	333	332	331	330	329	328	328	326	3,979
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 337	$ 336	$ 335	$ 334	$ 333	$ 332	$ 331	$ 330	$ 329	$ 328	$ 328	$ 326	$ 3,979

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - INTERCESSION CITY CTs (Project 4.1c)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	
3	Less: Accumulated Depreciation		(285,791)	(294,930)	(304,069)	(313,208)	(322,347)	(331,486)	(340,625)	(349,764)	(358,903)	(368,042)	(377,181)	(386,320)	(395,459)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		1,375,873	1,366,734	1,357,595	1,348,456	1,339,317	1,330,178	1,321,039	1,311,900	1,302,761	1,293,622	1,284,483	1,275,344	1,266,205	
6	Average Net Investment			1,371,304	1,362,165	1,353,026	1,343,887	1,334,748	1,325,609	1,316,470	1,307,331	1,298,192	1,289,053	1,279,914	1,270,775	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		9,169	9,108	9,047	8,985	8,924	8,863	8,802	8,741	8,680	8,619	8,558	8,497	105,993
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		3,374	3,351	3,329	3,306	3,284	3,261	3,239	3,216	3,194	3,171	3,149	3,127	39,001
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	6.60%		9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	109,668
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008880		1,230	1,230	1,230	1,230	1,230	1,230	1,230	1,230	1,230	1,230	1,230	1,230	14,760
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			22,912	22,828	22,745	22,660	22,577	22,493	22,410	22,326	22,243	22,159	22,076	21,993	269,422
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 22,912	$ 22,828	$ 22,745	$ 22,660	$ 22,577	$ 22,493	$ 22,410	$ 22,326	$ 22,243	$ 22,159	$ 22,076	$ 21,993	$ 269,422

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2011 through December 2011
Above Ground Tank Secondary Containment (Project 4 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - AVON PARK CTs (Project 4.1d)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1 Investments															
a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	
3 Less: Accumulated Depreciation		(29,753)	(30,469)	(31,185)	(31,901)	(32,617)	(33,333)	(34,049)	(34,765)	(35,481)	(36,197)	(36,913)	(37,629)	(38,345)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		149,185	148,469	147,753	147,037	146,321	145,605	144,889	144,173	143,457	142,741	142,025	141,309	140,593	
6 Average Net Investment			148,827	148,111	147,395	146,679	145,963	145,247	144,531	143,815	143,099	142,383	141,667	140,951	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		995	990	986	981	976	971	966	962	957	952	947	942	11,625
b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		366	364	363	361	359	357	356	354	352	350	349	347	4,278
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	4.80%		716	716	716	716	716	716	716	716	716	716	716	716	8,592
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.008940		133	133	133	133	133	133	133	133	133	133	133	133	1,596
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			2,210	2,203	2,198	2,191	2,184	2,177	2,171	2,165	2,158	2,151	2,145	2,138	26,091
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 2,210	$ 2,203	$ 2,198	$ 2,191	$ 2,184	$ 2,177	$ 2,171	$ 2,165	$ 2,158	$ 2,151	$ 2,145	$ 2,138	$ 26,091

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BAYBORO CTs (Project 4.1e)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1 Investments															
a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	
3 Less: Accumulated Depreciation		(67,508)	(69,334)	(71,160)	(72,986)	(74,812)	(76,638)	(78,464)	(80,290)	(82,116)	(83,942)	(85,768)	(87,594)	(89,420)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		662,787	660,961	659,135	657,309	655,483	653,657	651,831	650,005	648,179	646,353	644,527	642,701	640,875	
6 Average Net Investment			661,874	660,048	658,222	656,396	654,570	652,744	650,918	649,092	647,266	645,440	643,614	641,788	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		4,425	4,413	4,401	4,389	4,377	4,364	4,352	4,340	4,328	4,316	4,303	4,291	52,299
b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		1,628	1,624	1,619	1,615	1,610	1,606	1,601	1,597	1,592	1,588	1,583	1,579	19,242
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	3.00%		1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	21,912
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.009370		570	570	570	570	570	570	570	570	570	570	570	570	6,840
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			8,449	8,433	8,416	8,400	8,383	8,366	8,349	8,333	8,316	8,300	8,282	8,266	100,293
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 8,449	$ 8,433	$ 8,416	$ 8,400	$ 8,383	$ 8,366	$ 8,349	$ 8,333	$ 8,316	$ 8,300	$ 8,282	$ 8,266	$ 100,293

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2011 through December 2011
Above Ground Tank Secondary Containment (Project 4 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - SUWANNEE CTs (Project 4.1f)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	
3	Less: Accumulated Depreciation		(118,584)	(121,436)	(124,288)	(127,140)	(129,992)	(132,844)	(135,696)	(138,548)	(141,400)	(144,252)	(147,104)	(149,956)	(152,808)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		918,615	915,763	912,911	910,059	907,207	904,355	901,503	898,651	895,799	892,947	890,095	887,243	884,391	
6	Average Net Investment			917,189	914,337	911,485	908,633	905,781	902,929	900,077	897,225	894,373	891,521	888,669	885,817	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		6,132	6,113	6,094	6,075	6,056	6,037	6,018	5,999	5,980	5,961	5,942	5,923	72,330
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		2,257	2,250	2,243	2,236	2,229	2,221	2,214	2,207	2,200	2,193	2,186	2,179	26,615
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.30%		2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	34,224
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007670		663	663	663	663	663	663	663	663	663	663	663	663	7,956
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			11,904	11,878	11,852	11,826	11,800	11,773	11,747	11,721	11,695	11,669	11,643	11,617	141,125
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 11,904	$ 11,878	$ 11,852	$ 11,826	$ 11,800	$ 11,773	$ 11,747	$ 11,721	$ 11,695	$ 11,669	$ 11,643	$ 11,617	$ 141,125

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Debary CTs (Project 4.1g)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 6,710	$ 23,150	$ 9,108	$ 9,543	$ 511,937	$ 491,215	$ 128,443	$ 411,863	$ 85,763	$ 9,373	$ 1,687,105
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	1,687,105	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		2,394,294	2,394,294	2,394,294	2,394,294	2,394,294	2,394,294	2,394,294	2,394,294	2,394,294	2,394,294	2,394,294	2,394,294	4,081,399	
3	Less: Accumulated Depreciation		(100,278)	(105,466)	(110,654)	(115,842)	(121,030)	(126,218)	(131,406)	(136,594)	(141,782)	(146,970)	(152,158)	(157,346)	(164,361)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	6,709	29,859	38,968	48,511	560,448	1,051,663	1,180,106	1,591,969	1,677,732	0	
5	Net Investment (Lines 2 + 3 + 4)		2,294,016	2,288,828	2,283,640	2,285,161	2,303,123	2,307,044	2,311,399	2,818,148	3,304,175	3,427,430	3,834,105	3,914,680	3,917,038	
6	Average Net Investment			2,291,422	2,286,234	2,284,401	2,294,142	2,305,084	2,309,221	2,564,774	3,061,162	3,365,803	3,630,768	3,874,393	3,915,859	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		15,321	15,286	15,274	15,339	15,412	15,440	17,149	20,467	22,504	24,276	25,906	26,182	228,555
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		5,638	5,625	5,620	5,644	5,671	5,681	6,310	7,531	8,281	8,933	9,532	9,634	84,100
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.60%		5,188	5,188	5,188	5,188	5,188	5,188	5,188	5,188	5,188	5,188	5,188	7,015	64,083
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010850		2,165	2,165	2,165	2,165	2,165	2,165	2,165	2,165	2,165	2,165	2,165	3,690	27,505
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			28,312	28,264	28,247	28,338	28,436	28,474	30,812	35,351	38,138	40,562	42,790	46,521	404,243
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 28,312	$ 28,264	$ 28,247	$ 28,338	$ 28,436	$ 28,474	$ 30,812	$ 35,351	$ 38,138	$ 40,562	$ 42,790	$ 46,521	$ 404,243

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2011 through December 2011
Above Ground Tank Secondary Containment (Project 4 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - University of Florida (Project 4.1h)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	
3	Less: Accumulated Depreciation		(40,158)	(40,394)	(40,630)	(40,866)	(41,102)	(41,338)	(41,574)	(41,810)	(42,046)	(42,282)	(42,518)	(42,754)	(42,990)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		101,276	101,040	100,804	100,568	100,332	100,096	99,860	99,624	99,388	99,152	98,916	98,680	98,444	
6	Average Net Investment			101,158	100,922	100,686	100,450	100,214	99,978	99,742	99,506	99,270	99,034	98,798	98,562	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		676	675	673	672	670	668	667	665	664	662	661	659	8,012
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		249	248	248	247	247	246	245	245	244	244	243	242	2,948
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.00%		236	236	236	236	236	236	236	236	236	236	236	236	2,832
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.014400		170	170	170	170	170	170	170	170	170	170	170	170	2,040
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,331	1,329	1,327	1,325	1,323	1,320	1,318	1,316	1,314	1,312	1,310	1,307	15,832
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 1,331	$ 1,329	$ 1,327	$ 1,325	$ 1,323	$ 1,320	$ 1,318	$ 1,316	$ 1,314	$ 1,312	$ 1,310	$ 1,307	$ 15,832

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Anclote (Project 4.3)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	
3	Less: Accumulated Depreciation		(28,602)	(29,134)	(29,666)	(30,198)	(30,730)	(31,262)	(31,794)	(32,326)	(32,858)	(33,390)	(33,922)	(34,454)	(34,986)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		261,696	261,164	260,632	260,100	259,568	259,036	258,504	257,972	257,440	256,908	256,376	255,844	255,312	
6	Average Net Investment			261,430	260,898	260,366	259,834	259,302	258,770	258,238	257,706	257,174	256,642	256,110	255,578	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		1,748	1,744	1,741	1,737	1,734	1,730	1,727	1,723	1,720	1,716	1,712	1,709	20,741
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		643	642	641	639	638	637	635	634	633	631	630	629	7,632
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.20%		532	532	532	532	532	532	532	532	532	532	532	532	6,384
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008000		194	194	194	194	194	194	194	194	194	194	194	194	2,328
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			3,117	3,112	3,108	3,102	3,098	3,093	3,088	3,083	3,079	3,073	3,068	3,064	37,085
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 3,117	$ 3,112	$ 3,108	$ 3,102	$ 3,098	$ 3,093	$ 3,088	$ 3,083	$ 3,079	$ 3,073	$ 3,068	$ 3,064	$ 37,085

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - January 2011 through December 2011
Above Ground Tank Secondary Containment (Project 4 Recap)

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 4 & 5 (Project 4.2a)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1 Investments															
a. Expenditures/Additions			$ 7,706	$ 0	$ (3,398)	$ 0	$ 4,153	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 8,461
b. Clearings to Plant			7,706	0	(3,398)	0	4,153	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		2,844,718	2,852,424	2,852,424	2,849,026	2,849,026	2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	
3 Less: Accumulated Depreciation		(133,555)	(139,498)	(145,441)	(151,376)	(157,311)	(163,255)	(169,199)	(175,143)	(181,087)	(187,031)	(192,975)	(198,919)	(204,863)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		2,711,164	2,712,927	2,706,984	2,697,651	2,691,716	2,689,924	2,683,980	2,678,036	2,672,092	2,666,148	2,660,204	2,654,260	2,648,316	
6 Average Net Investment			2,712,045	2,709,955	2,702,317	2,694,683	2,690,820	2,686,952	2,681,008	2,675,064	2,669,120	2,663,176	2,657,232	2,651,288	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		18,133	18,119	18,068	18,017	17,997	17,965	17,926	17,886	17,846	17,806	17,767	17,727	215,251
b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		6,672	6,667	6,649	6,630	6,620	6,611	6,596	6,581	6,567	6,552	6,538	6,523	79,206
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	2.50%		5,943	5,943	5,935	5,935	5,944	5,944	5,944	5,944	5,944	5,944	5,944	5,944	71,308
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.007910		1,880	1,880	1,878	1,878	1,881	1,881	1,881	1,881	1,881	1,881	1,881	1,881	22,564
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			32,628	32,609	32,530	32,460	32,436	32,401	32,347	32,292	32,238	32,183	32,130	32,075	388,329
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 32,628	$ 32,609	$ 32,530	$ 32,460	$ 32,436	$ 32,401	$ 32,347	$ 32,292	$ 32,238	$ 32,183	$ 32,130	$ 32,075	$ 388,329

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Higgins (Project 4.1i)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1 Investments															
a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	
3 Less: Accumulated Depreciation		(33,120)	(34,897)	(36,674)	(38,451)	(40,228)	(42,005)	(43,782)	(45,559)	(47,336)	(49,113)	(50,890)	(52,667)	(54,444)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		361,848	360,071	358,294	356,517	354,740	352,963	351,186	349,409	347,632	345,855	344,078	342,301	340,524	
6 Average Net Investment			360,959	359,182	357,405	355,628	353,851	352,074	350,297	348,520	346,743	344,966	343,189	341,412	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		2,413	2,402	2,390	2,378	2,366	2,354	2,342	2,330	2,318	2,307	2,295	2,283	28,178
b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		888	884	879	875	871	866	862	857	853	849	844	840	10,368
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	5.40%		1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	21,324
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.009370		308	308	308	308	308	308	308	308	308	308	308	308	3,696
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			5,386	5,371	5,354	5,338	5,322	5,306	5,289	5,272	5,256	5,241	5,224	5,208	63,566
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 5,386	$ 5,371	$ 5,354	$ 5,338	$ 5,322	$ 5,306	$ 5,289	$ 5,272	$ 5,256	$ 5,241	$ 5,224	$ 5,208	$ 63,566

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - January 2011 through December 2011
CAIR CTs (Project 7.2 Recap)

For Project: CAIR CTs - AVON PARK (Project 7.2a)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1 Investments															
a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	
3 Less: Accumulated Depreciation		(9,401)	(9,805)	(10,209)	(10,613)	(11,017)	(11,421)	(11,825)	(12,229)	(12,633)	(13,037)	(13,441)	(13,845)	(14,249)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		152,353	151,949	151,545	151,141	150,737	150,333	149,929	149,525	149,121	148,717	148,313	147,909	147,505	
6 Average Net Investment			152,151	151,747	151,343	150,939	150,535	150,131	149,727	149,323	148,919	148,515	148,111	147,707	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		1,017	1,015	1,012	1,009	1,007	1,004	1,001	998	996	993	990	988	12,030
b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		374	373	372	371	370	369	368	367	366	365	364	363	4,422
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	3.00%		404	404	404	404	404	404	404	404	404	404	404	404	4,848
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.008940		121	121	121	121	121	121	121	121	121	121	121	121	1,452
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			1,916	1,913	1,909	1,905	1,902	1,898	1,894	1,890	1,887	1,883	1,879	1,876	22,752
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 1,916	$ 1,913	$ 1,909	$ 1,905	$ 1,902	$ 1,898	$ 1,894	$ 1,890	$ 1,887	$ 1,883	$ 1,879	$ 1,876	$ 22,752

For Project: CAIR CTs - BARTOW (Project 7.2b)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1 Investments															
a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	
3 Less: Accumulated Depreciation		(23,677)	(24,044)	(24,411)	(24,778)	(25,145)	(25,512)	(25,879)	(26,246)	(26,613)	(26,980)	(27,347)	(27,714)	(28,081)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		251,670	251,303	250,936	250,569	250,202	249,835	249,468	249,101	248,734	248,367	248,000	247,633	247,266	
6 Average Net Investment			251,487	251,120	250,753	250,386	250,019	249,652	249,285	248,918	248,551	248,184	247,817	247,450	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		1,681	1,679	1,677	1,674	1,672	1,669	1,667	1,664	1,662	1,659	1,657	1,654	20,015
b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		619	618	617	616	615	614	613	612	612	611	610	609	7,366
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	1.60%		367	367	367	367	367	367	367	367	367	367	367	367	4,404
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.009370		215	215	215	215	215	215	215	215	215	215	215	215	2,580
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			2,882	2,879	2,876	2,872	2,869	2,865	2,862	2,858	2,856	2,852	2,849	2,845	34,365
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 2,882	$ 2,879	$ 2,876	$ 2,872	$ 2,869	$ 2,865	$ 2,862	$ 2,858	$ 2,856	$ 2,852	$ 2,849	$ 2,845	$ 34,365

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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2011 through December 2011
CAIR CTs (Project 7.2 Recap)

For Project: CAIR CTs - BAYBORO (Project 7.2c)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	
3	Less: Accumulated Depreciation		(15,651)	(16,032)	(16,413)	(16,794)	(17,175)	(17,556)	(17,937)	(18,318)	(18,699)	(19,080)	(19,461)	(19,842)	(20,223)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		183,337	182,956	182,575	182,194	181,813	181,432	181,051	180,670	180,289	179,908	179,527	179,146	178,765	
6	Average Net Investment			183,147	182,766	182,385	182,004	181,623	181,242	180,861	180,480	180,099	179,718	179,337	178,956	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		1,225	1,222	1,219	1,217	1,214	1,212	1,209	1,207	1,204	1,202	1,199	1,197	14,527
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		451	450	449	448	447	446	445	444	443	442	441	440	5,346
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.30%		381	381	381	381	381	381	381	381	381	381	381	381	4,572
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009370		155	155	155	155	155	155	155	155	155	155	155	155	1,860
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,212	2,208	2,204	2,201	2,197	2,194	2,190	2,187	2,183	2,180	2,176	2,173	26,305
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 2,212	$ 2,208	$ 2,204	$ 2,201	$ 2,197	$ 2,194	$ 2,190	$ 2,187	$ 2,183	$ 2,180	$ 2,176	$ 2,173	$ 26,305

For Project: CAIR CTs - Debary (Project 7.2d)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	
3	Less: Accumulated Depreciation		(9,003)	(9,222)	(9,441)	(9,660)	(9,879)	(10,098)	(10,317)	(10,536)	(10,755)	(10,974)	(11,193)	(11,412)	(11,631)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		78,664	78,445	78,226	78,007	77,788	77,569	77,350	77,131	76,912	76,693	76,474	76,255	76,036	
6	Average Net Investment			78,555	78,336	78,117	77,898	77,679	77,460	77,241	77,022	76,803	76,584	76,365	76,146	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		525	524	522	521	519	518	516	515	514	512	511	509	6,206
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		193	193	192	192	191	191	190	189	189	188	188	187	2,283
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.00%		219	219	219	219	219	219	219	219	219	219	219	219	2,628
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010850		79	79	79	79	79	79	79	79	79	79	79	79	948
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,016	1,015	1,012	1,011	1,008	1,007	1,004	1,002	1,001	998	997	994	12,065
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 1,016	$ 1,015	$ 1,012	$ 1,011	$ 1,008	$ 1,007	$ 1,004	$ 1,002	$ 1,001	$ 998	$ 997	$ 994	$ 12,065

Docket No. 110007-EI
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Witness: T.G. Foster
Exhibit No. __(TGF-2)

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2011 through December 2011
CAIR CTs (Project 7.2 Recap)

For Project: CAIR CTs - HIGGINS (Project 7.2e)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1 Investments															
a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 1,708	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,708
b. Clearings to Plant			0	0	0	0	1,708	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		345,490	345,490	345,490	345,490	345,490	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	
3 Less: Accumulated Depreciation		(16,717)	(17,552)	(18,387)	(19,222)	(20,057)	(20,896)	(21,735)	(22,574)	(23,413)	(24,252)	(25,091)	(25,930)	(26,769)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		328,773	327,938	327,103	326,268	325,433	326,302	325,463	324,624	323,785	322,946	322,107	321,268	320,429	
6 Average Net Investment			328,356	327,521	326,686	325,851	325,868	325,882	325,043	324,204	323,366	322,526	321,687	320,848	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		2,195	2,190	2,184	2,179	2,179	2,179	2,173	2,168	2,162	2,156	2,151	2,145	26,061
b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		808	806	804	802	802	802	800	798	796	794	791	789	9,592
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	2.90%		835	835	835	835	839	839	839	839	839	839	839	839	10,062
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.009370		270	270	270	270	271	271	271	271	271	271	271	271	3,248
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			4,108	4,101	4,093	4,086	4,091	4,091	4,083	4,076	4,068	4,060	4,052	4,044	48,953
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 4,108	$ 4,101	$ 4,093	$ 4,086	$ 4,091	$ 4,091	$ 4,083	$ 4,076	$ 4,068	$ 4,060	$ 4,052	$ 4,044	$ 48,953

For Project: CAIR CTs - INTERCESSION CITY (Project 7.2f)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1 Investments															
a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	
3 Less: Accumulated Depreciation		(28,903)	(29,690)	(30,477)	(31,264)	(32,051)	(32,838)	(33,625)	(34,412)	(35,199)	(35,986)	(36,773)	(37,560)	(38,347)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		320,681	319,894	319,107	318,320	317,533	316,746	315,959	315,172	314,385	313,598	312,811	312,024	311,237	
6 Average Net Investment			320,287	319,500	318,713	317,926	317,139	316,352	315,565	314,778	313,991	313,204	312,417	311,630	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		2,141	2,136	2,131	2,126	2,120	2,115	2,110	2,105	2,099	2,094	2,089	2,084	25,350
b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		788	786	784	782	780	778	776	774	773	771	769	767	9,328
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	2.70%		787	787	787	787	787	787	787	787	787	787	787	787	9,444
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.008880		259	259	259	259	259	259	259	259	259	259	259	259	3,108
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			3,975	3,968	3,961	3,954	3,946	3,939	3,932	3,925	3,918	3,911	3,904	3,897	47,230
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 3,975	$ 3,968	$ 3,961	$ 3,954	$ 3,946	$ 3,939	$ 3,932	$ 3,925	$ 3,918	$ 3,911	$ 3,904	$ 3,897	$ 47,230

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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - January 2011 through December 2011
CAIR CTs (Project 7.2 Recap)

For Project: CAIR CTs - TURNER (Project 7.2g)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	
3	Less: Accumulated Depreciation		(9,375)	(9,509)	(9,643)	(9,777)	(9,911)	(10,045)	(10,179)	(10,313)	(10,447)	(10,581)	(10,715)	(10,849)	(10,983)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		124,637	124,503	124,369	124,235	124,101	123,967	123,833	123,699	123,565	123,431	123,297	123,163	123,029	
6	Average Net Investment			124,570	124,436	124,302	124,168	124,034	123,900	123,766	123,632	123,498	123,364	123,230	123,096	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		833	832	831	830	829	828	828	827	826	825	824	823	9,936
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		306	306	306	305	305	305	305	304	304	304	303	303	3,656
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.20%		134	134	134	134	134	134	134	134	134	134	134	134	1,608
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010850		121	121	121	121	121	121	121	121	121	121	121	121	1,452
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,394	1,393	1,392	1,390	1,389	1,388	1,388	1,386	1,385	1,384	1,382	1,381	16,652
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 1,394	$ 1,393	$ 1,392	$ 1,390	$ 1,389	$ 1,388	$ 1,388	$ 1,386	$ 1,385	$ 1,384	$ 1,382	$ 1,381	$ 16,652

For Project: CAIR CTs - SUWANNEE (Project 7.2h)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	
3	Less: Accumulated Depreciation		(20,778)	(21,191)	(21,604)	(22,017)	(22,430)	(22,843)	(23,256)	(23,669)	(24,082)	(24,495)	(24,908)	(25,321)	(25,734)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		360,782	360,369	359,956	359,543	359,130	358,717	358,304	357,891	357,478	357,065	356,652	356,239	355,826	
6	Average Net Investment			360,575	360,162	359,749	359,336	358,923	358,510	358,097	357,684	357,271	356,858	356,445	356,032	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		2,411	2,408	2,405	2,403	2,400	2,397	2,394	2,392	2,389	2,386	2,383	2,380	28,748
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		887	886	885	884	883	882	881	880	879	878	877	876	10,578
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.30%		413	413	413	413	413	413	413	413	413	413	413	413	4,956
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007670		244	244	244	244	244	244	244	244	244	244	244	244	2,928
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			3,955	3,951	3,947	3,944	3,940	3,936	3,932	3,929	3,925	3,921	3,917	3,913	47,210
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 3,955	$ 3,951	$ 3,947	$ 3,944	$ 3,940	$ 3,936	$ 3,932	$ 3,929	$ 3,925	$ 3,921	$ 3,917	$ 3,913	$ 47,210

Docket No. 110007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No.__(TGF-2)
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PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - January 2011 through December 2011
CAIR Crystal River (Project 7.4 Recap)

For Project: CAIR Crystal River AFUDC - Access Road and Vehicle Barrier System (Project 7.4a)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1 Investments															
a. Expenditures/Additions			$ 375,030	$ 49,024	$ 43,902	$ 41,266	$ 120,276	$ 84,565	$ 45,833	$ 45,833	$ 45,833	$ 45,833	$ 45,833	$ 45,833	$ 989,072
b. Clearings to Plant			0	0	0	0	0	0	0	0	1,589,124	45,833	45,833	45,833	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		15,381,150	15,381,150	15,381,150	15,381,150	15,381,150	15,381,150	15,381,150	15,381,150	15,381,150	16,970,273	17,016,106	17,061,940	17,107,773	
3 Less: Accumulated Depreciation		(1,092,577)	(1,111,803)	(1,131,029)	(1,150,255)	(1,169,481)	(1,188,707)	(1,207,933)	(1,227,159)	(1,246,385)	(1,266,605)	(1,287,875)	(1,309,202)	(1,330,587)	
4 CWIP - Non-Interest Bearing		737,551	1,112,590	1,161,614	1,205,516	1,246,782	1,367,058	1,451,624	1,497,457	1,543,290	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		15,026,125	15,381,937	15,411,735	15,436,411	15,458,451	15,559,501	15,624,841	15,651,448	15,678,055	15,703,669	15,728,232	15,752,738	15,777,187	
6 Average Net Investment			15,204,031	15,396,836	15,424,073	15,447,431	15,508,976	15,592,171	15,638,144	15,664,752	15,690,862	15,715,950	15,740,485	15,764,962	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		101,657	102,946	103,128	103,284	103,696	104,252	104,559	104,737	104,912	105,080	105,244	105,407	1,248,902
b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		37,407	37,881	37,948	38,008	38,157	38,362	38,475	38,540	38,604	38,666	38,727	38,787	459,560
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	1.50%		19,226	19,226	19,226	19,226	19,226	19,226	19,226	19,226	20,220	21,270	21,327	21,385	238,010
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.007910		10,139	10,139	10,139	10,139	10,139	10,139	10,139	10,139	11,166	11,216	11,247	11,277	126,038
e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			168,429	170,192	170,441	170,655	171,218	171,979	172,399	172,642	174,922	176,232	176,545	176,856	2,072,510
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 168,429	$ 170,192	$ 170,441	$ 170,655	$ 171,218	$ 171,979	$ 172,399	$ 172,642	$ 174,922	$ 176,232	$ 176,545	$ 176,856	$ 2,072,510

For Project: CAIR Crystal River AFUDC - UNIT 4 LNB/AH (Project 7.4b)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1 Investments															
a. Expenditures/Additions			$ 17,321	$ 115,117	$ (59,852)	$ (557,487)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ (484,900)
b. Clearings to Plant			17,321	115,117	(59,852)	(557,487)	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		12,859,283	12,876,604	12,991,722	12,931,870	12,374,383	12,374,383	12,374,383	12,374,383	12,374,383	12,374,383	12,374,383	12,374,383	12,374,383	
3 Less: Accumulated Depreciation		(543,544)	(570,370)	(597,436)	(624,377)	(650,157)	(675,937)	(701,717)	(727,497)	(753,277)	(779,057)	(804,837)	(830,617)	(856,397)	
4 CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5 Net Investment (Lines 2 + 3 + 4)		12,315,740	12,306,235	12,394,286	12,307,493	11,724,226	11,698,446	11,672,666	11,646,886	11,621,106	11,595,326	11,569,546	11,543,766	11,517,986	
6 Average Net Investment			12,310,987	12,350,260	12,350,889	12,015,859	11,711,336	11,685,556	11,659,776	11,633,996	11,608,216	11,582,436	11,556,656	11,530,876	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		82,313	82,576	82,580	80,340	78,304	78,132	77,959	77,787	77,615	77,442	77,270	77,098	949,416
b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		30,289	30,385	30,387	29,563	28,814	28,750	28,687	28,623	28,560	28,496	28,433	28,370	349,357
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	2.50%		26,826	27,066	26,941	25,780	25,780	25,780	25,780	25,780	25,780	25,780	25,780	25,780	312,853
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.007910		8,488	8,564	8,524	8,157	8,157	8,157	8,157	8,157	8,157	8,157	8,157	8,157	98,989
e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			147,916	148,591	148,432	143,840	141,055	140,819	140,583	140,347	140,112	139,876	139,640	139,405	1,710,615
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 147,916	$ 148,591	$ 148,432	$ 143,840	$ 141,055	$ 140,819	$ 140,583	$ 140,347	$ 140,112	$ 139,876	$ 139,640	$ 139,405	$ 1,710,615

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2011 through December 2011
CAIR Crystal River (Project 7.4 Recap)

For Project: CAIR Crystal River AFUDC - Selective Catalytic Reduction CR5 (Project 7.4c)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 92,873	$ 697,152	$ 193,816	$ (219,225)	$ 144,691	$ 87,989	$ 78,018	$ 70,859	$ 63,767	$ 64,504	$ 230,279	$ 283	$ 1,585,006
	b. Clearings to Plant			92,873	697,152	193,816	(219,225)	144,691	87,989	78,018	70,859	63,767	64,504	230,279	283	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		94,129,661	94,222,535	94,919,687	95,113,503	94,894,277	95,038,968	95,126,957	95,204,976	95,275,834	95,339,601	95,404,105	95,634,384	95,634,667	
3	Less: Accumulated Depreciation		(3,745,413)	(3,941,710)	(4,139,459)	(4,337,612)	(4,535,308)	(4,733,306)	(4,931,487)	(5,129,831)	(5,328,322)	(5,526,946)	(5,725,705)	(5,924,643)	(6,124,182)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		90,384,248	90,280,825	90,780,228	90,775,891	90,358,969	90,305,662	90,195,470	90,075,145	89,947,512	89,812,655	89,678,400	89,709,441	89,510,485	
6	Average Net Investment			90,332,536	90,530,526	90,778,059	90,567,430	90,332,316	90,250,566	90,135,307	90,011,328	89,880,084	89,745,528	89,693,921	89,609,963	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		603,980	605,303	606,959	605,550	603,978	603,432	602,661	601,832	600,955	600,055	599,710	599,148	7,233,563
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		222,246	222,733	223,342	222,824	222,248	222,045	221,761	221,456	221,133	220,802	220,675	220,469	2,661,732
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		196,297	197,749	198,153	197,696	197,998	198,181	198,344	198,491	198,624	198,759	199,238	199,239	2,378,780
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		82,108	82,568	82,698	82,551	82,647	82,705	82,756	82,803	82,845	82,887	83,039	83,039	752,644
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,084,631	1,088,353	1,091,150	1,088,621	1,086,869	1,086,363	1,085,522	1,084,582	1,083,557	1,082,503	1,082,662	1,081,895	13,026,708
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 1,084,631	$ 1,088,353	$ 1,091,150	$ 1,088,621	$ 1,086,869	$ 1,086,363	$ 1,085,522	$ 1,084,582	$ 1,083,557	$ 1,082,503	$ 1,082,662	$ 1,081,895	$ 13,026,708

For Project: CAIR Crystal River AFUDC - FGD Common (Project 7.4d)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 6,729,489	$ (792,274)	$ 225,792	$ 386,512	$ 383,200	$ 468,505	$ 482,347	$ 267,610	$ 421,764	$ 225,380	$ 409,081	$ 65,154	$ 9,272,561
	b. Clearings to Plant			6,729,489	(792,274)	225,792	386,512	383,200	468,505	482,347	267,610	411,764	175,380	302,148	232,087	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		616,066,880	622,796,370	622,004,096	622,229,887	622,616,399	622,999,599	623,468,104	623,950,451	624,218,061	624,629,826	624,805,206	625,107,354	625,339,441	
3	Less: Accumulated Depreciation		(16,419,709)	(17,717,201)	(19,013,043)	(20,309,355)	(21,606,472)	(22,904,388)	(24,203,280)	(25,503,177)	(26,803,631)	(28,104,943)	(29,406,621)	(30,708,928)	(32,011,719)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	10,000	60,000	166,933	0	
5	Net Investment (Lines 2 + 3 + 4)		599,647,171	605,079,169	602,991,053	601,920,532	601,009,927	600,095,211	599,264,824	598,447,274	597,414,430	596,534,883	595,458,585	594,565,359	593,327,722	
6	Average Net Investment			602,363,170	604,035,111	602,455,793	601,465,230	600,552,569	599,680,018	598,856,049	597,930,852	596,974,657	595,996,734	595,011,972	593,946,541	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		4,027,509	4,038,688	4,028,129	4,021,505	4,015,403	4,009,569	4,004,060	3,997,874	3,991,481	3,984,942	3,978,358	3,971,234	48,068,752
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		1,482,002	1,486,115	1,482,229	1,479,792	1,477,647	1,475,400	1,473,373	1,471,097	1,468,744	1,466,338	1,463,915	1,461,294	17,687,646
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		1,297,492	1,295,842	1,296,312	1,297,117	1,297,916	1,298,892	1,299,897	1,300,454	1,301,312	1,301,678	1,302,307	1,302,791	15,592,010
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		410,527	410,004	410,153	410,408	410,661	410,989	411,287	411,464	411,735	411,851	412,050	412,203	4,933,312
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			7,217,530	7,230,649	7,216,823	7,208,822	7,201,527	7,194,830	7,188,617	7,180,889	7,173,272	7,164,809	7,156,630	7,147,522	86,281,020
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 7,217,530	$ 7,230,649	$ 7,216,823	$ 7,208,822	$ 7,201,527	$ 7,194,830	$ 7,188,617	$ 7,180,889	$ 7,173,272	$ 7,164,809	$ 7,156,630	$ 7,147,522	$ 86,281,020

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2011 through December 2011
CAIR Crystal River (Project 7.4 Recap)

For Project: CAIR Crystal River AFUDC - SCR Common Items (Project 7.4e)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 388	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 388
	b. Clearings to Plant			388	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		61,260,314	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	
3	Less: Accumulated Depreciation		(2,327,461)	(2,455,087)	(2,582,713)	(2,710,339)	(2,837,965)	(2,965,591)	(3,093,217)	(3,220,843)	(3,348,469)	(3,476,095)	(3,603,721)	(3,731,347)	(3,858,973)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		58,932,853	58,805,615	58,677,989	58,550,363	58,422,737	58,295,111	58,167,485	58,039,859	57,912,233	57,784,607	57,656,981	57,529,355	57,401,729	
6	Average Net Investment			58,869,234	58,741,802	58,614,176	58,486,550	58,358,924	58,231,298	58,103,672	57,976,046	57,848,420	57,720,794	57,593,168	57,465,542	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		393,610	392,758	391,905	391,052	390,198	389,345	388,492	387,638	386,785	385,932	385,078	384,225	4,667,018
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		144,837	144,523	144,209	143,895	143,581	143,267	142,953	142,639	142,325	142,011	141,697	141,383	1,717,320
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		127,626	127,626	127,626	127,626	127,626	127,626	127,626	127,626	127,626	127,626	127,626	127,626	1,531,512
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		40,381	40,381	40,381	40,381	40,381	40,381	40,381	40,381	40,381	40,381	40,381	40,381	484,572
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			706,454	705,288	704,121	702,954	701,786	700,619	699,452	698,284	697,117	695,950	694,782	693,615	8,400,422
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 706,454	$ 705,288	$ 704,121	$ 702,954	$ 701,786	$ 700,619	$ 699,452	$ 698,284	$ 697,117	$ 695,950	$ 694,782	$ 693,615	$ 8,400,422

For Project: CAIR Crystal River AFUDC - Flue Gas Desulfurization CR5 (Project 7.4f)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ (6,684,218)	$ 87	$ 18,857	$ 13,156	$ 34,941	$ 9,454	$ 12,382	$ 8,802	$ 9,900	$ 12,157	$ 97	$ 98	$ (6,564,286)
	b. Clearings to Plant			(6,684,218)	87	18,857	13,156	34,941	9,454	12,382	8,802	9,900	12,157	97	98	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		136,523,748	129,839,530	129,839,617	129,858,474	129,871,630	129,906,570	129,916,025	129,928,407	129,937,209	129,947,109	129,959,266	129,959,363	129,959,461	
3	Less: Accumulated Depreciation		(3,555,508)	(3,826,007)	(4,096,506)	(4,367,044)	(4,637,610)	(4,908,249)	(5,178,907)	(5,449,591)	(5,720,294)	(5,991,017)	(6,261,765)	(6,532,514)	(6,803,263)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		132,968,240	126,013,523	125,743,111	125,491,430	125,234,020	124,998,321	124,737,118	124,478,816	124,216,915	123,956,092	123,697,501	123,426,849	123,156,198	
6	Average Net Investment			129,490,881	125,878,317	125,617,271	125,362,725	125,116,171	124,867,720	124,607,967	124,347,866	124,086,503	123,826,796	123,562,175	123,291,523	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		865,799	841,645	839,900	838,198	836,549	834,888	833,151	831,412	829,665	827,928	826,159	824,349	10,029,643
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		318,588	309,700	309,058	308,431	307,825	307,214	306,575	305,935	305,292	304,653	304,002	303,336	3,690,609
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		270,499	270,499	270,538	270,566	270,639	270,658	270,684	270,703	270,723	270,748	270,749	270,749	3,247,755
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		85,586	85,586	85,598	85,607	85,630	85,636	85,644	85,650	85,657	85,665	85,665	85,665	1,027,589
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,540,472	1,507,430	1,505,094	1,502,802	1,500,643	1,498,396	1,496,054	1,493,700	1,491,337	1,488,994	1,486,575	1,484,099	17,995,596
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 1,540,472	$ 1,507,430	$ 1,505,094	$ 1,502,802	$ 1,500,643	$ 1,498,396	$ 1,496,054	$ 1,493,700	$ 1,491,337	$ 1,488,994	$ 1,486,575	$ 1,484,099	$ 17,995,596

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2011 through December 2011
CAIR Crystal River (Project 7.4 Recap)

For Project: CAIR Crystal River AFUDC - CR5 Sootblower & Intelligent Soot Blowing Controls(Project 7.4g)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1 Investments															
a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		850,198	850,198	850,198	850,198	850,198	850,198	850,198	850,198	850,198	850,198	850,198	850,198	850,198	
3 Less: Accumulated Depreciation		(13,643)	(15,414)	(17,185)	(18,956)	(20,727)	(22,498)	(24,269)	(26,040)	(27,811)	(29,582)	(31,353)	(33,124)	(34,895)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		836,555	834,784	833,013	831,242	829,471	827,700	825,929	824,158	822,387	820,616	818,845	817,074	815,303	
6 Average Net Investment			835,669	833,898	832,127	830,356	828,585	826,814	825,043	823,272	821,501	819,730	817,959	816,188	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		5,587	5,576	5,564	5,552	5,540	5,528	5,516	5,505	5,493	5,481	5,469	5,457	66,268
b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		2,056	2,052	2,047	2,043	2,039	2,034	2,030	2,026	2,021	2,017	2,012	2,008	24,385
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	2.50%		1,771	1,771	1,771	1,771	1,771	1,771	1,771	1,771	1,771	1,771	1,771	1,771	21,252
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.007910		560	560	560	560	560	560	560	560	560	560	560	560	6,720
e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			9,974	9,959	9,942	9,928	9,910	9,893	9,877	9,862	9,845	9,829	9,812	9,798	118,625
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 9,974	$ 9,959	$ 9,942	$ 9,928	$ 9,910	$ 9,893	$ 9,877	$ 9,862	$ 9,845	$ 9,829	$ 9,812	$ 9,798	$ 118,625

For Project: CAIR Crystal River AFUDC - CR4 Sootblower & Intelligent Soot Blowing Controls (Project 7.4h)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1 Investments															
a. Expenditures/Additions			$ 0	$ (593)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ (593)
b. Clearings to Plant			0	(593)	0	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		917,991	917,991	917,397	917,397	917,397	917,397	917,397	917,397	917,397	917,397	917,397	917,397	917,397	
3 Less: Accumulated Depreciation		(10,406)	(12,318)	(14,229)	(16,140)	(18,051)	(19,962)	(21,873)	(23,784)	(25,695)	(27,606)	(29,517)	(31,428)	(33,339)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		907,585	905,673	903,169	901,258	899,347	897,436	895,525	893,614	891,703	889,792	887,881	885,970	884,059	
6 Average Net Investment			906,629	904,421	902,213	900,302	898,391	896,480	894,569	892,658	890,747	888,836	886,925	885,014	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		6,062	6,047	6,032	6,020	6,007	5,994	5,981	5,968	5,956	5,943	5,930	5,917	71,857
b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		2,231	2,225	2,220	2,215	2,210	2,206	2,201	2,196	2,192	2,187	2,182	2,177	26,442
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	2.50%		1,912	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911	22,933
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.007910		605	605	605	605	605	605	605	605	605	605	605	605	7,260
e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			10,810	10,788	10,768	10,751	10,733	10,716	10,698	10,680	10,664	10,646	10,628	10,610	128,492
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 10,810	$ 10,788	$ 10,768	$ 10,751	$ 10,733	$ 10,716	$ 10,698	$ 10,680	$ 10,664	$ 10,646	$ 10,628	$ 10,610	$ 128,492

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2011 through December 2011
CAIR Crystal River (Project 7.4 Recap)

For Project: CAIR Crystal River AFUDC - CR4 SCR (Project 7.4l)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 226,769	$ (457,019)	$ (345,043)	$ 115,194	$ 170,379	$ 123,438	$ 112,449	$ 98,616	$ 80,436	$ 80,519	$ 230,315	$ 180,320	$ 616,373
	b. Clearings to Plant			226,769	(457,019)	(345,043)	115,194	170,379	123,438	112,449	98,616	80,436	80,519	230,315	320	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		109,467,569	109,694,338	109,237,319	108,892,276	109,007,470	109,177,849	109,301,288	109,413,736	109,512,351	109,592,787	109,673,306	109,903,622	109,903,942	
3	Less: Accumulated Depreciation		(1,639,649)	(1,868,179)	(2,095,757)	(2,322,616)	(2,549,715)	(2,777,169)	(3,004,880)	(3,232,825)	(3,460,976)	(3,689,294)	(3,917,780)	(4,146,746)	(4,375,713)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	180,000	
5	Net Investment (Lines 2 + 3 + 4)		107,827,920	107,826,159	107,141,562	106,569,660	106,457,755	106,400,680	106,296,408	106,180,911	106,051,375	105,903,493	105,755,526	105,756,876	105,708,229	
6	Average Net Investment			107,827,040	107,483,861	106,855,611	106,513,707	106,429,217	106,348,543	106,238,658	106,116,143	105,977,434	105,829,510	105,756,201	105,732,552	
7	Return on Average Net Investment															
	b. Equity Component Grossed Up For Taxes	8.02%		720,951	718,657	714,456	712,170	711,605	711,066	710,331	709,512	708,584	707,596	707,105	706,947	8,538,979
	a. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		265,288	264,444	262,898	262,057	261,849	261,651	261,380	261,079	260,738	260,374	260,193	260,135	3,142,088
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		228,530	227,578	226,859	227,069	227,454	227,711	227,945	228,151	228,318	228,486	228,666	228,987	2,736,064
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		72,307	72,006	71,778	71,854	71,966	72,048	72,122	72,187	72,240	72,293	72,445	72,445	865,891
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,287,076	1,282,685	1,275,991	1,273,180	1,272,874	1,272,476	1,271,778	1,270,929	1,269,880	1,268,748	1,268,709	1,268,494	15,282,820
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 1,287,076	$ 1,282,685	$ 1,275,991	$ 1,273,180	$ 1,272,874	$ 1,272,476	$ 1,271,778	$ 1,270,929	$ 1,269,880	$ 1,268,748	$ 1,268,709	$ 1,268,494	$ 15,282,820

For Project: CAIR Crystal River AFUDC - CR4 FGD (Project 7.4j)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 160,503	$ 9,655	$ (94,650)	$ (57,177)	$ (27,439)	$ 15,733	$ 20,357	$ 14,302	$ 15,813	$ 18,715	$ 133	$ 135	$ 76,082
	b. Clearings to Plant			160,503	9,655	(94,650)	(57,177)	(27,439)	15,733	20,367	14,302	15,813	18,715	133	135	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		140,054,642	140,215,145	140,224,800	140,130,150	140,072,974	140,045,535	140,061,268	140,081,624	140,095,927	140,111,739	140,130,455	140,130,588	140,130,723	
3	Less: Accumulated Depreciation		(2,102,806)	(2,304,921)	(2,687,056)	(2,978,994)	(3,270,813)	(3,562,575)	(3,854,380)	(4,146,206)	(4,438,073)	(4,729,972)	(5,021,910)	(5,313,849)	(5,605,788)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		137,951,836	137,820,224	137,537,744	137,151,156	136,802,161	136,482,960	136,206,888	135,935,418	135,657,854	135,381,767	135,108,545	134,816,739	134,524,935	
6	Average Net Investment			137,886,030	137,678,984	137,344,450	136,976,658	136,642,560	136,344,929	136,071,159	135,796,636	135,519,810	135,245,156	134,962,642	134,670,837	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		921,931	920,547	918,310	915,851	913,617	911,627	909,796	907,961	906,110	904,274	902,385	900,434	10,932,843
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		339,243	338,733	337,910	337,005	336,183	335,461	334,778	334,102	333,421	332,745	332,060	331,332	4,022,963
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		292,115	292,135	291,938	291,819	291,762	291,794	291,837	291,867	291,899	291,938	291,939	291,939	3,502,982
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		92,425	92,432	92,369	92,331	92,313	92,324	92,337	92,347	92,357	92,369	92,369	92,370	1,108,343
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,645,714	1,643,847	1,640,527	1,637,006	1,633,875	1,631,106	1,628,748	1,626,277	1,623,787	1,621,326	1,618,743	1,616,075	19,567,121
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 1,645,714	$ 1,643,847	$ 1,640,527	$ 1,637,006	$ 1,633,875	$ 1,631,106	$ 1,628,748	$ 1,626,277	$ 1,623,787	$ 1,621,326	$ 1,618,743	$ 1,616,075	$ 19,567,121

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2011 through December 2011
CAIR Crystal River (Project 7.4 Recap)

For Project: CAIR Crystal River AFUDC - Gypsum Handling (Project 7.4k)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ (205)	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ (205)
	b. Clearings to Plant			(205)	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		20,988,402	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	
3	Less: Accumulated Depreciation		(550,130)	(593,855)	(637,580)	(681,305)	(725,030)	(768,755)	(812,480)	(856,205)	(899,930)	(943,655)	(987,380)	(1,031,105)	(1,074,830)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		20,438,272	20,394,341	20,350,616	20,306,891	20,263,166	20,219,441	20,175,716	20,131,991	20,088,266	20,044,541	20,000,816	19,957,091	19,913,366	
6	Average Net Investment			20,416,307	20,372,479	20,328,754	20,285,029	20,241,304	20,197,579	20,153,854	20,110,129	20,066,404	20,022,679	19,978,954	19,935,229	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		136,507	136,214	135,922	135,629	135,337	135,045	134,752	134,460	134,168	133,875	133,583	133,291	1,618,783
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		50,230	50,123	50,015	49,908	49,800	49,692	49,585	49,477	49,370	49,262	49,154	49,047	595,663
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		43,725	43,725	43,725	43,725	43,725	43,725	43,725	43,725	43,725	43,725	43,725	43,725	524,700
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		13,835	13,835	13,835	13,835	13,835	13,835	13,835	13,835	13,835	13,835	13,835	13,835	166,020
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			244,297	243,897	243,497	243,097	242,697	242,297	241,897	241,497	241,098	240,697	240,297	239,898	2,905,166
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 244,297	$ 243,897	$ 243,497	$ 243,097	$ 242,697	$ 242,297	$ 241,897	$ 241,497	$ 241,098	$ 240,697	$ 240,297	$ 239,898	$ 2,905,166

For Project: CAIR Crystal River AFUDC - Acid Mist Mitigation Controls (Project 7.4l)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 1	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1
	b. Clearings to Plant			1	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		9,406,704	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	
3	Less: Accumulated Depreciation		(146,926)	(166,523)	(186,120)	(205,717)	(225,314)	(244,911)	(264,508)	(284,105)	(303,702)	(323,299)	(342,896)	(362,493)	(382,090)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		9,259,778	9,240,182	9,220,585	9,200,988	9,181,391	9,161,794	9,142,197	9,122,600	9,103,003	9,083,406	9,063,809	9,044,212	9,024,615	
6	Average Net Investment			9,249,980	9,230,384	9,210,787	9,191,190	9,171,593	9,151,996	9,132,399	9,112,802	9,093,205	9,073,608	9,054,011	9,034,414	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		61,847	61,716	61,585	61,454	61,323	61,192	61,061	60,930	60,799	60,668	60,537	60,406	733,518
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		22,758	22,710	22,661	22,613	22,565	22,517	22,469	22,420	22,372	22,324	22,276	22,227	269,912
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		19,597	19,597	19,597	19,597	19,597	19,597	19,597	19,597	19,597	19,597	19,597	19,597	235,164
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		6,201	6,201	6,201	6,201	6,201	6,201	6,201	6,201	6,201	6,201	6,201	6,201	74,412
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			110,403	110,224	110,044	109,865	109,686	109,507	109,328	109,148	108,969	108,790	108,611	108,431	1,313,006
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 110,403	$ 110,224	$ 110,044	$ 109,865	$ 109,686	$ 109,507	$ 109,328	$ 109,148	$ 108,969	$ 108,790	$ 108,611	$ 108,431	$ 1,313,006

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2011 through December 2011
CAIR Crystal River (Project 7.4 Recap)

For Project: CAIR Crystal River AFUDC - FGD Settling Pond (Project 7.4m)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1 Investments															
a. Expenditures/Additions			$ 52	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 52
b. Clearings to Plant			52	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		7,677,264	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	
3 Less: Accumulated Depreciation		(85,596)	(95,193)	(104,790)	(114,387)	(123,984)	(133,581)	(143,178)	(152,775)	(162,372)	(171,969)	(181,566)	(191,163)	(200,760)	
4 CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5 Net Investment (Lines 2 + 3 + 4)		7,591,668	7,582,123	7,572,526	7,562,929	7,553,332	7,543,735	7,534,138	7,524,541	7,514,944	7,505,347	7,495,750	7,486,153	7,476,556	
6 Average Net Investment			7,586,895	7,577,324	7,567,727	7,558,130	7,548,533	7,538,936	7,529,339	7,519,742	7,510,145	7,500,548	7,490,951	7,481,354	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		50,727	50,663	50,599	50,535	50,471	50,407	50,343	50,278	50,214	50,150	50,086	50,022	604,495
b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		18,666	18,643	18,619	18,596	18,572	18,548	18,525	18,501	18,477	18,454	18,430	18,406	222,436
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	1.50%		9,597	9,597	9,597	9,597	9,597	9,597	9,597	9,597	9,597	9,597	9,597	9,597	115,164
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.007910		5,061	5,061	5,061	5,061	5,061	5,061	5,061	5,061	5,061	5,061	5,061	5,061	60,732
e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			84,051	83,964	83,876	83,788	83,701	83,613	83,526	83,437	83,349	83,262	83,174	83,086	1,002,827
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 84,051	$ 83,964	$ 83,876	$ 83,788	$ 83,701	$ 83,613	$ 83,526	$ 83,437	$ 83,349	$ 83,262	$ 83,174	$ 83,086	$ 1,002,827

For Project: CAIR Crystal River AFUDC - Coal Pile Runoff Treatment System (Project 7.4n)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1 Investments															
a. Expenditures/Additions			$ 1	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1
b. Clearings to Plant			1	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		15,969,105	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	
3 Less: Accumulated Depreciation		(209,504)	(229,465)	(249,426)	(269,387)	(289,348)	(309,309)	(329,270)	(349,231)	(369,192)	(389,153)	(409,114)	(429,075)	(449,036)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		15,759,601	15,739,641	15,719,680	15,699,719	15,679,758	15,659,797	15,639,836	15,619,875	15,599,914	15,579,953	15,559,992	15,540,031	15,520,070	
6 Average Net Investment			15,749,621	15,729,661	15,709,700	15,689,739	15,669,778	15,649,817	15,629,856	15,609,895	15,589,934	15,569,973	15,550,012	15,530,051	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		105,305	105,171	105,038	104,904	104,771	104,638	104,504	104,371	104,237	104,104	103,970	103,837	1,254,850
b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		38,749	38,700	38,651	38,602	38,553	38,503	38,454	38,405	38,356	38,307	38,258	38,209	461,747
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	1.50%		19,961	19,961	19,961	19,961	19,961	19,961	19,961	19,961	19,961	19,961	19,961	19,961	239,532
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.007910		10,526	10,526	10,526	10,526	10,526	10,526	10,526	10,526	10,526	10,526	10,526	10,526	126,312
e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			174,541	174,358	174,176	173,993	173,811	173,628	173,445	173,263	173,080	172,898	172,715	172,533	2,082,441
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 174,541	$ 174,358	$ 174,176	$ 173,993	$ 173,811	$ 173,628	$ 173,445	$ 173,263	$ 173,080	$ 172,898	$ 172,715	$ 172,533	$ 2,082,441

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2011 through December 2011
CAIR Crystal River (Project 7.4 Recap)

For Project: CAIR Crystal River AFUDC - Dibasic Acid Additive System (Project 7.4o)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1 Investments															
a. Expenditures/Additions			$ 1	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1
b. Clearings to Plant			1	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		1,094,417	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	
3 Less: Accumulated Depreciation		(8,752)	(11,032)	(13,312)	(15,592)	(17,872)	(20,152)	(22,432)	(24,712)	(26,992)	(29,272)	(31,552)	(33,832)	(36,112)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		1,085,666	1,083,387	1,081,107	1,078,827	1,076,547	1,074,267	1,071,987	1,069,707	1,067,427	1,065,147	1,062,867	1,060,587	1,058,307	
6 Average Net Investment			1,084,526	1,082,247	1,079,967	1,077,687	1,075,407	1,073,127	1,070,847	1,068,567	1,066,287	1,064,007	1,061,727	1,059,447	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		7,251	7,236	7,221	7,206	7,190	7,175	7,160	7,145	7,129	7,114	7,099	7,084	86,010
b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		2,668	2,663	2,657	2,651	2,646	2,640	2,635	2,629	2,623	2,618	2,612	2,607	31,649
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	2.50%		2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	27,360
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.007910		721	721	721	721	721	721	721	721	721	721	721	721	8,652
e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			12,920	12,900	12,879	12,858	12,837	12,816	12,796	12,775	12,753	12,733	12,712	12,692	153,071
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 12,920	$ 12,900	$ 12,879	$ 12,858	$ 12,837	$ 12,816	$ 12,796	$ 12,775	$ 12,753	$ 12,733	$ 12,712	$ 12,692	$ 153,071

For Project: CAIR Crystal River AFUDC - Bottom Ash (PH)/Fly Ash (Ammonia) (Project 7.4p)
(in Dollars)

Line Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1 Investments															
a. Expenditures/Additions			$ (11,534)	$ 0	$ 0	$ 8,879	$ 12	$ 905	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,200,000	$ 1,198,263
b. Clearings to Plant			0	0	0	0	5,316	32,418	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		0	0	0	0	0	5,316	37,734	37,734	37,734	37,734	37,734	37,734	37,734	
3 Less: Accumulated Depreciation		0	0	0	0	0	(5)	(43)	(109)	(175)	(241)	(307)	(373)	(439)	
4 CWIP - Non-Interest Bearing		39,471	27,938	27,938	27,938	36,817	31,514	0	0	0	0	0	0	1,200,000	
5 Net Investment (Lines 2 + 3 + 4)		39,471	27,938	27,938	27,938	36,817	36,825	37,691	37,625	37,559	37,493	37,427	37,361	1,237,295	
6 Average Net Investment			33,705	27,938	27,938	32,378	36,821	37,258	37,658	37,592	37,526	37,460	37,394	637,328	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		225	187	187	216	246	249	252	251	251	250	250	4,261	6,825
b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		83	69	69	80	91	92	93	92	92	92	92	1,568	2,513
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	2.10%		0	0	0	0	5	38	66	66	66	66	66	66	439
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.007910		0	0	0	0	4	25	25	25	25	25	25	25	179
e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			308	256	256	296	346	404	436	434	434	433	433	5,920	9,958
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 308	$ 256	$ 256	$ 296	$ 346	$ 404	$ 436	$ 434	$ 434	$ 433	$ 433	$ 5,920	$ 9,958

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Programs Detail Support - January 2011 through December 2011
Crystal River Thermal Discharge Compliance (Project 11.1 Recap)

For Project: Crystal River Thermal Discharge Compliance Project AFUDC - Point of Discharge (POD) Cooling Tower (Project 11.1a)
(in Dollars)

Base

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		0	0	0	0	0	0	0	0	0	0	0	0	0	
6	Average Net Investment			0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009790		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0

For Project: Crystal River Thermal Discharge Compliance Project AFUDC - MET Tower (Project 11.1b)
(in Dollars)

Base

Line	Description		Beginning of Period Amount	Actual Jan-11	Actual Feb-11	Actual Mar-11	Actual Apr-11	Actual May-11	Actual Jun-11	Estimated Jul-11	Estimated Aug-11	Estimated Sep-11	Estimated Oct-11	Estimated Nov-11	Estimated Dec-11	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	
3	Less: Accumulated Depreciation		(8,578)	(9,090)	(9,602)	(10,114)	(10,626)	(11,138)	(11,650)	(12,162)	(12,674)	(13,186)	(13,698)	(14,210)	(14,722)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		353,158	352,646	352,134	351,622	351,110	350,598	350,086	349,574	349,062	348,550	348,038	347,526	347,014	
6	Average Net Investment			352,902	352,390	351,878	351,366	350,854	350,342	349,830	349,318	348,806	348,294	347,782	347,270	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		2,360	2,356	2,353	2,349	2,346	2,342	2,339	2,336	2,332	2,329	2,325	2,322	28,089
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		868	867	866	864	863	862	861	859	858	857	856	854	10,335
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.70%		512	512	512	512	512	512	512	512	512	512	512	512	6,144
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009790		295	295	295	295	295	295	295	295	295	295	295	295	3,540
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			4,035	4,030	4,026	4,020	4,016	4,011	4,007	4,002	3,997	3,993	3,988	3,983	48,108
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 4,035	$ 4,030	$ 4,026	$ 4,020	$ 4,016	$ 4,011	$ 4,007	$ 4,002	$ 3,997	$ 3,993	$ 3,988	$ 3,983	$ 48,108

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental cost recovery clause.	DOCKET NO. 110007-EI DATED: OCTOBER 14, 2011

PROGRESS ENERGY FLORIDA'S NOTICE OF FILING REVISIONS TO TESTIMONY AND EXHIBIT

PROGRESS ENERGY FLORIDA, INC., ("PEF"), hereby provides notice of filing revisions to the testimony of Thomas G. Foster and Exhibit No. __ (TGF-3) filed on August 26, 2011, as further described below:

1. The revisions reflect PEF's agreement with Staff to utilize a three year (rather than one year) amortization period for the proposed regulatory asset associated with PEF's remaining CAIR NOx allowances. Changing the amortization period results in a reduction of PEF's 2012 revenue requirements by $13,892,463.

2. PEF also has corrected two minor math errors that are described in PEF's response to Staff Interrogatory No.18b. The impact of correcting the math errors is to increase 2012 revenue requirements by $26,250.

3. The combined impact of the revisions described above is to reduce 2012 revenue requirements by $13,866,213 and to reduce PEF's proposed residential ECRC rates from $5.83/mWh to $5.45/mWh. These changes are reflected in Revised Forms 42-1P, 42-2P, 42-3P, 42-4P page 5 of 16, 42-5P page 5 of 18 and 42-7P of Exhibit No. _ (TGF-3), which are provided in Attachment "A" to this Notice. Corresponding revisions to Mr. Foster's testimony are specified in Attachment "B" to this Notice.

DATED this 14th day of October, 2011.

HOPPING GREEN & SAMS, P.A.

By:

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

Attorneys for Progress Energy Florida, Inc.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic-mail and regular U.S. mail this 14th day of October, 2011.

Martha Carter Brown
Office of General Counsel
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850
mbrown@psc.state.fl.us

John T. Butler, Esq.
Florida Power & Light Co.
700 Universe Blvd.
Juno Beach, FL 33408-0420
john.butler@fpl.com

Mr. Wade Litchfield
Florida Power & Light Co.
215 S. Monroe Street, Suite 810
Tallahassee, FL 32301
wade.litchfield@fpl.com

James D. Beasley, Esq.
Ausley & McMullen
P.O. Box 391
Tallahassee, FL 32302
jbeasley@ausley.com

John W. McWhirter, Jr.
McWhirter Reeves & Davidson, P.A.
P.O. Box 3350
Tampa, FL 33601-3350
jmcwhirter@mac-law.com

Jeffrey A. Stone, Esq.
Russell A. Badders, Esq.
Beggs & Lane Law Firm
P.O. Box 12950
Pensacola, FL 32591-2950
jas@beggslane.com
rab@beggslane.com

Susan Ritenour
Gulf Power Company
One Energy Place
Pensacola, FL 32520-0780
sdriteno@southernco.com

Capt. Shayla McNeill, USAF
Federal Executive Agencies
c/o AFLSA / JACL-ULT
139 Barnes Drive, Suite 1
Tyndall AFB, FL 32403
Shayla.mcneill@tyndall.af.mil

J.R. Kelly
Charles J. Rehwinkel
Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street, Rm. 812
Tallahassee, FL 32399
Kelly.jr@leg.state.fl.us
rehwinkel.charles@leg.state.fl.us

Paula K. Brown
Tampa Electric Company
Administrator, Regulatory Coordination
P.O. Box 111
Tampa, FL 33601-0111
Regdept@tecoenergy.com

R. Alexander Glenn
Deputy General Counsel - Florida
John T. Burnett
Associate General Counsel - Florida
Progress Energy Service Company, LLC
P.O. Box 14042
St. Petersburg, FL 33733
alex.glenn@pgnmail.com
john.burnett@pgnmail.com

Paul Lewis, Jr.
Progress Energy Florida, Inc.
106 East College Avenue, Suite 800\Tallahassee, FL 32301-7740
paul.lewisjr@pgnmail.com

Attorney

ATTACHMENT "A"

Revised Schedules to Exhibit No. __ (TGF-3)
originally filed on August 26, 2011

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to be Recovered
For the Projected Period
JANUARY 2012 - DECEMBER 2012
(in Dollars)

Revised Form 42-1P

Line		Energy ($)	Transmission Demand ($)	Distribution Demand ($)	Production Demand ($)	Total ($)
1	Total Jurisdictional Rev. Req. for the projected period					
	a Projected O&M Activities (Form 42-2P, Lines 7 through 9)	$ 38,872,301	$ 1,384,728	$ 2,426,549	$ 1,101,172	$ 43,784,750
	b Projected Capital Projects (Form 42-3P, Lines 7 through 9)	161,060,912	0	1,689	2,455,320	163,517,921
	c Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b)	199,933,213	1,384,728	2,428,238	3,556,492	207,302,671
2	True-up for Estimated Over/(Under) Recovery for the current period January 2011 - December 2011 (Form 42-2E, Line 5 + 6 + 10)	2,339,353	(2,105,287)	283,939	2,034,333	2,552,337
3	Final True-up for the period January 2010 - December 2010 (Form 42-1A, Line 3)	5,926,762	(331,768)	(100,916)	738,761	6,232,839
4	Total Jurisdictional Amount to Be Recovered/(Refunded) in the Projection period January 2012 - December 2012 (Line 1 - Line 2 - Line 3)	191,667,099	3,821,783	2,245,215	783,397	198,517,495
5	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier of 1.00072)	$ 191,805,099	$ 3,824,535	$ 2,246,832	$ 783,962	$ 198,660,428

Revised Form 42-2P

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2012 - DECEMBER 2012

O&M Activities
(in Dollars)

Line	Description	Projected Jan - 12	Projected Feb - 12	Projected Mar - 12	Projected Apr - 12	Projected May - 12	Projected Jun - 12	Projected Jul - 12	Projected Aug - 12	Projected Sep - 12	Projected Oct - 12	Projected Nov - 12	Projected Dec - 12	End of Period Total
1	Description of O&M Activities													
	1 Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$ 165,997	$ 165,997	$ 165,997	$ 165,997	$ 165,997	$ 165,997	$ 165,997	$ 165,997	$ 165,997	$ 165,997	$ 165,997	$ 165,997	$ 1,991,964
	1a Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	174,976	174,976	174,976	174,976	174,976	174,976	174,976	174,976	174,976	174,976	174,976	174,976	2,099,712
	2 Distribution System Environmental Investigation, Remediation, and Pollution Prevention	0	0	20,000	0	0	0	0	0	20,000	291,000	0	0	331,000
	3 Pipeline Integrity Management, Review/Update Plan and Risk Assessments - Intm	166,083	166,083	166,083	166,083	166,083	66,083	66,083	66,083	141,083	141,083	141,083	66,087	1,518,000
	4 Above Ground Tank Secondary Containment - Pkg	0	0	0	0	0	0	0	0	0	0	0	0	0
	5 SO2 & NOx Emissions Allowances - Energy	601,203	595,228	607,694	595,992	614,848	618,309	621,182	622,113	616,725	611,841	615,265	614,576	7,334,975
	6 Phase II Cooling Water Intake 316(b) - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
	6a Phase II Cooling Water Intake 316(b) - Intm	0	0	0	0	0	0	0	0	0	0	0	0	0
	7.2 CAIR - Peaking	19,500	25,000	5,000	0	0	5,000	0	0	5,000	0	21,600	9,600	90,700
	7.4 CAIR Crystal River - Base	862,800	957,376	1,366,520	1,074,554	1,045,445	974,883	920,402	1,257,179	1,010,441	966,388	1,537,144	1,426,492	13,399,625
	7.4 CAIR Crystal River - Energy	1,615,668	1,500,473	1,695,076	1,413,960	1,620,966	1,644,777	1,769,652	1,788,552	1,668,222	667,943	1,114,725	1,947,962	18,447,976
	7.4 CAIR Crystal River - A&G	14,336	15,896	20,804	24,119	23,675	23,427	28,714	23,902	18,547	18,547	18,547	23,359	253,875
	8 Arsenic Groundwater Standard - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
	9 Sea Turtle - Coastal Street Lighting - Distrib	416	416	416	416	416	416	416	416	416	416	416	416	4,992
	11 Modular Cooling Towers - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
	12 Greenhouse Gas Inventory and Reporting - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	13 Mercury Total Daily Maximum Loads Monitoring - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	14 Hazardous Air Pollutants (HAPs) ICR Program - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	15 Effluent Limitation Guidelines ICR Program - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	16 Nat. Pollutant Discharge Elimination Sys. (NPDES)-Energy	2,000	63,000	83,000	67,000	63,000	49,500	30,000	15,000	75,500	77,500	75,000	47,500	648,000
	17 Maximum Achievable Control Technology (MACT)-Energy	50,000	50,000	50,000	50,000	75,000	25,000	0	0	0	0	0	0	300,000
2	Total of O&M Activities	3,672,960	3,714,445	4,355,567	3,733,097	3,950,406	3,748,368	3,777,421	4,114,219	3,896,908	3,115,691	3,864,753	4,476,965	46,420,819
3	Recoverable Costs Allocated to Energy	2,268,872	2,208,700	2,435,770	2,126,952	2,373,814	2,337,586	2,420,833	2,425,665	2,360,447	1,357,284	1,804,989	2,610,038	26,730,951
4	Recoverable Costs Allocated to Demand - Transm	165,997	165,997	165,997	165,997	165,997	165,997	165,997	165,997	165,997	165,997	165,997	165,997	1,991,964
	Recoverable Costs Allocated to Demand - Distrib	175,392	175,392	195,392	175,392	175,392	175,392	175,392	175,392	195,392	466,392	175,392	175,392	2,435,704
	Recoverable Costs Allocated to Demand - Prod-Base	862,800	957,376	1,366,520	1,074,554	1,045,445	974,883	920,402	1,257,179	1,010,441	966,388	1,537,144	1,426,492	13,399,625
	Recoverable Costs Allocated to Demand - Prod-Intm	166,083	166,083	166,083	166,083	166,083	66,083	66,083	66,083	141,083	141,083	141,083	66,087	1,518,000
	Recoverable Costs Allocated to Demand - Prod-Peaking	19,500	25,000	5,000	0	0	5,000	0	0	5,000	0	21,600	9,600	90,700
	Recoverable Costs Allocated to Demand - A&G	14,336	15,896	20,804	24,119	23,675	23,427	28,714	23,902	18,547	18,547	18,547	23,359	253,875
5	Retail Energy Jurisdictional Factor	0.98770	0.97210	0.97650	0.97800	0.97820	0.97850	0.97700	0.97590	0.97460	0.97390	0.97450	0.97730	
6	Retail Transmission Demand Jurisdictional Factor	0.69516	0.69516	0.69516	0.69516	0.69516	0.69516	0.69516	0.69516	0.69516	0.69516	0.69516	0.69516	
	Retail Distribution Demand Jurisdictional Factor	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	
	Retail Production Demand Jurisdictional Factor - Base	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	
	Retail Production Demand Jurisdictional Factor - Intm	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	
	Retail Production Demand Jurisdictional Factor - Peaking	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	
	Retail Production Demand Jurisdictional Factor - A&G	0.92374	0.92374	0.92374	0.92374	0.92374	0.92374	0.92374	0.92374	0.92374	0.92374	0.92374	0.92374	
7	Jurisdictional Energy Recoverable Costs (A)	2,240,965	2,147,078	2,378,530	2,080,159	2,322,065	2,287,328	2,365,154	2,367,206	2,300,492	1,321,859	1,758,962	2,550,790	26,120,588
8	Jurisdictional Demand Recoverable Costs - Transm (B)	115,394	115,394	115,394	115,394	115,394	115,394	115,394	115,394	115,394	115,394	115,394	115,394	1,384,728
	Jurisdictional Demand Recoverable Costs - Distrib (B)	174,733	174,733	194,657	174,733	174,733	174,733	174,733	174,733	194,657	464,638	174,733	174,733	2,426,549
	Jurisdictional Demand Recoverable Costs - Prod-Base (B)	800,609	888,368	1,268,021	997,100	970,089	904,614	854,059	1,166,562	937,609	896,731	1,426,347	1,323,671	12,433,780
	Jurisdictional Demand Recoverable Costs - Prod-Intm (B)	120,478	120,478	120,478	120,478	120,478	47,937	47,937	47,937	102,343	102,343	102,343	47,940	1,101,170
	Jurisdictional Demand Recoverable Costs - Prod-Peaking (B)	17,935	22,993	4,599	0	0	4,599	0	0	4,599	0	19,866	8,829	83,420
	Jurisdictional Demand Recoverable Costs - A&G (B)	13,243	14,684	19,218	22,280	21,869	21,640	26,524	22,080	17,133	17,133	17,133	21,577	234,515
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 3,483,357	$ 3,483,728	$ 4,100,897	$ 3,510,144	$ 3,724,628	$ 3,556,245	$ 3,583,801	$ 3,893,912	$ 3,672,227	$ 2,918,098	$ 3,614,778	$ 4,242,934	$ 43,784,750

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

PROGRESS ENERGY FLORIDA

Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2012 - DECEMBER 2012
Capital Investment Projects-Recoverable Costs
(in Dollars)

Revised Form 42-3P

Line	Description	Projected Jan - 12	Projected Feb - 12	Projected Mar - 12	Projected Apr - 12	Projected May - 12	Projected Jun - 12	Projected Jul - 12	Projected Aug - 12	Projected Sep - 12	Projected Oct - 12	Projected Nov - 12	Projected Dec - 12	End of Period Total
1	Description of Investment Projects (A)													
3.1	Pipeline Integrity Management - Bartow/Anclote Pipeline-Intermediate	$ 38,028	$ 37,954	$ 37,879	$ 37,805	$ 37,731	$ 37,658	$ 37,583	$ 37,510	$ 37,436	$ 37,361	$ 37,285	$ 37,212	$ 451,442
4.1	Above Ground Tank Secondary Containment - Peaking	140,364	140,051	139,737	139,423	139,112	138,799	138,487	138,174	137,860	137,548	137,235	136,924	1,663,714
4.2	Above Ground Tank Secondary Containment - Base	32,345	32,292	32,236	32,180	32,125	32,070	32,015	31,959	31,903	31,849	31,794	31,738	384,506
4.3	Above Ground Tank Secondary Containment - Intermediate	3,058	3,054	3,049	3,045	3,039	3,034	3,030	3,024	3,020	3,015	3,010	3,005	36,383
5	SO2 & NOX Emissions Allowances - Energy	234,764	229,292	223,790	218,264	212,704	207,065	201,397	195,710	190,045	184,427	178,814	173,190	2,449,462
7.1	CAIR Anclote- Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0
7.2	CAIR CT's - Peaking	21,092	21,057	21,025	20,994	20,962	20,929	20,898	20,864	20,832	20,800	20,768	20,734	250,955
7.3	CAIR Crystal River - Base	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	31,728
7.4	CAIR Crystal River AFUDC - Base	14,241,599	14,225,042	14,201,549	14,191,474	14,213,641	14,250,578	14,249,116	14,225,446	14,201,781	14,193,357	14,203,902	14,246,224	170,643,709
7.4	CAIR Crystal River - Energy	5,408	5,408	5,408	5,408	5,408	5,408	5,406	5,408	5,408	5,408	5,408	5,408	64,897
9	Sea Turtle - Coastal Street Lighting -Distribution	142	142	142	142	142	141	141	141	141	141	141	139	1,695
10.1	Underground Storage Tanks-Base	1,757	1,755	1,752	1,749	1,746	1,744	1,741	1,738	1,735	1,733	1,730	1,727	20,907
10.2	Underground Storage Tanks-Intermediate	846	845	842	841	839	837	835	834	831	830	827	826	10,033
11	Modular Cooling Towers - Base	438	438	438	438	438	438	438	438	438	438	438	438	5,256
11.1	Crystal River Thermal Discharge Compliance Project AFUDC - Base	3,978	3,974	3,970	3,964	3,960	3,955	3,951	3,946	3,941	3,937	3,932	3,927	47,435
16	National Pollutant Discharge Elimination System (NPDES)-Intermediate	148	5,562	11,844	14,551	17,454	19,411	20,201	20,292	20,383	20,472	20,561	20,646	191,525
2	Total Investment Projects - Recoverable Costs	14,726,611	14,709,510	14,686,305	14,672,922	14,691,945	14,724,711	14,717,885	14,688,128	14,658,398	14,643,960	14,648,489	14,684,782	176,253,647
3	Recoverable Costs Allocated to Energy	240,172	234,700	229,198	223,672	218,112	212,473	206,805	201,118	195,453	189,835	184,222	178,598	2,514,359
4	Recoverable Costs Allocated to Demand - Distribution	142	142	142	142	142	141	141	141	141	141	141	139	1,695
	Recoverable Costs Allocated to Demand - Production - Base	14,282,761	14,266,145	14,242,589	14,232,449	14,254,554	14,291,429	14,289,905	14,266,171	14,242,442	14,233,958	14,244,440	14,286,698	171,133,541
	Recoverable Costs Allocated to Demand - Production - Intermediate	42,080	47,415	53,614	56,242	59,063	60,940	61,649	61,660	61,670	61,678	61,683	61,689	689,383
	Recoverable Costs Allocated to Demand - Production - Peaking	161,456	161,108	160,762	160,417	160,074	159,728	159,385	159,038	158,692	158,348	158,003	157,658	1,914,669
5	Retail Energy Jurisdictional Factor	0.98770	0.97210	0.97650	0.97800	0.97820	0.97850	0.97700	0.97590	0.97460	0.97390	0.97450	0.97730	
6	Retail Distribution Demand Jurisdictional Factor	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	
	Retail Demand Jurisdictional Factor - Production - Base	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	
	Retail Demand Jurisdictional Factor - Production - Intermediate	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	
	Retail Demand Jurisdictional Factor - Production - Peaking	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	
7	Jurisdictional Energy Recoverable Costs (B)	237,218	228,152	223,812	218,751	213,357	207,905	202,049	196,271	190,489	184,880	179,524	174,544	2,456,953
8	Jurisdictional Demand Recoverable Costs - Distribution (C)	141	141	141	141	141	140	140	140	140	140	140	138	1,689
	Jurisdictional Demand Recoverable Costs - Production - Base (C)	13,253,260	13,237,841	13,215,983	13,206,574	13,227,086	13,261,303	13,259,889	13,237,865	13,215,847	13,207,974	13,217,701	13,256,913	158,798,235
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	30,525	34,395	38,892	40,799	42,845	44,206	44,721	44,729	44,736	44,742	44,745	44,750	500,085
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	148,494	148,174	147,856	147,539	147,223	146,905	146,590	146,270	145,952	145,636	145,319	145,001	1,760,959
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 13,669,639	$ 13,648,704	$ 13,626,685	$ 13,613,804	$ 13,630,653	$ 13,660,460	$ 13,653,388	$ 13,625,276	$ 13,597,164	$ 13,583,373	$ 13,587,430	$ 13,621,346	$ 163,517,921

Notes:

(A) Each project's Total System Recoverable Expenses on Form 42-4P, Line 9; Line 5 for Project 5 - Allowances and Project 7.4 - Reagents.
(B) Line 3 x Line 5
(C) Line 4 x Line 6

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2012 - DECEMBER 2012
Schedule of Amortization and Return
Deferred Gain on Sales of Emissions Allowances (Project 5)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan - 12	Projected Feb - 12	Projected Mar - 12	Projected Apr - 12	Projected May - 12	Projected Jun - 12	Projected Jul - 12	Projected Aug - 12	Projected Sep - 12	Projected Oct - 12	Projected Nov - 12	Projected Dec - 12	End of Period Total
1	Working Capital Dr (Cr)															
	a. 1581001 SO_2 Emission Allowance Inventory		$ 4,972,187	$ 4,954,700	$ 4,943,189	$ 4,919,212	$ 4,905,326	$ 4,873,792	$ 4,838,797	$ 4,800,929	$ 4,762,130	$ 4,728,719	$ 4,700,192	$ 4,668,241	$ 4,636,979	$ 4,636,979
	b. 25401FL Auctioned SO_2 Allowance		(1,554,395)	(1,511,726)	(1,469,057)	(1,426,388)	(1,386,941)	(1,343,869)	(1,300,798)	(1,257,726)	(1,214,655)	(1,171,583)	(1,128,512)	(1,085,440)	(1,042,369)	(1,042,369)
	c. 1581002 NO_x Emission Allowance Inventory		0	0	0	0	0	0	0	0	0	0	0	0	0	0
	d. 1823403 NO_x Emission Allowance Regulatory Asset (A)		22,549,875	21,923,489	21,297,104	20,670,719	20,044,333	19,417,948	18,791,562	18,165,177	17,538,792	16,912,406	16,286,021	15,659,635	15,033,250	15,033,250
2	Total Working Capital		25,967,667	25,366,463	24,771,236	24,163,542	23,562,718	22,947,870	22,329,561	21,708,380	21,086,267	20,469,542	19,857,701	19,242,436	18,627,860	18,627,860
3	Average Net Investment			25,667,065	25,068,850	24,467,389	23,863,130	23,255,294	22,638,716	22,018,971	21,397,323	20,777,904	20,163,621	19,550,068	18,935,148	
4	Return on Average Net Working Capital Balance (B)															
	a. Equity Component Grossed Up For Taxes	8.02%		171,615	167,615	163,593	159,553	155,489	151,367	147,223	143,066	138,925	134,818	130,715	126,604	1,790,583
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		63,149	61,677	60,197	58,711	57,215	55,698	54,174	52,644	51,120	49,609	48,099	46,586	658,879
5	Total Return Component (C)			234,764	229,292	223,790	218,264	212,704	207,065	201,397	195,710	190,045	184,427	178,814	173,190	2,449,462
6	Expense Dr (Cr)															
	a. 5090001 SO_2 Allowance Expense			17,487	11,511	23,977	13,886	31,534	34,995	37,868	38,799	33,411	28,527	31,951	31,262	335,208
	b. 4074004 SO_2 Allowance Amortization Expense			(42,669)	(42,669)	(42,669)	(44,279)	(43,071)	(43,071)	(43,071)	(43,071)	(43,071)	(43,071)	(43,071)	(43,071)	(516,858)
	c. 5091003 NO_x Allowance Expense			626,385	626,385	626,385	626,385	626,385	626,385	626,385	626,385	626,385	626,385	626,385	626,385	7,516,625
7	Net Expense (D)			601,203	595,228	607,694	595,992	614,848	618,309	621,182	622,113	616,725	611,841	615,265	614,576	7,334,975
8	Total System Recoverable Expenses (Lines 5 + 7)			835,967	824,520	831,484	814,256	827,552	825,374	822,579	817,823	806,770	796,268	794,079	787,766	9,784,437
	a. Recoverable costs allocated to Energy			835,967	824,520	831,484	814,256	827,552	825,374	822,579	817,823	806,770	796,268	794,079	787,766	9,784,437
	b. Recoverable costs allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor			0.98770	0.97210	0.97650	0.97800	0.97820	0.97850	0.97700	0.97590	0.97460	0.97390	0.97450	0.97730	
10	Demand Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Retail Energy-Related Recoverable Costs (E)			825,685	801,516	811,944	796,343	809,511	807,628	803,659	798,113	786,278	775,486	773,830	769,884	9,559,876
12	Retail Demand-Related Recoverable Costs (F)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Total Jurisdictional Recoverable Costs (Lines 11 + 12)			$ 825,685	$ 801,516	$ 811,944	$ 796,343	$ 809,511	$ 807,628	$ 803,659	$ 798,113	$ 786,278	$ 775,486	$ 773,830	$ 769,884	$ 9,559,876

Notes:
(A) As further described in the testimony of witnesses West and Foster, PEF expects the Cross-State Air Polution Rule (CSAPR) to impact the value of NOx allowances not used in 2011. PEF is reflecting the CSAPR impact by moving this investment to a regulatory asset to be amortized into rates over a 3 year period and be fully recovered by year end 2014.
(B) Line 3 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(C) Line 5 is reported on Capital Schedule
(D) Line 7 is reported on O&M Schedule
(E) Line 8a x Line 9.
(F) Line 8b x Line 10.

Docket No. 110007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. __(TGF-3)
Page 8 of 40

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2012 - DECEMBER 2012
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: **SO_2 and NOx Emissions**
Project No. 5

Project Description:
In accordance with Title IV of the Clean Air Act, CFR 40 Part 73 and Part 76, and Florida Administrative Code Rule 62-214 and the Clean Air Interstate Rule, PEF manages SO_2 and NOx emissions allowance inventory for the purpose of offsetting sulfur dioxide and nitrogen oxides emissions in compliance with the Federal Acid Rain Program. On 7/6/11, the EPA issued the Cross-State Air Pollution Rule (CSAPR) which serves as a replacement rule to CAIR. CSAPR significantly alters SO2 and NOx allowance programs. Under CAIR, Florida is required to comply with annual SO2 and NOx emission requirements and seasonal requirements regulating NOx emissions during the ozone season. Under CSAPR, Florida is no longer included in the group of states required to comply with annual emissions requirements. It is only covered by the ozone season portions of the CSAPR rule. CSAPR replaces CAIR starting 1/1/12. The effective compliance date for Florida is 5/1/12 (beginning of the ozone season). Further discussion of CSAPR is included in the testimony of Patricia Q. West.

Project Accomplishments:

For purposes of compliance with an affected unit's sulfur dioxide (SO_2) and nitrogen oxides (NO_X emissions requirements under the Acid Rain Program, air quality compliance costs are administered by an authorized account representative who evaluates a variety of resources and options. Activities performed include purchases of SO_2 and NO_X emissions allowances as well as auctions and transfers of SO_2 emissions allowances. Under the new CSAPR rule , emission allowances previously issued to utility companies under the Acid Rain Program have no value as of 1/1/12. Any NO_X allowances issued under the Acid Rain Program not used by the end of 2011 are not expected to be useful for compliance with the CSAPR rule. As such, PEF has reflected movement of these capital investments from the NO_X allowance inventory to a regulatory asset to be recovered in rates in 2012. SO_2 allowances will still have value under the existing acid rain program requirements.

Project Fiscal Expenditures:
January 1, 2011 to December 31, 2011: Project expenditures are estimated to be approximately $0.3 million lower than originally projected. This variance is primarily driven by lower than anticipated NO_X allowance prices partially offset by higher than projected NO_X allowance usage.

Project Progress Summary:
PEF continually evaluates its compliance strategy to manage the most cost effective program and to mitigate higher gas prices which can impact the fuel mix as it relates to emissions as a result of residual oil.

Project Projections:
For the period January 2012 through December 2012 SO_2 expenditures are expected to be approximately $0.3 million. NO_X expenses under the new seasonal program cannot be projected at this time, however PEF is reflecting approximately $7.5 million in amortization of the 2011 estimated year end NO_X allowance balance due to the discontinuation of the existing program.

Revised Form 42-7P

PROGRESS ENERGY FLORIDA

Environmental Cost Recovery Clause (ECRC)

Calculation of Environmental Cost Recovery Clause Rate Factors by Rate Class

JANUARY 2012 - DECEMBER 2012

Rate Class		(1) mWh Sales at Source Energy Allocator (%)	(2) 12CP Transmission Demand Allocator (%)	(3) 12CP & 1/13th AD Demand Allocator (%)	(4) NCP Distribution Allocator (%)	(5) Energy-Related Costs ($)	(6) Transmission Demand Costs ($)	(7) Distribution Demand Costs ($)	(8) Production Demand Costs ($)	(9) Total Environmental Costs ($)	(10) Projected Effective Sales at Meter Level (mWh)	(11) Environmental Cost Recovery Factors (cents/kWh)
Residential												
RS-1, RST-1, RSL-1, RSL-2, RSS-1												
	Secondary	50.602%	62.710%	61.779%	63.663%	$97,056,294	$2,398,376	$1,430,396	$484,322	$101,369,389	18,600,869	**0.545**
General Service Non-Demand												
GS-1, GST-1												
	Secondary										1,209,225	**0.539**
	Primary										5,940	**0.534**
	Transmission										4,255	**0.528**
	TOTAL GS	3.317%	2.922%	2.952%	3.549%	$6,361,459	$111,736	$79,740	$23,142	$6,576,077	**1,219,420**	
General Service												
GS-2	Secondary	0.327%	0.200%	0.210%	0.149%	$627,325	$7,658	$3,338	$1,646	$639,967	120,227	**0.532**
General Service Demand												
GSD-1, GSDT-1, SS-1												
	Secondary										12,082,271	**0.534**
	Primary										2,280,315	**0.529**
	Transmission										9,192	**0.523**
	TOTAL GSD	38.948%	30.363%	31.023%	28.881%	$74,703,564	$1,161,228	$648,898	$243,208	$76,756,898	**14,371,778**	
Curtailable												
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3												
	Secondary										-	**0.528**
	Primary										159,935	**0.523**
	Transmission										-	**0.517**
	TOTAL CS	0.425%	0.309%	0.318%	0.716%	$814,532	$11,813	$16,083	$2,491	$844,919	**159,935**	
Interruptible												
IS-1, IST-1, IS-2, IST-2, SS-2												
	Secondary										109,609	**0.520**
	Primary										1,501,477	**0.515**
	Transmission										422,008	**0.510**
	TOTAL IS	5.405%	3.380%	3.536%	2.117%	$10,367,851	$129,283	$47,561	$27,722	$10,572,417	**2,033,093**	
Lighting												
LS-1	Secondary	0.977%	0.116%	0.182%	0.926%	$1,874,075	$4,441	$20,816	$1,430	$1,900,761	359,167	**0.529**
		100.000%	100.000%	100.000%	100.000%	$191,805,099	$3,824,535	$2,246,832	$783,962	$198,660,428	36,864,489	**0.539**

Notes:

(1)	From Form 42-6P, Column 9
(2)	From Form 42-6P, Column 10
(3)	From Form 42-6P, Column 11
(4)	From Form 42-6P, Column 12
(5)	Column 1 x Total Energy Jurisdictional Dollars from Form 42-1P, line 5
(6)	Column 2 x Total Transmission Demand Jurisdictional Dollars from Form 42-1P, line 5
(7)	Column 4 x Total Distribution Demand Jurisdictional Dollars from Form 42-1P, line 5
(8)	Column 3 x Total Production Demand Jurisdictional Dollars from Form 42-1P, line 5
(9)	Column 5 + Column 6 + Column 7 + Column 8
(10)	Projected kWh sales at secondary voltage level for the period January 2012 to December 2012
(11)	(Column 9/ Column 10)/10

Attachment B

REVIESIONS TO TESTIMONY OF THOMAS G. FOSTER ORIGINALLY FILED ON AUGUST 26, 2011		
PAGE/LINE	**REIVISION**	**REASON FOR CHANGE**
1/2	Add "REVISED" before "DIRECT"	Denote this is revised testimony.
1/7	Strike "August 26" and replace with "October 14"	Update date filed.
3/8	Strike "212.5" replace with "198.7"	Change revenue requirements consistent with 3 year amortization of Nox allowance balance and errata corrections.
7/11	Strike "2012" replace with "three years from 2012-2014" and strike "The" replace with "One third of the"	Change language to be consistent with 3 year amortization of Nox allowance balance.
7/12	Strike "until"	Change language to be consistent with 3 year amortization of Nox allowance balance.
7/12	Strike "completely recovered at year end."	Change language to be consistent with 3 year amortization of Nox allowance balance.
7/18	After the word "balance," add "based on allowance usage, one third of"	Change language to be consistent with 3 year amortization of Nox allowance balance.
7/19	After the word "amortized" add "in 2012"	Change language to be consistent with 3 year amortization of Nox allowance balance.
8/3	Strike "58.5" and replace with "43.8"	Change revenue requirements consistent with 3 year amortization of Nox allowance balance and errata corrections.
8/9	Strike "162.7" and replace with "163.5"	Change revenue requirements consistent with 3 year amortization of Nox allowance balance and errata corrections.
8/19	Strike "221.2" replace with "207.3"	Change revenue requirements consistent with 3 year amortization of Nox allowance balance and errata corrections.
10	ECRC Factors Column	Change ECRC factors based on updated revenue requirements in the following table.
11/9	Strike "0.577" replace with "0.539"	Change ECRC factor based on updated revenue requirements.
11/10	Strike "221.2" replace with "207.3"	Change revenue requirements consistent with 3 year amortization of Nox allowance balance and errata corrections.

ATTACHMENT B
(Continued)

RATE CLASS	ECRC FACTORS 12CP & 1/13AD
Residential	0.545 cents/kWh
General Service Non-Demand	
@ Secondary Voltage	0.539 cents/kWh
@ Primary Voltage	0.534 cents/kWh
@ Transmission Voltage	0.528 cents/kWh
General Service 100% Load Factor	0.532 cents/kWh
General Service Demand	
@ Secondary Voltage	0.534 cents/kWh
@ Primary Voltage	0.529 cents/kWh
@ Transmission Voltage	0.523 cents/kWh
Curtailable	
@ Secondary Voltage	0.528 cents/kWh
@ Primary Voltage	0.523 cents/kWh
@ Transmission Voltage	0.517 cents/kWh
Interruptible	
@ Secondary Voltage	0.520 cents/kWh
@ Primary Voltage	0.515 cents/kWh
@ Transmission Voltage	0.510 cents/kWh
Lighting	0.529 cents/kWh

Witness: T.G. Foster
Exhibit__(TGF-4)

PROGRESS ENERGY FLORIDA, INC.
ENVIRONMENTAL COST RECOVERY
CAPITAL PROGRAM DETAIL

JANUARY 2012 - DECEMBER 2012
Calculation of the Projected Period Amount
January through December 2012
DOCKET NO. 110007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI EXHIBIT 29
PARTY PROGRESS ENERGY FLORIDA
DESCRIPTION THOMAS G. FOSTER (TGF-4)
DATE 11/01/11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 3.1 Recap
JANUARY 2012 - DECEMBER 2012

For Project: PIPELINE INTEGRITY MANAGEMENT - Alderman Road Fence (Project 3.1a)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	33,952	
3	Less: Accumulated Depreciation		(6,793)	(6,847)	(6,901)	(6,955)	(7,009)	(7,063)	(7,117)	(7,171)	(7,225)	(7,279)	(7,333)	(7,387)	(7,441)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		27,160	27,106	27,052	26,998	26,944	26,890	26,836	26,782	26,728	26,674	26,620	26,566	26,512	
6	Average Net Investment			27,133	27,079	27,025	26,971	26,917	26,863	26,809	26,755	26,701	26,647	26,593	26,539	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		181	181	181	180	180	180	179	179	179	178	178	177	$2,153
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		67	67	66	66	66	66	66	66	66	66	65	65	792
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation 1.90%			54	54	54	54	54	54	54	54	54	54	54	54	648
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.009219			26	26	26	26	26	26	26	26	26	26	26	26	312
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			328	328	327	326	326	326	325	325	325	324	323	322	3,905
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 328	$ 328	$ 327	$ 326	$ 326	$ 326	$ 325	$ 325	$ 325	$ 324	$ 323	$ 322	$ 3,905

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Leak Detection (Project 3.1b)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	2,640,636	
3	Less: Accumulated Depreciation		(658,979)	(664,700)	(670,421)	(676,142)	(681,863)	(687,584)	(693,305)	(699,026)	(704,747)	(710,468)	(716,189)	(721,910)	(727,631)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		1,981,657	1,975,936	1,970,215	1,964,494	1,958,773	1,953,052	1,947,331	1,941,610	1,935,889	1,930,168	1,924,447	1,918,726	1,913,005	
6	Average Net Investment			1,978,797	1,973,076	1,967,355	1,961,634	1,955,913	1,950,192	1,944,471	1,938,750	1,933,029	1,927,308	1,921,587	1,915,866	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		13,231	13,192	13,154	13,116	13,078	13,039	13,001	12,963	12,925	12,886	12,848	12,810	$156,243
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		4,868	4,854	4,840	4,826	4,812	4,798	4,784	4,770	4,756	4,742	4,728	4,714	57,492
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation 2.60%			5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	5,721	68,652
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.009219			2,029	2,029	2,029	2,029	2,029	2,029	2,029	2,029	2,029	2,029	2,029	2,029	24,348
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			25,849	25,796	25,744	25,692	25,640	25,587	25,535	25,483	25,431	25,378	25,326	25,274	306,735
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 25,849	$ 25,796	$ 25,744	$ 25,692	$ 25,640	$ 25,587	$ 25,535	$ 25,483	$ 25,431	$ 25,378	$ 25,326	$ 25,274	$ 306,735

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 3.1 Recap
JANUARY 2012 - DECEMBER 2012

For Project: PIPELINE INTEGRITY MANAGEMENT - Pipeline Controls Upgrade (Project 3.1c)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		909,407	909,407	909,407	909,407	909,407	909,407	909,407	909,407	909,407	909,407	909,407	909,407	909,407	
3	Less: Accumulated Depreciation		(85,372)	(87,342)	(89,312)	(91,282)	(93,252)	(95,222)	(97,192)	(99,162)	(101,132)	(103,102)	(105,072)	(107,042)	(109,012)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		824,035	822,065	820,095	818,125	816,155	814,185	812,215	810,245	808,275	806,305	804,335	802,365	800,395	
6	Average Net Investment			823,050	821,080	819,110	817,140	815,170	813,200	811,230	809,260	807,290	805,320	803,350	801,380	
7	*Return on Average Net Investment*															
	a. Equity Component Grossed Up For Taxes	8.02%		5,503	5,490	5,477	5,464	5,450	5,437	5,424	5,411	5,398	5,385	5,371	5,358	$65,168
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		2,025	2,020	2,015	2,010	2,006	2,001	1,996	1,991	1,986	1,981	1,976	1,972	23,979
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.60%		1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	1,970	23,640
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. *Property Taxes*	*0.009219*		699	699	699	699	699	699	699	699	699	699	699	699	8,388
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			10,197	10,179	10,161	10,143	10,125	10,107	10,089	10,071	10,053	10,035	10,016	9,999	121,175
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 10,197	$ 10,179	$ 10,161	$ 10,143	$ 10,125	$ 10,107	$ 10,089	$ 10,071	$ 10,053	$ 10,035	$ 10,016	$ 9,999	$ 121,175

For Project: PIPELINE INTEGRITY MANAGEMENT - Control Room Management (Project 3.1d)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		130,040	130,040	130,040	130,040	130,040	130,040	130,040	130,040	130,040	130,040	130,040	130,040	130,040	
3	Less: Accumulated Depreciation		(184)	(552)	(920)	(1,288)	(1,656)	(2,024)	(2,392)	(2,760)	(3,128)	(3,496)	(3,864)	(4,232)	(4,600)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		129,856	129,488	129,120	128,752	128,384	128,016	127,648	127,280	126,912	126,544	126,176	125,808	125,440	
6	*Average Net Investment*			129,672	129,304	128,936	128,568	128,200	127,832	127,464	127,096	126,728	126,360	125,992	125,624	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		867	865	862	860	857	855	852	850	847	845	842	840	$10,242
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		319	318	317	316	315	315	314	313	312	311	310	309	3,769
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.40%		368	368	368	368	368	368	368	368	368	368	368	368	4,416
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009219		100	100	100	100	100	100	100	100	100	100	100	100	1,200
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,654	1,651	1,647	1,644	1,640	1,638	1,634	1,631	1,627	1,624	1,620	1,617	19,627
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 1,654	$ 1,651	$ 1,647	$ 1,644	$ 1,640	$ 1,638	$ 1,634	$ 1,631	$ 1,627	$ 1,624	$ 1,620	$ 1,617	$ 19,627

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
JANUARY 2012 - DECEMBER 2012

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - TURNER CTs (Project 4.1a)
(in Dollars)

Line	Description	Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments														
	a. Expenditures/Additions		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	2,066,599	
3	Less: Accumulated Depreciation	(158,079)	(163,202)	(168,325)	(173,448)	(178,571)	(183,694)	(188,817)	(193,940)	(199,063)	(204,186)	(209,309)	(214,432)	(219,555)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	1,908,520	1,903,397	1,898,274	1,893,151	1,888,028	1,882,905	1,877,782	1,872,659	1,867,536	1,862,413	1,857,290	1,852,167	1,847,044	
6	Average Net Investment		1,905,959	1,900,836	1,895,713	1,890,590	1,885,467	1,880,344	1,875,221	1,870,098	1,864,975	1,859,852	1,854,729	1,849,606	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 8.02%		12,744	12,709	12,675	12,641	12,607	12,572	12,538	12,504	12,470	12,435	12,401	12,367	150,663
	b. Debt Component (Line 6 x Rate x 1/12) 2.95%		4,689	4,677	4,664	4,651	4,639	4,626	4,614	4,601	4,588	4,576	4,563	4,551	55,439
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation 2.98%		5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	5,123	61,476
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.010850		1,869	1,869	1,869	1,869	1,869	1,869	1,869	1,869	1,869	1,869	1,869	1,869	22,428
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		24,425	24,378	24,331	24,284	24,238	24,190	24,144	24,097	24,050	24,003	23,956	23,910	290,006
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		$ 24,425	$ 24,378	$ 24,331	$ 24,284	$ 24,238	$ 24,190	$ 24,144	$ 24,097	$ 24,050	$ 24,003	$ 23,956	$ 23,910	$ 290,006

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BARTOW CTs (Project 4.1b)
(in Dollars)

Line	Description	Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments														
	a. Expenditures/Additions		$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	1,473,801	
3	Less: Accumulated Depreciation	(115,671)	(119,356)	(123,041)	(126,726)	(130,411)	(134,096)	(137,781)	(141,466)	(145,151)	(148,836)	(152,521)	(156,206)	(159,891)	
4	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	1,358,130	1,354,445	1,350,760	1,347,075	1,343,390	1,339,705	1,336,020	1,332,335	1,328,650	1,324,965	1,321,280	1,317,595	1,313,910	
6	Average Net Investment		1,356,288	1,352,603	1,348,918	1,345,233	1,341,548	1,337,863	1,334,178	1,330,493	1,326,808	1,323,123	1,319,438	1,315,753	
7	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes 8.02%		9,068	9,044	9,019	8,994	8,970	8,945	8,921	8,896	8,871	8,847	8,822	8,797	107,194
	b. Debt Component (Line 6 x Rate x 1/12) 2.95%		3,337	3,328	3,319	3,310	3,301	3,292	3,282	3,273	3,264	3,255	3,246	3,237	39,444
	c. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a. Depreciation 3.00%		3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	3,685	44,220
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.009370		1,151	1,151	1,151	1,151	1,151	1,151	1,151	1,151	1,151	1,151	1,151	1,151	13,812
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		17,241	17,208	17,174	17,140	17,107	17,073	17,039	17,005	16,971	16,938	16,904	16,870	204,670
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		$ 17,241	$ 17,208	$ 17,174	$ 17,140	$ 17,107	$ 17,073	$ 17,039	$ 17,005	$ 16,971	$ 16,938	$ 16,904	$ 16,870	$ 204,670

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
JANUARY 2012 - DECEMBER 2012

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - CRYSTAL RIVER 1 & 2 (Project 4.2)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	33,092	
3	Less: Accumulated Depreciation		(10,995)	(11,097)	(11,199)	(11,301)	(11,403)	(11,505)	(11,607)	(11,709)	(11,811)	(11,913)	(12,015)	(12,117)	(12,219)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		22,097	21,995	21,893	21,791	21,689	21,587	21,485	21,383	21,281	21,179	21,077	20,975	20,873	
6	Average Net Investment			22,046	21,944	21,842	21,740	21,638	21,536	21,434	21,332	21,230	21,128	21,026	20,924	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		147	147	146	145	145	144	143	143	142	141	141	140	1,724
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		54	54	54	53	53	53	53	52	52	52	52	51	633
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.70%		102	102	102	102	102	102	102	102	102	102	102	102	1,224
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		22	22	22	22	22	22	22	22	22	22	22	22	264
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			325	325	324	322	322	321	320	319	318	317	317	315	3,845
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 325	$ 325	$ 324	$ 322	$ 322	$ 321	$ 320	$ 319	$ 318	$ 317	$ 317	$ 315	$ 3,845

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - INTERCESSION CITY CTs (Project 4.1c)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	1,661,664	
3	Less: Accumulated Depreciation		(395,459)	(404,598)	(413,737)	(422,876)	(432,015)	(441,154)	(450,293)	(459,432)	(468,571)	(477,710)	(486,849)	(495,988)	(505,127)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		1,266,205	1,257,066	1,247,927	1,238,788	1,229,649	1,220,510	1,211,371	1,202,232	1,193,093	1,183,954	1,174,815	1,165,676	1,156,537	
6	Average Net Investment			1,261,636	1,252,497	1,243,358	1,234,219	1,225,080	1,215,941	1,206,802	1,197,663	1,188,524	1,179,385	1,170,246	1,161,107	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		8,436	8,374	8,313	8,252	8,191	8,130	8,069	8,008	7,947	7,886	7,824	7,763	97,193
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		3,104	3,082	3,059	3,037	3,014	2,992	2,969	2,947	2,924	2,902	2,879	2,857	35,766
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	6.60%		9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	9,139	109,668
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008880		1,230	1,230	1,230	1,230	1,230	1,230	1,230	1,230	1,230	1,230	1,230	1,230	14,760
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			21,909	21,825	21,741	21,658	21,574	21,491	21,407	21,324	21,240	21,157	21,072	20,989	257,387
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 21,909	$ 21,825	$ 21,741	$ 21,658	$ 21,574	$ 21,491	$ 21,407	$ 21,324	$ 21,240	$ 21,157	$ 21,072	$ 20,989	$ 257,387

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
JANUARY 2012 - DECEMBER 2012

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - AVON PARK CTs (Project 4.1d)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	178,938	
3	Less: Accumulated Depreciation		(38,345)	(39,061)	(39,777)	(40,493)	(41,209)	(41,925)	(42,641)	(43,357)	(44,073)	(44,789)	(45,505)	(46,221)	(46,937)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		140,593	139,877	139,161	138,445	137,729	137,013	136,297	135,581	134,865	134,149	133,433	132,717	132,001	
6	Average Net Investment			140,235	139,519	138,803	138,087	137,371	136,655	135,939	135,223	134,507	133,791	133,075	132,359	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		938	933	928	923	918	914	909	904	899	895	890	885	10,936
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		345	343	341	340	338	336	334	333	331	329	327	326	4,023
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	4.80%		716	716	716	716	716	716	716	716	716	716	716	716	8,592
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008940		133	133	133	133	133	133	133	133	133	133	133	133	1,596
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			2,132	2,125	2,118	2,112	2,105	2,099	2,092	2,086	2,079	2,073	2,066	2,060	25,147
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 2,132	$ 2,125	$ 2,118	$ 2,112	$ 2,105	$ 2,099	$ 2,092	$ 2,086	$ 2,079	$ 2,073	$ 2,066	$ 2,060	$ 25,147

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - BAYBORO CTs (Project 4.1e)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	730,295	
3	Less: Accumulated Depreciation		(89,420)	(91,246)	(93,072)	(94,898)	(96,724)	(98,550)	(100,376)	(102,202)	(104,028)	(105,854)	(107,680)	(109,506)	(111,332)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		640,875	639,050	637,224	635,398	633,572	631,746	629,920	628,094	626,268	624,442	622,616	620,790	618,964	
6	Average Net Investment			639,963	638,137	636,311	634,485	632,659	630,833	629,007	627,181	625,355	623,529	621,703	619,877	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		4,279	4,267	4,254	4,242	4,230	4,218	4,206	4,193	4,181	4,169	4,157	4,145	50,541
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		1,575	1,570	1,566	1,561	1,557	1,552	1,548	1,543	1,539	1,534	1,530	1,525	18,600
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.00%		1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	1,826	21,912
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009370		570	570	570	570	570	570	570	570	570	570	570	570	6,840
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			8,250	8,233	8,216	8,199	8,183	8,166	8,150	8,132	8,116	8,099	8,083	8,066	97,893
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 8,250	$ 8,233	$ 8,216	$ 8,199	$ 8,183	$ 8,166	$ 8,150	$ 8,132	$ 8,116	$ 8,099	$ 8,083	$ 8,066	$ 97,893

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
JANUARY 2012 - DECEMBER 2012

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - SUWANNEE CTs (Project 4.1f)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	1,037,199	
3	Less: Accumulated Depreciation		(152,808)	(155,660)	(158,512)	(161,364)	(164,216)	(167,068)	(169,920)	(172,772)	(175,624)	(178,476)	(181,328)	(184,180)	(187,032)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		884,391	881,539	878,687	875,835	872,983	870,131	867,279	864,427	861,575	858,723	855,871	853,019	850,167	
6	Average Net Investment			882,965	880,113	877,261	874,409	871,557	868,705	865,853	863,001	860,149	857,297	854,445	851,593	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		5,904	5,885	5,866	5,846	5,827	5,808	5,789	5,770	5,751	5,732	5,713	5,694	69,585
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		2,172	2,165	2,158	2,151	2,144	2,137	2,130	2,123	2,116	2,109	2,102	2,095	25,602
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	3.30%		2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	2,852	34,224
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007670		663	663	663	663	663	663	663	663	663	663	663	663	7,956
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			11,591	11,565	11,539	11,512	11,486	11,460	11,434	11,408	11,382	11,356	11,330	11,304	137,367
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 11,591	$ 11,565	$ 11,539	$ 11,512	$ 11,486	$ 11,460	$ 11,434	$ 11,408	$ 11,382	$ 11,356	$ 11,330	$ 11,304	$ 137,367

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - DeBARY CTs (Project 4.1g)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		4,081,399	4,081,399	4,081,399	4,081,399	4,081,399	4,081,399	4,081,399	4,081,399	4,081,399	4,081,399	4,081,399	4,081,399	4,081,399	
3	Less: Accumulated Depreciation		(164,361)	(173,204)	(182,047)	(190,890)	(199,733)	(208,576)	(217,419)	(226,262)	(235,105)	(243,948)	(252,791)	(261,634)	(270,477)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		3,917,038	3,908,195	3,899,352	3,890,509	3,881,666	3,872,823	3,863,980	3,855,137	3,846,294	3,837,451	3,828,608	3,819,765	3,810,922	
6	Average Net Investment			3,912,617	3,903,774	3,894,931	3,886,088	3,877,245	3,868,402	3,859,559	3,850,716	3,841,873	3,833,030	3,824,187	3,815,344	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		26,160	26,101	26,042	25,983	25,924	25,865	25,806	25,747	25,687	25,628	25,569	25,510	310,022
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		9,626	9,605	9,583	9,561	9,539	9,517	9,496	9,474	9,452	9,430	9,409	9,387	114,079
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.60%		8,843	8,843	8,843	8,843	8,843	8,843	8,843	8,843	8,843	8,843	8,843	8,843	106,116
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.010850		3,690	3,690	3,690	3,690	3,690	3,690	3,690	3,690	3,690	3,690	3,690	3,690	44,280
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			48,319	48,239	48,158	48,077	47,996	47,915	47,835	47,754	47,672	47,591	47,511	47,430	574,497
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 48,319	$ 48,239	$ 48,158	$ 48,077	$ 47,996	$ 47,915	$ 47,835	$ 47,754	$ 47,672	$ 47,591	$ 47,511	$ 47,430	$ 574,497

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
JANUARY 2012 - DECEMBER 2012

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - University of Florida (Project 4.1h)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	141,435	
3	Less: Accumulated Depreciation		(42,990)	(43,226)	(43,462)	(43,698)	(43,934)	(44,170)	(44,406)	(44,642)	(44,878)	(45,114)	(45,350)	(45,586)	(45,822)	
4	CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5	Net Investment (Lines 2 + 3 + 4)		98,444	98,208	97,972	97,736	97,500	97,264	97,028	96,792	96,556	96,320	96,084	95,848	95,612	
6	Average Net Investment			98,326	98,090	97,854	97,618	97,382	97,146	96,910	96,674	96,438	96,202	95,966	95,730	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		657	656	654	653	651	650	648	646	645	643	642	640	7,785
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		242	241	241	240	240	239	238	238	237	237	236	236	2,865
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation 2.00%			236	236	236	236	236	236	236	236	236	236	236	236	2,832
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.014400			170	170	170	170	170	170	170	170	170	170	170	170	2,040
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,305	1,303	1,301	1,299	1,297	1,295	1,292	1,290	1,288	1,286	1,284	1,282	15,522
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 1,305	$ 1,303	$ 1,301	$ 1,299	$ 1,297	$ 1,295	$ 1,292	$ 1,290	$ 1,288	$ 1,286	$ 1,284	$ 1,282	$ 15,522

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Anclote (Project 4.3)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	290,297	
3	Less: Accumulated Depreciation		(34,986)	(35,518)	(36,050)	(36,582)	(37,114)	(37,646)	(38,178)	(38,710)	(39,242)	(39,774)	(40,306)	(40,838)	(41,370)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		255,312	254,780	254,248	253,716	253,184	252,652	252,120	251,588	251,056	250,524	249,992	249,460	248,928	
6	Average Net Investment			255,046	254,514	253,982	253,450	252,918	252,386	251,854	251,322	250,790	250,258	249,726	249,194	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		1,705	1,702	1,698	1,695	1,691	1,687	1,684	1,680	1,677	1,673	1,670	1,666	20,228
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		627	626	625	624	622	621	620	618	617	616	614	613	7,443
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation 2.20%			532	532	532	532	532	532	532	532	532	532	532	532	6,384
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes 0.008000			194	194	194	194	194	194	194	194	194	194	194	194	2,328
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			3,058	3,054	3,049	3,045	3,039	3,034	3,030	3,024	3,020	3,015	3,010	3,005	36,383
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 3,058	$ 3,054	$ 3,049	$ 3,045	$ 3,039	$ 3,034	$ 3,030	$ 3,024	$ 3,020	$ 3,015	$ 3,010	$ 3,005	$ 36,383

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 4.1-4.3 Recap
JANUARY 2012 - DECEMBER 2012

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Crystal River 4 & 5 (Project 4.2a)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	2,853,179	
3	Less: Accumulated Depreciation		(204,863)	(210,807)	(216,751)	(222,695)	(228,639)	(234,583)	(240,527)	(246,471)	(252,415)	(258,359)	(264,303)	(270,247)	(276,191)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		2,648,316	2,642,372	2,636,428	2,630,484	2,624,540	2,618,596	2,612,652	2,606,708	2,600,764	2,594,820	2,588,876	2,582,932	2,576,988	
6	Average Net Investment			2,645,344	2,639,400	2,633,456	2,627,512	2,621,568	2,615,624	2,609,680	2,603,736	2,597,792	2,591,848	2,585,904	2,579,960	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		17,687	17,648	17,608	17,568	17,528	17,489	17,449	17,409	17,369	17,330	17,290	17,250	209,625
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		6,508	6,494	6,479	6,465	6,450	6,435	6,421	6,406	6,391	6,377	6,362	6,348	77,136
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		5,944	5,944	5,944	5,944	5,944	5,944	5,944	5,944	5,944	5,944	5,944	5,944	71,328
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		1,881	1,881	1,881	1,881	1,881	1,881	1,881	1,881	1,881	1,881	1,881	1,881	22,572
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			32,020	31,967	31,912	31,858	31,803	31,749	31,695	31,640	31,585	31,532	31,477	31,423	380,661
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 32,020	$ 31,967	$ 31,912	$ 31,858	$ 31,803	$ 31,749	$ 31,695	$ 31,640	$ 31,585	$ 31,532	$ 31,477	$ 31,423	$ 380,661

For Project: ABOVE GROUND TANK SECONDARY CONTAINMENT - Higgins (Project 4.1i)
(In Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	394,968	
3	Less: Accumulated Depreciation		(54,444)	(56,221)	(57,998)	(59,775)	(61,552)	(63,329)	(65,106)	(66,883)	(68,660)	(70,437)	(72,214)	(73,991)	(75,768)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		340,524	338,747	336,970	335,193	333,416	331,639	329,862	328,085	326,308	324,531	322,754	320,977	319,200	
6	Average Net Investment			339,635	337,858	336,081	334,304	332,527	330,750	328,973	327,196	325,419	323,642	321,865	320,088	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		2,271	2,259	2,247	2,235	2,223	2,211	2,200	2,188	2,176	2,164	2,152	2,140	26,466
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		836	831	827	822	818	814	809	805	801	796	792	788	9,739
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	5.40%		1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	1,777	21,324
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009370		308	308	308	308	308	308	308	308	308	308	308	308	3,696
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			5,192	5,175	5,159	5,142	5,126	5,110	5,094	5,078	5,062	5,045	5,029	5,013	61,225
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 5,192	$ 5,175	$ 5,159	$ 5,142	$ 5,126	$ 5,110	$ 5,094	$ 5,078	$ 5,062	$ 5,045	$ 5,029	$ 5,013	$ 61,225

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.2 Recap
JANUARY 2012 - DECEMBER 2012

For Project: CAIR CTs - AVON PARK (Project 7.2a)
(in Dollars)

Line Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1 Investments															
a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	161,754	
3 Less: Accumulated Depreciation		(14,249)	(14,653)	(15,057)	(15,461)	(15,865)	(16,269)	(16,673)	(17,077)	(17,481)	(17,885)	(18,289)	(18,693)	(19,097)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		147,505	147,101	146,697	146,293	145,889	145,485	145,081	144,677	144,273	143,869	143,465	143,061	142,657	
6 Average Net Investment			147,303	146,899	146,495	146,091	145,687	145,283	144,879	144,475	144,071	143,667	143,263	142,859	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		985	982	979	977	974	971	969	966	963	961	958	955	11,640
b. Debt Component (Line 6 x Rate x 1/12)	2.95%		362	361	360	359	358	357	356	355	354	353	352	351	4,278
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	3.00%		404	404	404	404	404	404	404	404	404	404	404	404	4,848
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.008940		121	121	121	121	121	121	121	121	121	121	121	121	1,452
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			1,872	1,868	1,864	1,861	1,857	1,853	1,850	1,846	1,842	1,839	1,835	1,831	22,218
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 1,872	$ 1,868	$ 1,864	$ 1,861	$ 1,857	$ 1,853	$ 1,850	$ 1,846	$ 1,842	$ 1,839	$ 1,835	$ 1,831	$ 22,218

For Project: CAIR CTs - BARTOW (Project 7.2b)
(in Dollars)

Line Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1 Investments															
a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	275,347	
3 Less: Accumulated Depreciation		(28,081)	(28,448)	(28,815)	(29,182)	(29,549)	(29,916)	(30,283)	(30,650)	(31,017)	(31,384)	(31,751)	(32,118)	(32,485)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		247,266	246,899	246,532	246,165	245,798	245,431	245,064	244,697	244,330	243,963	243,596	243,229	242,862	
6 Average Net Investment			247,083	246,716	246,349	245,982	245,615	245,248	244,881	244,514	244,147	243,780	243,413	243,046	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		1,652	1,650	1,647	1,645	1,642	1,640	1,637	1,635	1,632	1,630	1,628	1,625	19,663
b. Debt Component (Line 6 x Rate x 1/12)	2.95%		608	607	606	605	604	603	602	602	601	600	599	598	7,235
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	1.60%		367	367	367	367	367	367	367	367	367	367	367	367	4,404
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.009370		215	215	215	215	215	215	215	215	215	215	215	215	2,580
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			2,842	2,839	2,835	2,832	2,828	2,825	2,821	2,819	2,815	2,812	2,809	2,805	33,882
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 2,842	$ 2,839	$ 2,835	$ 2,832	$ 2,828	$ 2,825	$ 2,821	$ 2,819	$ 2,815	$ 2,812	$ 2,809	$ 2,805	$ 33,882

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.2 Recap
JANUARY 2012 - DECEMBER 2012

For Project: CAIR CTs - BAYBORO (Project 7.2c)
(in Dollars)

Line Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1 Investments															
a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	198,988	
3 Less: Accumulated Depreciation		(20,223)	(20,604)	(20,985)	(21,366)	(21,747)	(22,128)	(22,509)	(22,890)	(23,271)	(23,652)	(24,033)	(24,414)	(24,795)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		178,765	178,384	178,003	177,622	177,241	176,860	176,479	176,098	175,717	175,336	174,955	174,574	174,193	
6 Average Net Investment			178,575	178,194	177,813	177,432	177,051	176,670	176,289	175,908	175,527	175,146	174,765	174,384	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		1,194	1,191	1,189	1,186	1,184	1,181	1,179	1,176	1,174	1,171	1,169	1,166	14,160
b. Debt Component (Line 6 x Rate x 1/12)	2.95%		439	438	437	437	436	435	434	433	432	431	430	429	5,211
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	2.30%		381	381	381	381	381	381	381	381	381	381	381	381	4,572
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.009370		155	155	155	155	155	155	155	155	155	155	155	155	1,860
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			2,169	2,165	2,162	2,159	2,156	2,152	2,149	2,145	2,142	2,138	2,135	2,131	25,803
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 2,169	$ 2,165	$ 2,162	$ 2,159	$ 2,156	$ 2,152	$ 2,149	$ 2,145	$ 2,142	$ 2,138	$ 2,135	$ 2,131	$ 25,803

For Project: CAIR CTs - DeBARY (Project 7.2d)
(in Dollars)

Line Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1 Investments															
a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	87,667	
3 Less: Accumulated Depreciation		(11,631)	(11,850)	(12,069)	(12,288)	(12,507)	(12,726)	(12,945)	(13,164)	(13,383)	(13,602)	(13,821)	(14,040)	(14,259)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		76,036	75,817	75,598	75,379	75,160	74,941	74,722	74,503	74,284	74,065	73,846	73,627	73,408	
6 Average Net Investment			75,927	75,708	75,489	75,270	75,051	74,832	74,613	74,394	74,175	73,956	73,737	73,518	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		508	506	505	503	502	500	499	497	496	494	493	492	5,995
b. Debt Component (Line 6 x Rate x 1/12)	2.95%		187	186	186	185	185	184	184	183	182	182	181	181	2,206
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	3.00%		219	219	219	219	219	219	219	219	219	219	219	219	2,628
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.010850		79	79	79	79	79	79	79	79	79	79	79	79	948
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			993	990	989	986	985	982	981	978	976	974	972	971	11,777
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 993	$ 990	$ 989	$ 986	$ 985	$ 982	$ 981	$ 978	$ 976	$ 974	$ 972	$ 971	$ 11,777

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.2 Recap
JANUARY 2012 - DECEMBER 2012

For Project: CAIR CTs - HIGGINS (Project 7.2e)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	347,198	
3	Less: Accumulated Depreciation		(26,769)	(27,608)	(28,447)	(29,286)	(30,125)	(30,964)	(31,803)	(32,642)	(33,481)	(34,320)	(35,159)	(35,998)	(36,837)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		320,429	319,590	318,751	317,912	317,073	316,234	315,395	314,556	313,717	312,878	312,039	311,200	310,361	
6	Average Net Investment			320,009	319,170	318,331	317,492	316,653	315,814	314,975	314,136	313,297	312,458	311,619	310,780	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		2,140	2,134	2,128	2,123	2,117	2,112	2,106	2,100	2,095	2,089	2,084	2,078	25,306
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		787	785	783	781	779	777	775	773	771	769	767	765	9,312
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.90%		839	839	839	839	839	839	839	839	839	839	839	839	10,068
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009370		271	271	271	271	271	271	271	271	271	271	271	271	3,252
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			4,037	4,029	4,021	4,014	4,006	3,999	3,991	3,983	3,976	3,968	3,961	3,953	47,938
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 4,037	$ 4,029	$ 4,021	$ 4,014	$ 4,006	$ 3,999	$ 3,991	$ 3,983	$ 3,976	$ 3,968	$ 3,961	$ 3,953	$ 47,938

For Project: CAIR CTs - INTERCESSION CITY (Project 7.2f)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	349,583	
3	Less: Accumulated Depreciation		(38,347)	(39,134)	(39,921)	(40,708)	(41,495)	(42,282)	(43,069)	(43,856)	(44,643)	(45,430)	(46,217)	(47,004)	(47,791)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		311,237	310,450	309,663	308,876	308,089	307,302	306,515	305,728	304,941	304,154	303,367	302,580	301,793	
6	Average Net Investment			310,843	310,056	309,269	308,482	307,695	306,908	306,121	305,334	304,547	303,760	302,973	302,186	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		2,078	2,073	2,068	2,063	2,057	2,052	2,047	2,042	2,036	2,031	2,026	2,020	24,593
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		765	763	761	759	757	755	753	751	749	747	745	743	9,048
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.70%		787	787	787	787	787	787	787	787	787	787	787	787	9,444
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.008880		259	259	259	259	259	259	259	259	259	259	259	259	3,108
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			3,889	3,882	3,875	3,868	3,860	3,853	3,846	3,839	3,831	3,824	3,817	3,809	46,193
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 3,889	$ 3,882	$ 3,875	$ 3,868	$ 3,860	$ 3,853	$ 3,846	$ 3,839	$ 3,831	$ 3,824	$ 3,817	$ 3,809	$ 46,193

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.2 Recap
JANUARY 2012 - DECEMBER 2012

For Project: CAIR CTs - TURNER (Project 7.2g)
(in Dollars)

Line Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1 Investments															
a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	134,012	
3 Less: Accumulated Depreciation		(10,983)	(11,117)	(11,251)	(11,385)	(11,519)	(11,653)	(11,787)	(11,921)	(12,055)	(12,189)	(12,323)	(12,457)	(12,591)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		123,029	122,895	122,761	122,627	122,493	122,359	122,225	122,091	121,957	121,823	121,689	121,555	121,421	
6 Average Net Investment			122,962	122,828	122,694	122,560	122,426	122,292	122,158	122,024	121,890	121,756	121,622	121,488	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		822	821	820	819	819	818	817	816	815	814	813	812	9,806
b. Debt Component (Line 6 x Rate x 1/12)	2.95%		303	302	302	302	301	301	301	300	300	300	299	299	3,610
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	1.20%		134	134	134	134	134	134	134	134	134	134	134	134	1,608
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.010850		121	121	121	121	121	121	121	121	121	121	121	121	1,452
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			1,380	1,378	1,377	1,376	1,375	1,374	1,373	1,371	1,370	1,369	1,367	1,366	16,476
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 1,380	$ 1,378	$ 1,377	$ 1,376	$ 1,375	$ 1,374	$ 1,373	$ 1,371	$ 1,370	$ 1,369	$ 1,367	$ 1,366	$ 16,476

For Project: CAIR CTs - SUWANNEE (Project 7.2h)
(in Dollars)

Line Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1 Investments															
a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	381,560	
3 Less: Accumulated Depreciation		(25,734)	(26,147)	(26,560)	(26,973)	(27,386)	(27,799)	(28,212)	(28,625)	(29,038)	(29,451)	(29,864)	(30,277)	(30,690)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		355,826	355,413	355,000	354,587	354,174	353,761	353,348	352,935	352,522	352,109	351,696	351,283	350,870	
6 Average Net Investment			355,619	355,206	354,793	354,380	353,967	353,554	353,141	352,728	352,315	351,902	351,489	351,076	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		2,378	2,375	2,372	2,369	2,367	2,364	2,361	2,358	2,356	2,353	2,350	2,347	28,350
b. Debt Component (Line 6 x Rate x 1/12)	2.95%		875	874	873	872	871	870	869	868	867	866	865	864	10,434
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	1.30%		413	413	413	413	413	413	413	413	413	413	413	413	4,956
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.007670		244	244	244	244	244	244	244	244	244	244	244	244	2,928
e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			3,910	3,906	3,902	3,898	3,895	3,891	3,887	3,883	3,880	3,876	3,872	3,868	46,668
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 3,910	$ 3,906	$ 3,902	$ 3,898	$ 3,895	$ 3,891	$ 3,887	$ 3,883	$ 3,880	$ 3,876	$ 3,872	$ 3,868	$ 46,668

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2012 - DECEMBER 2012

For Project: CAIR Crystal River AFUDC - Access Road and Vehicle Barrier System (Project 7.4a)
(in Dollars)

Line Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1 Investments															
a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		17,107,773	17,107,773	17,107,773	17,107,773	17,107,773	17,107,773	17,107,773	17,107,773	17,107,773	17,107,773	17,107,773	17,107,773	17,107,773	
3 Less: Accumulated Depreciation		(1,330,587)	(1,351,972)	(1,373,357)	(1,394,742)	(1,416,127)	(1,437,512)	(1,458,897)	(1,480,282)	(1,501,667)	(1,523,052)	(1,544,437)	(1,565,822)	(1,587,207)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		15,777,187	15,755,802	15,734,417	15,713,032	15,691,647	15,670,262	15,648,877	15,627,492	15,606,107	15,584,722	15,563,337	15,541,952	15,520,567	
6 Average Net Investment			15,766,494	15,745,109	15,723,724	15,702,339	15,680,954	15,659,569	15,638,184	15,616,799	15,595,414	15,574,029	15,552,644	15,531,259	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		105,418	105,275	105,132	104,989	104,846	104,703	104,560	104,417	104,274	104,131	103,988	103,845	1,255,576
b. Debt Component (Line 6 x Rate x 1/12)	2.95%		38,791	38,738	38,685	38,633	38,580	38,527	38,475	38,422	38,370	38,317	38,264	38,212	462,014
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	1.50%		21,386	21,385	21,385	21,385	21,385	21,385	21,385	21,385	21,385	21,385	21,385	21,385	256,620
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.007910		11,277	11,277	11,277	11,277	11,277	11,277	11,277	11,277	11,277	11,277	11,277	11,277	135,324
e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			176,871	176,675	176,479	176,284	176,088	175,892	175,697	175,501	175,306	175,110	174,914	174,719	2,109,536
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 176,871	$ 176,675	$ 176,479	$ 176,284	$ 176,088	$ 175,892	$ 175,697	$ 175,501	$ 175,306	$ 175,110	$ 174,914	$ 174,719	$ 2,109,536

For Project: CAIR Crystal River AFUDC - UNIT 4 LNB/AH (Project 7.4b)
(in Dollars)

Line Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1 Investments															
a. Expenditures/Additions			$ 801,978	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 801,978
b. Clearings to Plant			0	0	0	0	801,978	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		12,374,383	12,374,383	12,374,383	12,374,383	12,374,383	13,176,361	13,176,361	13,176,361	13,176,361	13,176,361	13,176,361	13,176,361	13,176,361	
3 Less: Accumulated Depreciation		(856,397)	(882,177)	(907,957)	(933,737)	(959,517)	(986,132)	(1,013,583)	(1,041,034)	(1,068,485)	(1,095,936)	(1,123,387)	(1,150,838)	(1,178,289)	
4 CWIP - Non-Interest Bearing		(0)	801,978	801,978	801,978	801,978	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		11,517,986	12,294,184	12,268,404	12,242,624	12,216,844	12,190,229	12,162,778	12,135,327	12,107,876	12,080,425	12,052,974	12,025,523	11,998,072	
6 Average Net Investment			11,906,085	12,281,294	12,255,514	12,229,734	12,203,537	12,176,504	12,149,053	12,121,602	12,094,151	12,066,700	12,039,249	12,011,798	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		79,606	82,115	81,943	81,770	81,595	81,414	81,231	81,047	80,864	80,680	80,497	80,313	973,075
b. Debt Component (Line 6 x Rate x 1/12)	2.95%		29,293	30,216	30,152	30,089	30,025	29,958	29,890	29,823	29,755	29,688	29,620	29,553	358,062
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	2.50%		25,780	25,780	25,780	25,780	26,615	27,451	27,451	27,451	27,451	27,451	27,451	27,451	321,882
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.007910		8,157	8,157	8,157	8,157	8,685	8,685	8,685	8,685	8,685	8,685	8,685	8,685	102,108
e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			142,836	146,268	146,032	145,796	146,920	147,508	147,257	147,006	146,755	146,504	146,253	146,002	1,755,137
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 142,836	$ 146,268	$ 146,032	$ 145,796	$ 146,920	$ 147,508	$ 147,257	$ 147,006	$ 146,755	$ 146,504	$ 146,253	$ 146,002	$ 1,755,137

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2012 - DECEMBER 2012

For Project: CAIR Crystal River AFUDC - Selective Catalytic Reduction CR5 (Project 7.4c)
(in Dollars)

Line Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1 Investments															
a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 2,194,271	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 2,194,271
b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	2,194,271	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		95,634,667	95,634,667	95,634,667	95,634,667	95,634,667	95,634,667	95,634,667	95,634,667	95,634,667	95,634,667	95,634,667	97,828,938	97,828,938	
3 Less: Accumulated Depreciation		(6,124,182)	(6,323,421)	(6,522,660)	(6,721,899)	(6,921,138)	(7,120,377)	(7,319,616)	(7,518,855)	(7,718,094)	(7,917,333)	(8,116,572)	(8,318,097)	(8,521,907)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	2,194,271	2,194,271	2,194,271	2,194,271	2,194,271	2,194,271	0	0	
5 Net Investment (Lines 2 + 3 + 4)		89,510,485	89,311,246	89,112,007	88,912,768	88,713,529	90,708,561	90,509,322	90,310,083	90,110,844	89,911,605	89,712,366	89,510,841	89,307,031	
6 Average Net Investment			89,410,866	89,211,627	89,012,388	88,813,149	89,711,045	90,608,942	90,409,703	90,210,464	90,011,225	89,811,986	89,611,604	89,408,936	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		597,817	596,485	595,153	593,821	599,824	605,826	604,496	603,163	601,831	600,499	599,159	597,804	7,195,880
b. Debt Component (Line 6 x Rate x 1/12)	2.95%		219,979	219,488	218,998	218,508	220,717	222,926	222,436	221,946	221,456	220,966	220,473	219,974	2,647,867
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	2.50%		199,239	199,239	199,239	199,239	199,239	199,239	199,239	199,239	199,239	199,239	201,525	203,810	2,397,725
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.007910		63,039	63,039	63,039	63,039	63,039	63,039	63,039	63,039	63,039	63,039	64,486	64,486	759,362
e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			1,080,074	1,078,251	1,076,429	1,074,607	1,082,819	1,091,032	1,089,210	1,087,387	1,085,565	1,083,743	1,085,643	1,086,074	13,000,834
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 1,080,074	$ 1,078,251	$ 1,076,429	$ 1,074,607	$ 1,082,819	$ 1,091,032	$ 1,089,210	$ 1,087,387	$ 1,085,565	$ 1,083,743	$ 1,085,643	$ 1,086,074	$ 13,000,834

For Project: CAIR Crystal River AFUDC - FGD Common (Project 7.4d)
(in Dollars)

Line Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1 Investments															
a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 3,925,000	$ 3,925,000
b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		625,339,441	625,339,441	625,339,441	625,339,441	625,339,441	625,339,441	625,339,441	625,339,441	625,339,441	625,339,441	625,339,441	625,339,441	625,339,441	
3 Less: Accumulated Depreciation		(32,011,719)	(33,314,510)	(34,617,301)	(35,920,092)	(37,222,883)	(38,525,674)	(39,828,465)	(41,131,256)	(42,434,047)	(43,736,838)	(45,039,629)	(46,342,420)	(47,645,211)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	3,925,000	
5 Net Investment (Lines 2 + 3 + 4)		593,327,722	592,024,931	590,722,140	589,419,349	588,116,558	586,813,767	585,510,976	584,208,185	582,906,394	581,602,603	580,299,812	578,997,021	581,619,230	
6 Average Net Investment			592,676,327	591,373,536	590,070,745	588,767,954	587,465,163	586,162,372	584,859,581	583,556,790	582,253,999	580,951,208	579,648,417	580,308,126	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		3,962,741	3,954,031	3,945,320	3,936,609	3,927,898	3,919,188	3,910,477	3,901,766	3,893,056	3,884,345	3,875,634	3,880,045	46,991,110
b. Debt Component (Line 6 x Rate x 1/12)	2.95%		1,458,169	1,454,964	1,451,758	1,448,553	1,445,348	1,442,143	1,438,937	1,435,732	1,432,527	1,429,321	1,426,116	1,427,739	17,291,307
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	2.50%		1,302,791	1,302,791	1,302,791	1,302,791	1,302,791	1,302,791	1,302,791	1,302,791	1,302,791	1,302,791	1,302,791	1,302,791	15,633,492
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.007910		412,203	412,203	412,203	412,203	412,203	412,203	412,203	412,203	412,203	412,203	412,203	412,203	4,946,436
e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			7,135,904	7,123,989	7,112,072	7,100,156	7,088,240	7,076,325	7,064,408	7,052,492	7,040,577	7,028,660	7,016,744	7,022,778	84,862,345
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 7,135,904	$ 7,123,989	$ 7,112,072	$ 7,100,156	$ 7,088,240	$ 7,076,325	$ 7,064,408	$ 7,052,492	$ 7,040,577	$ 7,028,660	$ 7,016,744	$ 7,022,778	$ 84,862,345

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2012 - DECEMBER 2012

For Project: CAIR Crystal River AFUDC - SCR Common Items (Project 7.4e)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	61,260,702	
3	Less: Accumulated Depreciation		(3,858,973)	(3,986,599)	(4,114,225)	(4,241,851)	(4,369,477)	(4,497,103)	(4,624,729)	(4,752,365)	(4,879,981)	(5,007,607)	(5,135,233)	(5,262,859)	(5,390,485)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		57,401,729	57,274,103	57,146,477	57,018,851	56,891,225	56,763,599	56,635,973	56,508,347	56,380,721	56,253,095	56,125,469	55,997,843	55,870,217	
6	Average Net Investment			57,337,916	57,210,290	57,082,664	56,955,038	56,827,412	56,699,786	56,572,160	56,444,534	56,316,908	56,189,282	56,061,656	55,934,030	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		383,372	382,518	381,665	380,812	379,958	379,105	378,252	377,398	376,545	375,692	374,838	373,985	4,544,140
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		141,069	140,755	140,441	140,127	139,813	139,499	139,185	138,871	138,557	138,243	137,929	137,615	1,672,104
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		127,626	127,626	127,626	127,626	127,626	127,626	127,626	127,626	127,626	127,626	127,626	127,626	1,531,512
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		40,381	40,381	40,381	40,381	40,381	40,381	40,381	40,381	40,381	40,381	40,381	40,381	484,572
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			692,448	691,280	690,113	688,946	687,778	686,611	685,444	684,276	683,109	681,942	680,774	679,607	8,232,328
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 692,448	$ 691,280	$ 690,113	$ 688,946	$ 687,778	$ 686,611	$ 685,444	$ 684,276	$ 683,109	$ 681,942	$ 680,774	$ 679,607	$ 8,232,328

For Project: CAIR Crystal River AFUDC - Flue Gas Desulfurization CR5 (Project 7.4f)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		129,959,461	129,959,461	129,959,461	129,959,461	129,959,461	129,959,461	129,959,461	129,959,461	129,959,461	129,959,461	129,959,461	129,959,461	129,959,461	
3	Less: Accumulated Depreciation		(6,803,263)	(7,074,012)	(7,344,761)	(7,615,510)	(7,886,259)	(8,157,008)	(8,427,757)	(8,698,506)	(8,969,255)	(9,240,004)	(9,510,753)	(9,781,502)	(10,052,251)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		123,156,198	122,885,449	122,614,700	122,343,951	122,073,202	121,802,453	121,531,704	121,260,955	120,990,206	120,719,457	120,448,708	120,177,959	119,907,210	
6	Average Net Investment			123,020,824	122,750,075	122,479,326	122,208,577	121,937,828	121,667,079	121,396,330	121,125,581	120,854,832	120,584,083	120,313,334	120,042,585	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		822,540	820,729	818,919	817,109	815,298	813,488	811,678	809,868	808,057	806,247	804,437	802,626	9,750,996
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		302,670	302,004	301,337	300,671	300,005	299,339	298,673	298,007	297,341	296,675	296,008	295,342	3,588,072
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		270,749	270,749	270,749	270,749	270,749	270,749	270,749	270,749	270,749	270,749	270,749	270,749	3,248,988
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		85,665	85,665	85,665	85,665	85,665	85,665	85,665	85,665	85,665	85,665	85,665	85,665	1,027,980
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,481,624	1,479,147	1,476,670	1,474,194	1,471,717	1,469,241	1,466,765	1,464,289	1,461,812	1,459,336	1,456,859	1,454,382	17,616,036
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 1,481,624	$ 1,479,147	$ 1,476,670	$ 1,474,194	$ 1,471,717	$ 1,469,241	$ 1,466,765	$ 1,464,289	$ 1,461,812	$ 1,459,336	$ 1,456,859	$ 1,454,382	$ 17,616,036

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2012 - DECEMBER 2012

For Project: CAIR Crystal River AFUDC - CR5 Sootblower & Intelligent Soot Blowing Controls (Project 7.4g)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		850,198	850,198	850,198	850,198	850,198	850,198	850,198	850,198	850,198	850,198	850,198	850,198	850,198	
3	Less: Accumulated Depreciation		(34,895)	(36,666)	(38,437)	(40,208)	(41,979)	(43,750)	(45,521)	(47,292)	(49,063)	(50,834)	(52,605)	(54,376)	(56,147)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		815,303	813,532	811,761	809,990	808,219	806,448	804,677	802,906	801,135	799,364	797,593	795,822	794,051	
6	Average Net Investment			814,417	812,846	810,875	809,104	807,333	805,562	803,791	802,020	800,249	798,478	796,707	794,936	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		5,445	5,433	5,422	5,410	5,398	5,386	5,374	5,362	5,351	5,339	5,327	5,315	64,562
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		2,004	1,999	1,995	1,991	1,986	1,982	1,978	1,973	1,969	1,965	1,960	1,956	23,758
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		1,771	1,771	1,771	1,771	1,771	1,771	1,771	1,771	1,771	1,771	1,771	1,771	21,252
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		560	560	560	560	560	560	560	560	560	560	560	560	6,720
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			9,780	9,763	9,748	9,732	9,715	9,699	9,683	9,666	9,651	9,635	9,618	9,602	116,292
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 9,780	$ 9,763	$ 9,748	$ 9,732	$ 9,715	$ 9,699	$ 9,683	$ 9,666	$ 9,651	$ 9,635	$ 9,618	$ 9,602	$ 116,292

For Project: CAIR Crystal River AFUDC - CR4 Sootblower & Intelligent Soot Blowing Controls (Project 7.4h)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		917,397	917,397	917,397	917,397	917,397	917,397	917,397	917,397	917,397	917,397	917,397	917,397	917,397	
3	Less: Accumulated Depreciation		(33,339)	(35,250)	(37,161)	(39,072)	(40,983)	(42,894)	(44,805)	(46,716)	(48,627)	(50,538)	(52,449)	(54,360)	(56,271)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		884,059	882,148	880,237	878,326	876,415	874,504	872,593	870,682	868,771	866,860	864,949	863,038	861,127	
6	Average Net Investment			883,103	881,192	879,281	877,370	875,459	873,548	871,637	869,726	867,815	865,904	863,993	862,082	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		5,905	5,892	5,879	5,866	5,853	5,841	5,828	5,815	5,802	5,790	5,777	5,764	70,012
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		2,173	2,168	2,163	2,159	2,154	2,149	2,144	2,140	2,135	2,130	2,126	2,121	25,762
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911	1,911	22,932
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		605	605	605	605	605	605	605	605	605	605	605	605	7,260
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			10,594	10,576	10,558	10,541	10,523	10,506	10,488	10,471	10,453	10,436	10,419	10,401	125,966
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 10,594	$ 10,576	$ 10,558	$ 10,541	$ 10,523	$ 10,506	$ 10,488	$ 10,471	$ 10,453	$ 10,436	$ 10,419	$ 10,401	$ 125,966

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2012 - DECEMBER 2012

For Project: CAIR Crystal River AFUDC - CR4 SCR (Project 7.4i)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 1,626,271	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 1,626,271
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		109,903,942	109,903,942	109,903,942	109,903,942	109,903,942	109,903,942	109,903,942	109,903,942	109,903,942	109,903,942	109,903,942	109,903,942	109,903,942	
3	Less: Accumulated Depreciation		(4,375,713)	(4,604,680)	(4,833,647)	(5,062,614)	(5,291,581)	(5,520,548)	(5,749,515)	(5,978,482)	(6,207,449)	(6,436,416)	(6,665,383)	(6,894,350)	(7,123,317)	
4	CWIP - Non-Interest Bearing		180,000	180,000	180,000	180,000	180,000	1,806,271	1,806,271	1,806,271	1,806,271	1,806,271	1,806,271	1,806,271	1,806,271	
5	Net Investment (Lines 2 + 3 + 4)		105,708,229	105,479,262	105,250,295	105,021,328	104,792,361	106,189,665	105,960,698	105,731,731	105,502,764	105,273,797	105,044,830	104,815,863	104,586,896	
6	Average Net Investment			105,593,745	105,364,778	105,135,811	104,906,844	105,491,013	106,075,181	105,846,214	105,617,247	105,388,280	105,159,313	104,930,346	104,701,379	
7	Return on Average Net Investment															
	b. Equity Component Grossed Up For Taxes	8.02%		706,019	704,488	702,957	701,426	705,332	709,238	707,707	706,176	704,645	703,114	701,583	700,052	8,452,737
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		259,794	259,230	258,667	258,104	259,541	260,978	260,415	259,851	259,288	258,725	258,161	257,598	3,110,352
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		228,967	228,967	228,967	228,967	228,967	228,967	228,967	228,967	228,967	228,967	228,967	228,967	2,747,604
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		72,445	72,445	72,445	72,445	72,445	72,445	72,445	72,445	72,445	72,445	72,445	72,445	869,340
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,267,225	1,265,130	1,263,036	1,260,942	1,266,285	1,271,628	1,269,534	1,267,439	1,265,345	1,263,251	1,261,156	1,259,062	15,180,033
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 1,267,225	$ 1,265,130	$ 1,263,036	$ 1,260,942	$ 1,266,285	$ 1,271,628	$ 1,269,534	$ 1,267,439	$ 1,265,345	$ 1,263,251	$ 1,261,156	$ 1,259,062	$ 15,180,033

For Project: CAIR Crystal River AFUDC - CR4 FGD (Project 7.4j)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		140,130,723	140,130,723	140,130,723	140,130,723	140,130,723	140,130,723	140,130,723	140,130,723	140,130,723	140,130,723	140,130,723	140,130,723	140,130,723	
3	Less: Accumulated Depreciation		(5,605,788)	(5,897,727)	(6,189,666)	(6,481,605)	(6,773,544)	(7,065,483)	(7,357,422)	(7,649,361)	(7,941,300)	(8,233,239)	(8,525,178)	(8,817,117)	(9,109,056)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		134,524,935	134,232,996	133,941,057	133,649,118	133,357,179	133,065,240	132,773,301	132,481,362	132,189,423	131,897,484	131,605,545	131,313,606	131,021,667	
6	Average Net Investment			134,378,966	134,087,027	133,795,088	133,503,149	133,211,210	132,919,271	132,627,332	132,335,393	132,043,454	131,751,515	131,459,576	131,167,637	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		898,482	896,530	894,578	892,626	890,674	888,722	886,770	884,818	882,866	880,914	878,963	877,011	10,652,954
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		330,614	329,896	329,178	328,459	327,741	327,023	326,305	325,586	324,868	324,150	323,432	322,713	3,919,965
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		291,939	291,939	291,939	291,939	291,939	291,939	291,939	291,939	291,939	291,939	291,939	291,939	3,503,268
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		92,370	92,370	92,370	92,370	92,370	92,370	92,370	92,370	92,370	92,370	92,370	92,370	1,108,440
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			1,613,405	1,610,735	1,608,065	1,605,394	1,602,724	1,600,054	1,597,384	1,594,713	1,592,043	1,589,373	1,586,704	1,584,033	19,184,627
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 1,613,405	$ 1,610,735	$ 1,608,065	$ 1,605,394	$ 1,602,724	$ 1,600,054	$ 1,597,384	$ 1,594,713	$ 1,592,043	$ 1,589,373	$ 1,586,704	$ 1,584,033	$ 19,184,627

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2012 - DECEMBER 2012

For Project: CAIR Crystal River AFUDC - Gypsum Handling (Project 7.4k)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	20,988,196	
3	Less: Accumulated Depreciation		(1,074,830)	(1,118,555)	(1,162,280)	(1,206,005)	(1,249,730)	(1,293,455)	(1,337,180)	(1,380,905)	(1,424,630)	(1,468,355)	(1,512,080)	(1,555,805)	(1,599,530)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		19,913,366	19,869,641	19,825,916	19,782,191	19,738,466	19,694,741	19,651,016	19,607,291	19,563,566	19,519,841	19,476,116	19,432,391	19,388,666	
6	Average Net Investment			19,891,504	19,847,779	19,804,054	19,760,329	19,716,604	19,672,879	19,629,154	19,585,429	19,541,704	19,497,979	19,454,254	19,410,529	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		132,998	132,706	132,413	132,121	131,829	131,536	131,244	130,952	130,659	130,367	130,075	129,782	1,576,682
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		48,939	48,832	48,724	48,617	48,509	48,401	48,294	48,186	48,079	47,971	47,864	47,756	580,172
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		43,725	43,725	43,725	43,725	43,725	43,725	43,725	43,725	43,725	43,725	43,725	43,725	524,700
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		13,835	13,835	13,835	13,835	13,835	13,835	13,835	13,835	13,835	13,835	13,835	13,835	166,020
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			239,497	239,098	238,697	238,298	237,898	237,497	237,098	236,698	236,298	235,898	235,499	235,098	2,847,574
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 239,497	$ 239,098	$ 238,697	$ 238,298	$ 237,898	$ 237,497	$ 237,098	$ 236,698	$ 236,298	$ 235,898	$ 235,499	$ 235,098	$ 2,847,574

For Project: CAIR Crystal River AFUDC - CR5 Acid Mist Mitigation Controls (Project 7.4l)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	9,406,705	
3	Less: Accumulated Depreciation		(382,090)	(401,687)	(421,284)	(440,881)	(460,478)	(480,075)	(499,672)	(519,269)	(538,866)	(558,463)	(578,060)	(597,657)	(617,254)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		9,024,615	9,005,018	8,985,421	8,965,824	8,946,227	8,926,630	8,907,033	8,887,436	8,867,839	8,848,242	8,828,645	8,809,048	8,789,451	
6	Average Net Investment			9,014,817	8,995,220	8,975,623	8,956,026	8,936,429	8,916,832	8,897,235	8,877,638	8,858,041	8,838,444	8,818,847	8,799,250	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		60,275	60,144	60,013	59,882	59,751	59,620	59,489	59,357	59,226	59,095	58,964	58,833	714,649
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		22,179	22,131	22,083	22,035	21,986	21,938	21,890	21,842	21,794	21,745	21,697	21,649	262,969
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		19,597	19,597	19,597	19,597	19,597	19,597	19,597	19,597	19,597	19,597	19,597	19,597	235,164
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		6,201	6,201	6,201	6,201	6,201	6,201	6,201	6,201	6,201	6,201	6,201	6,201	74,412
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			108,252	108,073	107,894	107,715	107,535	107,356	107,177	106,997	106,818	106,638	106,459	106,280	1,287,194
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 108,252	$ 108,073	$ 107,894	$ 107,715	$ 107,535	$ 107,356	$ 107,177	$ 106,997	$ 106,818	$ 106,638	$ 106,459	$ 106,280	$ 1,287,194

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2012 - DECEMBER 2012

For Project: CAIR Crystal River AFUDC - FGD Settling Pond (Project 7.4m)
(in Dollars)

Line Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1 Investments															
a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	7,677,316	
3 Less: Accumulated Depreciation		(200,760)	(210,357)	(219,954)	(229,551)	(239,148)	(248,745)	(258,342)	(267,939)	(277,536)	(287,133)	(296,730)	(306,327)	(315,924)	
4 CWIP - Non-Interest Bearing		(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	
5 Net Investment (Lines 2 + 3 + 4)		7,476,556	7,466,959	7,457,362	7,447,765	7,438,168	7,428,571	7,418,974	7,409,377	7,399,780	7,390,183	7,380,586	7,370,989	7,361,392	
6 Average Net Investment			7,471,757	7,462,160	7,452,563	7,442,966	7,433,369	7,423,772	7,414,175	7,404,578	7,394,981	7,385,384	7,375,787	7,366,190	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		49,958	49,893	49,829	49,765	49,701	49,637	49,573	49,508	49,444	49,380	49,316	49,252	595,256
b. Debt Component (Line 6 x Rate x 1/12)	2.95%		18,383	18,359	18,336	18,312	18,288	18,265	18,241	18,218	18,194	18,170	18,147	18,123	219,036
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	1.50%		9,597	9,597	9,597	9,597	9,597	9,597	9,597	9,597	9,597	9,597	9,597	9,597	115,164
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.007910		5,061	5,061	5,061	5,061	5,061	5,061	5,061	5,061	5,061	5,061	5,061	5,061	60,732
e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			82,999	82,910	82,823	82,735	82,647	82,560	82,472	82,384	82,296	82,208	82,121	82,033	990,188
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 82,999	$ 82,910	$ 82,823	$ 82,735	$ 82,647	$ 82,560	$ 82,472	$ 82,384	$ 82,296	$ 82,208	$ 82,121	$ 82,033	$ 990,188

For Project: CAIR Crystal River AFUDC - Coal Pile Runoff Treatment System (Project 7.4n)
(in Dollars)

Line Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1 Investments															
a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2 Plant-in-Service/Depreciation Base		15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	15,969,106	
3 Less: Accumulated Depreciation		(449,036)	(468,997)	(488,958)	(508,919)	(528,880)	(548,841)	(568,802)	(588,763)	(608,724)	(628,685)	(648,646)	(668,607)	(688,568)	
4 CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5 Net Investment (Lines 2 + 3 + 4)		15,520,070	15,500,109	15,480,148	15,460,187	15,440,226	15,420,265	15,400,304	15,380,343	15,360,382	15,340,421	15,320,460	15,300,499	15,280,538	
6 Average Net Investment			15,510,090	15,490,129	15,470,168	15,450,207	15,430,246	15,410,285	15,390,324	15,370,363	15,350,402	15,330,441	15,310,480	15,290,519	
7 Return on Average Net Investment															
a. Equity Component Grossed Up For Taxes	8.02%		103,703	103,570	103,436	103,303	103,169	103,036	102,902	102,769	102,636	102,502	102,369	102,235	1,235,630
b. Debt Component (Line 6 x Rate x 1/12)	2.95%		38,160	38,111	38,061	38,012	37,963	37,914	37,865	37,816	37,767	37,718	37,669	37,619	454,675
c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8 Investment Expenses															
a. Depreciation	1.50%		19,961	19,961	19,961	19,961	19,961	19,961	19,961	19,961	19,961	19,961	19,961	19,961	239,532
b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
d. Property Taxes	0.007910		10,526	10,526	10,526	10,526	10,526	10,526	10,526	10,526	10,526	10,526	10,526	10,526	126,312
e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9 Total System Recoverable Expenses (Lines 7 + 8)			172,350	172,168	171,984	171,802	171,619	171,437	171,254	171,072	170,890	170,707	170,525	170,341	2,056,149
a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
b. Recoverable Costs Allocated to Demand			$ 172,350	$ 172,168	$ 171,984	$ 171,802	$ 171,619	$ 171,437	$ 171,254	$ 171,072	$ 170,890	$ 170,707	$ 170,525	$ 170,341	$ 2,056,149

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 7.4 Recap
JANUARY 2012 - DECEMBER 2012

For Project: CAIR Crystal River AFUDC - Dibasic Acid Additive System (Project 7.4o)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	1,094,418	
3	Less: Accumulated Depreciation		(36,112)	(38,392)	(40,672)	(42,952)	(45,232)	(47,512)	(49,792)	(52,072)	(54,352)	(56,632)	(58,912)	(61,192)	(63,472)	
4	CWIP - Non-Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		1,058,307	1,056,027	1,053,747	1,051,467	1,049,187	1,046,907	1,044,627	1,042,347	1,040,067	1,037,787	1,035,507	1,033,227	1,030,947	
6	Average Net Investment			1,057,167	1,054,887	1,052,607	1,050,327	1,048,047	1,045,767	1,043,487	1,041,207	1,038,927	1,036,647	1,034,367	1,032,087	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		7,068	7,053	7,038	7,023	7,007	6,992	6,977	6,962	6,946	6,931	6,916	6,901	83,814
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		2,601	2,595	2,590	2,584	2,579	2,573	2,567	2,562	2,556	2,550	2,545	2,539	30,841
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	2,280	27,360
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		721	721	721	721	721	721	721	721	721	721	721	721	8,652
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			12,670	12,649	12,629	12,608	12,587	12,566	12,545	12,525	12,503	12,482	12,462	12,441	150,667
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 12,670	$ 12,649	$ 12,629	$ 12,608	$ 12,587	$ 12,566	$ 12,545	$ 12,525	$ 12,503	$ 12,482	$ 12,462	$ 12,441	$ 150,667

For Project: CAIR Crystal River AFUDC - Bottom Ash (PH)/Fly Ash (Ammonia) (Project 7.4p)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 600,000	$ 0	$ 0	$ 2,933,333	$ 2,933,333	$ 2,933,333	$ 0	$ 0	$ 0	$ 3,333,333	$ 3,333,333	$ 3,333,333	$ 19,400,000
	b. Clearings to Plant			600,000	0	0	0	0	10,000,000	0	0	0	0	0	10,000,000	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		37,734	637,734	637,734	637,734	637,734	637,734	10,637,734	10,637,734	10,637,734	10,637,734	10,637,734	10,637,734	20,637,734	
3	Less: Accumulated Depreciation		(439)	(1,030)	(2,146)	(3,262)	(4,378)	(5,494)	(15,360)	(33,976)	(52,592)	(71,208)	(89,824)	(108,440)	(135,806)	
4	CWIP - Non-Interest Bearing		1,200,000	1,200,000	1,200,000	1,200,000	4,133,333	7,066,667	0	0	0	0	3,333,333	6,666,667	0	
5	Net Investment (Lines 2 + 3 + 4)		1,237,295	1,836,704	1,835,588	1,834,472	4,766,690	7,698,907	10,622,374	10,603,758	10,585,142	10,566,526	13,881,244	17,195,961	20,501,928	
6	Average Net Investment			1,537,000	1,836,146	1,835,030	3,300,581	6,232,798	9,160,641	10,613,066	10,594,450	10,575,834	12,223,885	15,538,602	18,848,945	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		10,277	12,277	12,269	22,068	41,674	61,250	70,961	70,836	70,712	81,731	103,894	126,027	683,976
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		3,782	4,517	4,515	8,120	15,335	22,538	26,111	26,066	26,020	30,075	38,230	46,374	251,683
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.10%		591	1,116	1,116	1,116	1,116	9,866	18,616	18,616	18,616	18,616	18,616	27,366	135,367
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.007910		420	420	420	420	420	7,012	7,012	7,012	7,012	7,012	7,012	13,604	57,776
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			15,070	18,330	18,320	31,724	58,545	100,666	122,700	122,530	122,360	137,434	167,752	213,371	1,128,802
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 15,070	$ 18,330	$ 18,320	$ 31,724	$ 58,545	$ 100,666	$ 122,700	$ 122,530	$ 122,360	$ 137,434	$ 167,752	$ 213,371	$ 1,128,802

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Capital Program Detail Support - Project 11.1 Recap
JANUARY 2012 - DECEMBER 2012

For Project: Crystal River Thermal Discharge Compliance Project AFUDC - Point of Discharge (POD) Cooling Tower (Project 11.1a)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation		0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		0	0	0	0	0	0	0	0	0	0	0	0	0	
6	Average Net Investment Eligible for Return			0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	2.50%		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009790		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			0	0	0	0	0	0	0	0	0	0	0	0	0
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0

For Project: Crystal River Thermal Discharge Compliance Project AFUDC - MET Tower (Project 11.1b)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan-12	Projected Feb-12	Projected Mar-12	Projected Apr-12	Projected May-12	Projected Jun-12	Projected Jul-12	Projected Aug-12	Projected Sep-12	Projected Oct-12	Projected Nov-12	Projected Dec-12	End of Period Total
1	Investments															
	a. Expenditures/Additions			$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other			0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base		361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	
3	Less: Accumulated Depreciation		(14,722)	(15,234)	(15,746)	(16,258)	(16,770)	(17,282)	(17,794)	(18,306)	(18,818)	(19,330)	(19,842)	(20,354)	(20,866)	
4	CWIP - Interest Bearing		0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)		347,014	346,502	345,990	345,478	344,966	344,454	343,942	343,430	342,918	342,406	341,894	341,382	340,870	
6	Average Net Investment Eligible for Return			346,758	346,246	345,734	345,222	344,710	344,198	343,686	343,174	342,662	342,150	341,638	341,126	
7	Return on Average Net Investment															
	a. Equity Component Grossed Up For Taxes	8.02%		2,318	2,315	2,312	2,308	2,305	2,301	2,298	2,295	2,291	2,288	2,284	2,281	27,596
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		853	852	851	849	848	847	846	844	843	842	841	839	10,155
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation	1.70%		512	512	512	512	512	512	512	512	512	512	512	512	6,144
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes	0.009790		295	295	296	295	295	296	295	296	295	296	296	295	3,540
	e. Property Insurance			0	0	0	0	0	0	0	0	0	0	0	0	0
	f. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			3,978	3,974	3,970	3,964	3,960	3,955	3,951	3,946	3,941	3,937	3,932	3,927	47,435
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			$ 3,978	$ 3,974	$ 3,970	$ 3,964	$ 3,960	$ 3,955	$ 3,951	$ 3,946	$ 3,941	$ 3,937	$ 3,932	$ 3,927	$ 47,435

Docket No. 110007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No. __ (TGF-4)

Witness: T.G. Foster
Exhibit__(TGF -5)

PROGRESS ENERGY FLORIDA, INC.
ENVIRONMENTAL COST RECOVERY
COMMISSION FORM 42-8E Page 15, Revised

JANUARY 2011 - DECEMBER 2011
Calculation of the Return on Capital Investments, Depreciation and Taxes for Project 11.1
January through December 2011
DOCKET NO. 110007-EI

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI EXHIBIT 30
PARTY PROGRESS ENERGY FLORIDA
DESCRIPTION THOMAS G. FOSTER (TGF-5)
DATE 11/01/11

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated/Actual Amount
January 2011 through December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Crystal River Thermal Discharge Compliance Project - AFUDC - Base (Project 11.1)
(in Dollars)

Line	Description		Beginning of Period Amount	Actual January 11	Actual February 11	Actual March 11	Actual April 11	Actual May 11	Actual June 11	Estimated July 11	Estimated August 11	Estimated September 11	Estimated October 11	Estimated November 11	Estimated December 11	End of Period Total
1	Investments															
	a. Expenditures/Additions (H)			$ (633,112)	$ 6,795	$ 308,002	$ 20,118	$ 12,435	$ 9,195	$ 0	$ 0	$ 0	$ 0	$ 0	$ 0	$ (276,567)
	b. Clearings to Plant			0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements			0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other (A)			85,539	92,074	93,858	95,352	96,041	96,709	97,315	97,918	98,525	99,135	99,749	100,367	1,152,581
2	Plant-in-Service/Depreciation Base		361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	361,735	
3	Less: Accumulated Depreciation		(8,578)	(9,090)	(9,602)	(10,114)	(10,626)	(11,138)	(11,650)	(12,162)	(12,674)	(13,186)	(13,698)	(14,210)	(14,722)	
4	CWIP - AFUDC Bearing		15,421,367	14,873,794	14,972,663	15,374,523	15,489,992	15,598,468	15,704,372	15,801,687	15,899,605	15,998,129	16,097,264	16,197,014	16,297,381	
5	Net Investment (Lines 2 + 3 + 4)		15,774,525	15,226,440	15,324,796	15,726,144	15,841,102	15,949,066	16,054,458	16,151,260	16,248,666	16,346,679	16,445,302	16,544,539	16,644,395	
6	Average Net Investment (B)			352,902	352,390	351,878	351,366	350,854	350,342	349,830	349,318	348,806	348,294	347,782	347,270	
7	Return on Average Net Investment (C)															
	a. Equity Component Grossed Up For Taxes	8.02%		2,360	2,356	2,353	2,349	2,346	2,342	2,339	2,336	2,332	2,329	2,325	2,322	28,089
	b. Debt Component (Line 6 x 2.95% x 1/12)	2.95%		868	867	866	864	863	862	861	859	858	857	856	854	10,335
	c. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses															
	a. Depreciation (D)			512	512	512	512	512	512	512	512	512	512	512	512	6,144
	b. Amortization			0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	d. Property Taxes (E)			295	295	295	295	295	295	295	295	295	295	295	295	3,540
	e. Other			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)			4,035	4,030	4,026	4,020	4,016	4,011	4,007	4,002	3,997	3,993	3,988	3,983	48,108
	a. Recoverable Costs Allocated to Energy			0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand			4,035	4,030	4,026	4,020	4,016	4,011	4,007	4,002	3,997	3,993	3,988	3,983	48,108
10	Energy Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Demand Jurisdictional Factor - Production (Base)			0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	
12	Retail Energy-Related Recoverable Costs (F)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (G)			3,744	3,740	3,736	3,730	3,727	3,722	3,718	3,714	3,709	3,705	3,701	3,696	44,640
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)			$ 3,744	$ 3,740	$ 3,736	$ 3,730	$ 3,727	$ 3,722	$ 3,718	$ 3,714	$ 3,709	$ 3,705	$ 3,701	$ 3,696	$ 44,640

Notes:
(A) AFUDC rate reflected within Docket 100134-EI per Order PSC-10-0604-PAA-EI.
(B) Line represents the Average Net Investment excluding AFUDC interest-bearing CWIP projects. Refer to Capital Program Detail for Average Net Investment Return on which Line 7 is calculated.
(C) Weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (inc tax multiplier = 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI.
(D) Depreciation calculated only on assets placed in-service which appear in CR Thermal Discharge Project section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Depreciation Rate based on approved rates in Order PSC-10-0131-FOF-EI.
(E) Property taxes calculated only on assets placed in-service which appear in CR Thermal Discharge Project section of Capital Program Detail file. Calculated on that schedule as Line 2 x rate x 1/12. Based on 2010 Effective Tax Rate on original cost.
(F) Line 9a x Line 10
(G) Line 9b x Line 11
(H) Cost estimates will be impacted by both the final form of new environmental regulations and the repair plant and timeing of completing Crystal River Unit 3 delamination work. Accordingly, these costs cannot be accurately predicted at this time. For this reason, PEF is not presently estimating spend beyond June 2011.

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TAMPA ELECTRIC COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE

FINAL TRUE-UP AMOUNT FOR THE PERIOD OF JANUARY 2010 THROUGH DECEMBER 2010

FORMS 42-1A THROUGH 42-9A

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI EXHIBIT 31
PARTY TAMPA ELECTRIC CO. (DIRECT)
DESCRIPTION HOWARD T. BRYANT (HTB-1)
DATE 11/01/11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010
(in Dollars)

Form 42 - 1A

Line		Period Amount
1.	End of Period Actual True-Up for the Period January 2010 to December 2010 (Form 42-2A, Lines 5 + 6 + 10)	$539,002
2.	Estimated/Actual True-Up Amount Approved for the Period January 2010 to December 2010 (Order No. PSC-10-0683 FOF-EI)	3,155,800
3	Final True-Up to be Refunded/(Recovered) in the Projection Period January 2012 to December 2012 (Lines 1 - 2)	($2,616,798)

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DOCKET NO. 110007-EI
ECRC 2010 FINAL TRUE-UP
EXHIBIT HTB-1, DOC. NO. 1, PAGE 1 OF 1

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Form 42 - 2A

Current Period True-Up Amount
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	ECRC Revenues (net of Revenue Taxes)	$7,934,894	$7,069,607	$6,921,761	$6,444,462	$7,270,720	$8,864,432	$8,906,899	$9,331,985	$8,875,143	$7,738,490	$6,691,865	$6,910,607	$92,960,865
2.	True-Up Provision	(1,449,344)	(1,449,344)	(1,449,344)	(1,449,344)	(1,449,344)	(1,449,344)	(1,449,344)	(1,449,344)	(1,449,344)	(1,449,344)	(1,449,344)	(1,449,338)	(17,392,122)
3.	ECRC Revenues Applicable to Period (Lines 1 + 2)	6,485,550	5,620,263	5,472,417	4,995,118	5,821,376	7,415,088	7,457,555	7,882,641	7,425,799	6,289,146	5,242,521	5,461,269	75,568,743
4.	Jurisdictional ECRC Costs													
	a. O & M Activities (Form 42-5A, Line 9)	1,237,979	1,197,584	1,529,017	1,667,263	1,494,195	1,453,642	1,665,003	1,532,685	1,825,290	1,963,719	1,433,174	1,809,349	18,808,900
	b. Capital Investment Projects (Form 42-7A, Line 9)	4,029,769	4,052,084	4,053,214	4,375,897	4,975,629	4,973,761	4,978,926	4,974,786	5,000,022	5,024,067	5,020,303	4,946,027	56,404,485
	c. Total Jurisdictional ECRC Costs	5,267,748	5,249,668	5,582,231	6,043,160	6,469,824	6,427,403	6,643,929	6,507,471	6,825,312	6,987,786	6,453,477	6,755,376	75,213,385
5.	Over/Under Recovery (Line 3 - Line 4c)	1,217,802	370,595	(109,814)	(1,048,042)	(648,448)	967,685	813,626	1,375,170	600,487	(698,640)	(1,210,956)	(1,294,107)	355,358
6.	Interest Provision (Form 42-3A, Line 10)	(2,589)	(2,208)	(2,054)	(1,897)	(2,386)	(2,414)	(1,554)	(790)	(220)	84	188	271	(15,569)
7.	Beginning Balance True-Up & Interest Provision	(17,392,122)	(14,727,565)	(12,909,834)	(11,572,358)	(11,172,953)	(10,374,443)	(7,939,828)	(5,678,412)	(2,854,688)	(805,077)	(54,289)	184,287	(17,392,122)
	a. Deferred True-Up from January to December 2009 (Order No. PSC-10-0683-FOF-EI)	831,312	831,312	831,312	831,312	831,312	831,312	831,312	831,312	831,312	831,312	831,312	831,312	831,312
8.	True-Up Collected/(Refunded) (see Line 2)	1,449,344	1,449,344	1,449,344	1,449,344	1,449,344	1,449,344	1,449,344	1,449,344	1,449,344	1,449,344	1,449,344	1,449,338	17,392,122
9.	End of Period Total True-Up (Lines 5+6+7+7a+8)	(13,896,253)	(12,078,522)	(10,741,046)	(10,341,641)	(9,543,131)	(7,108,516)	(4,847,100)	(2,023,376)	26,235	777,023	1,015,599	1,171,101	1,171,101
10.	Adjustment to Period True-Up Including Interest	0	0	0	0	0	0	0	0	0	0	0	199,213	199,213
11.	End of Period Total True-Up (Lines 9 + 10)	($13,896,253)	($12,078,522)	($10,741,046)	($10,341,641)	($9,543,131)	($7,108,516)	($4,847,100)	($2,023,376)	$26,235	$777,023	$1,015,599	$1,370,314	$1,370,314

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DOCKET NO. 110007-EI
ECRC 2010 FINAL TRUE-UP
EXHIBIT HTB-1, DOC. NO. 2, PAGE 1 OF 1

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Form 42 - 3A

Interest Provision
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Beginning True-Up Amount (Form 42-2A, Line 7 + 7a + 10)	($16,560,810)	($13,896,253)	($12,078,522)	($10,741,046)	($10,341,641)	($9,543,131)	($7,108,516)	($4,847,100)	($2,023,376)	$26,235	$777,023	$1,214,812	
2.	Ending True-Up Amount Before Interest	(13,893,664)	(12,076,314)	(10,738,992)	(10,339,744)	(9,540,745)	(7,106,102)	(4,845,546)	(2,022,586)	26,455	776,939	1,015,411	1,370,043	
3.	Total of Beginning & Ending True-Up (Lines 1 + 2)	(30,454,474)	(25,972,567)	(22,817,514)	(21,080,790)	(19,882,386)	(16,649,233)	(11,954,062)	(6,869,686)	(1,996,921)	803,174	1,792,434	2,584,855	
4.	Average True-Up Amount (Line 3 x 1/2)	(15,227,237)	(12,986,284)	(11,408,757)	(10,540,395)	(9,941,193)	(8,324,617)	(5,977,031)	(3,434,843)	(998,461)	401,587	896,217	1,292,428	
5.	Interest Rate (First Day of Reporting Business Month)	0.20%	0.20%	0.21%	0.21%	0.23%	0.34%	0.35%	0.28%	0.28%	0.25%	0.25%	0.25%	
6.	Interest Rate (First Day of Subsequent Business Month)	0.20%	0.21%	0.21%	0.23%	0.34%	0.35%	0.28%	0.28%	0.25%	0.25%	0.25%	0.25%	
7.	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	0.40%	0.41%	0.42%	0.44%	0.57%	0.69%	0.63%	0.56%	0.53%	0.50%	0.50%	0.50%	
8.	Average Interest Rate (Line 7 x 1/2)	0.200%	0.205%	0.210%	0.220%	0.285%	0.345%	0.315%	0.280%	0.265%	0.250%	0.250%	0.250%	
9.	Monthly Average Interest Rate (Line 8 x 1/12)	0.017%	0.017%	0.018%	0.018%	0.024%	0.029%	0.026%	0.023%	0.022%	0.021%	0.021%	0.021%	
10.	Interest Provision for the Month (Line 4 x Line 9)	($2,589)	($2,208)	($2,054)	($1,897)	($2,386)	($2,414)	($1,554)	($790)	($220)	$84	$188	$271	($15,569)

DOCKET NO. 110007-EI
ECRC 2010 FINAL TRUE-UP
EXHIBIT HTB-1, DOC. NO. 3, PAGE 1 OF 1

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Variance Report of O & M Activities
(In Dollars)

Line		(1) Actual	(2) Actual/Estimated Projection	(3) Variance Amount	(4) Variance Percent
1.	Description of O&M Activities				
	a. Big Bend Unit 3 Flue Gas Desulfurization Integration	$5,067,213	$4,115,482	$951,731	23.1%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0.0%
	c. SO_2 Emissions Allowances	(40,705)	137,684	(178,389)	-129.6%
	d. Big Bend Units 1 & 2 FGD	8,415,387	7,648,553	766,834	10.0%
	e. Big Bend PM Minimization and Monitoring	448,711	436,889	11,822	2.7%
	f. Big Bend NO_x Emissions Reduction	366,609	469,137	(102,528)	-21.9%
	g. NPDES Annual Surveillance Fees	34,500	34,500	0	0.0%
	h. Gannon Thermal Discharge Study	5,029	20,000	(14,971)	-74.9%
	i. Polk NO_x Emissions Reduction	(151,710)	(139,797)	(11,913)	8.5%
	j. Bayside SCR Consumables	101,628	114,898	(13,270)	-11.5%
	k. Big Bend Unit 4 SOFA	61,525	61,525	0	0.0%
	l. Big Bend Unit 1 Pre-SCR	22,165	22,165	0	0.0%
	m. Big Bend Unit 2 Pre-SCR	0	0	0	NA
	n. Big Bend Unit 3 Pre-SCR	9,302	0	9,302	NA
	o. Clean Water Act Section 316(b) Phase II Study	6,042	42,765	(36,723)	-85.9%
	p. Arsenic Groundwater Standard Program	106,584	58,790	47,794	81.3%
	q. Big Bend 1 SCR	1,107,980	923,808	184,172	19.9%
	r. Big Bend 2 SCR	1,267,757	1,279,925	(12,168)	-1.0%
	s. Big Bend 3 SCR	1,378,262	1,359,000	19,262	1.4%
	t. Big Bend 4 SCR	711,365	1,199,231	(487,866)	-40.7%
	u. Clean Air Mercury Rule	116,804	103,159	13,645	13.2%
	v. Greenhouse Gas Reduction Program	58,506	158,405	(99,899)	-63.1%
2.	Total Investment Projects - Recoverable Costs	$19,092,954	$18,046,119	$1,046,835	5.8%
3.	Recoverable Costs Allocated to Energy	$18,940,799	$17,890,064	$1,050,735	5.9%
4.	Recoverable Costs Allocated to Demand	$152,155	$156,055	($3,900)	-2.5%

Notes:
Column (1) is the End of Period Totals on Form 42-5A.
Column (2) is the approved projected amount in accordance with Order No. PSC-10-0683-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

DOCKET NO. 110007-EI
ECRC 2010 FINAL TRUE-UP
EXHIBIT HTB-1, DOC. NO. 4, PAGE 1 OF 1

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

O&M Activities
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	Description of O&M Activities															
a.	Big Bend Unit 3 Flue Gas Desulfurization Integration	$315,192	$179,923	$345,222	$553,136	$405,290	$323,300	$499,027	$433,134	$508,604	$675,173	$392,011	$437,201	$5,067,213		$5,067,213
b.	Big Bend Units 1 & 2 Flue Gas Conditioning													0		0
c.	SO_2 Emissions Allowances	1,756	464	1,648	(47,299)	445	370	704	(140)	262	882	(154)	357	(40,705)		(40,705)
d.	Big Bend Units 1 & 2 FGD	764,671	655,418	767,670	759,197	474,783	538,969	770,960	669,343	929,063	767,642	597,007	720,664	8,415,387		8,415,387
e.	Big Bend PM Minimization and Monitoring	38,460	34,370	15,421	15,424	109,132	26,186	39,788	15,571	27,237	57,926	16,117	53,078	448,711		448,711
f.	Big Bend NO_x Emissions Reduction	12,140	137,071	84,054	10,728	1,438	33,706	2,084	11,516	29,400	29,470	15,002	0	366,609		366,609
g.	NPDES Annual Surveillance Fees	34,500	0	0	0	0	0	0	0	0	0	0	0	34,500	34,500	
h.	Gannon Thermal Discharge Study	(557)	557	0	0	0	0	0	0	0	0	0	5,029	5,029	5,029	
i.	Polk NO_x Reduction	206	(201,460)	10,338	3,887	13,364	9,368	(1,908)	4,355	5,742	1,859	1,044	1,496	(151,710)		(151,710)
j.	Bayside SCR and Ammonia	0	18,752	8,822	0	10,870	21,227	0	10,734	9,154	10,987	11,082	0	101,628		101,628
k.	Big Bend Unit 4 SOFA	0	0	0	0	53,806	7,720	0	0	0	0	0	0	61,525		61,525
l.	Big Bend Unit 1 Pre-SCR	8,220	13,079	1,079	(1,183)	0	971	0	0	0	0	0	0	22,165		22,165
m.	Big Bend Unit 2 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
n.	Big Bend Unit 3 Pre-SCR	0	0	0	0	0	0	0	0	0	8,928	173	200	9,302		9,302
o.	Clean Water Act Section 316(b) Phase II Study	0	1,743	1,022	0	0	0	0	777	625	0	0	1,875	6,042	6,042	
p.	Arsenic Groundwater Standard Program	54	21,500	75	5,278	3,884	0	24,119	11,288	1,299	11,806	60	27,221	106,584	106,584	
q.	Big Bend 1 SCR	0	0	0	6,955	136,216	127,028	150,357	153,232	84,498	129,739	143,791	176,163	1,107,980		1,107,980
r.	Big Bend 2 SCR	30,944	94,237	127,345	134,257	111,597	144,770	89,240	94,819	76,880	79,465	97,831	186,373	1,267,757		1,267,757
s.	Big Bend 3 SCR	51,614	185,061	126,478	156,086	98,044	86,024	77,860	89,533	136,105	117,254	97,237	156,966	1,378,262		1,378,262
t.	Big Bend 4 SCR	5,950	73,203	58,657	82,208	107,867	32,129	39,477	47,964	38,815	85,582	66,206	73,308	711,365		711,365
u.	Clean Air Mercury Rule	0	0	0	0	43	101,616	0	17,027	0	0	0	(1,882)	116,804		116,804
v.	Greenhouse Gas Reduction Program	0	0	0	0	0	32,305	8,479	4,080	1,307	0	3,952	8,383	58,506		58,506
2.	Total of O&M Activities	1,263,150	1,213,918	1,547,832	1,678,674	1,526,778	1,485,686	1,700,187	1,563,233	1,848,991	1,976,713	1,441,359	1,846,433	19,092,954	$152,155	$18,940,799
3.	Recoverable Costs Allocated to Energy	1,229,153	1,190,118	1,546,736	1,673,396	1,522,894	1,485,686	1,676,068	1,551,168	1,847,067	1,964,907	1,441,299	1,812,307	18,940,799		
4.	Recoverable Costs Allocated to Demand	33,997	23,800	1,096	5,278	3,884	0	24,119	12,065	1,924	11,806	60	34,126	152,155		
5.	Retail Energy Jurisdictional Factor	0.9805185	0.9869957	0.9878612	0.9932946	0.9786963	0.9784317	0.9795263	0.9805871	0.9872055	0.9936031	0.9943227	0.9802158			
6.	Retail Demand Jurisdictional Factor	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735			
7.	Jurisdictional Energy Recoverable Costs (A)	1,205,207	1,174,641	1,527,960	1,662,175	1,490,451	1,453,642	1,641,753	1,521,055	1,823,435	1,952,338	1,433,116	1,776,452	18,662,225		
8.	Jurisdictional Demand Recoverable Costs (B)	32,772	22,943	1,057	5,088	3,744	0	23,250	11,630	1,855	11,381	58	32,897	146,675		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,237,979	$1,197,584	$1,529,017	$1,667,263	$1,494,195	$1,453,642	$1,665,003	$1,532,685	$1,825,290	$1,963,719	$1,433,174	$1,809,349	$18,808,900		

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

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DOCKET NO. 110007-EI
ECRC 2010 FINAL TRUE-UP
EXHIBIT HTB-1, DOC. NO. 5, PAGE 1 OF 1

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Form 42 - 6A

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

Line		(1) Actual	(2) Actual/Estimated Projection	(3) Variance Amount	(4) Percent
1.	Description of Investment Projects				
	a. Big Bend Unit 3 Flue Gas Desulfurization Integration	$764,341	$764,341	$0	0.0%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	422,124	422,124	0	0.0%
	c. Big Bend Unit 4 Continuous Emissions Monitors	78,510	78,510	0	0.0%
	d. Big Bend Fuel Oil Tank # 1 Upgrade	53,079	53,079	0	0.0%
	e. Big Bend Fuel Oil Tank # 2 Upgrade	87,302	87,302	0	0.0%
	f. Phillips Upgrade Tank # 1 for FDEP	5,667	5,667	0	0.0%
	g. Phillips Upgrade Tank # 4 for FDEP	8,899	8,899	0	0.0%
	h. Big Bend Unit 1 Classifier Replacement	133,795	133,795	0	0.0%
	i. Big Bend Unit 2 Classifier Replacement	96,974	96,974	0	0.0%
	j. Big Bend Section 114 Mercury Testing Platform	13,303	13,303	0	0.0%
	k. Big Bend Units 1 & 2 FGD	8,731,551	8,724,524	7,027	0.1%
	l. Big Bend FGD Optimization and Utilization	2,475,526	2,475,526	0	0.0%
	m. Big Bend NO_x Emissions Reduction	794,917	796,466	(1,549)	-0.2%
	n. Big Bend PM Minimization and Monitoring	1,075,519	1,082,908	(7,389)	-0.7%
	o. Polk NO_x Emissions Reduction	195,609	195,609	0	0.0%
	p. Big Bend Unit 4 SOFA	317,962	317,962	0	0.0%
	q. Big Bend Unit 1 Pre-SCR	224,634	267,482	(42,848)	-16.0%
	r. Big Bend Unit 2 Pre-SCR	213,590	213,590	0	0.0%
	s. Big Bend Unit 3 Pre-SCR	366,931	366,931	0	0.0%
	t. Big Bend Unit 1 SCR	8,201,186	8,256,118	(54,932)	-0.7%
	u. Big Bend Unit 2 SCR	12,792,226	12,790,727	1,499	0.0%
	v. Big Bend Unit 3 SCR	10,462,778	10,460,882	1,896	0.0%
	w. Big Bend Unit 4 SCR	8,054,753	7,869,338	185,415	2.4%
	x. Big Bend FGD System Reliability	1,534,108	1,534,108	0	0.0%
	y. Clean Air Mercury Rule	166,224	166,207	17	0.0%
	z. $S0_2$ Emissions Allowances	(4,765)	(4,759)	(6)	0.1%
2.	Total Investment Projects - Recoverable Costs	$57,266,743	$57,177,613	$89,130	0.2%
3.	Recoverable Costs Allocated to Energy	$57,111,796	$57,022,666	$89,130	0.2%
4.	Recoverable Costs Allocated to Demand	$154,947	$154,947	$0	0.0%

Notes:
Column (1) is the End of Period Totals on Form 42-7A.
Column (2) is the approved projected amount in accordance with Order No. PSC-10-0683-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

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DOCKET NO. 110007-EI
ECRC 2010 FINAL TRUE-UP
EXHIBIT HTB-1, DOC. NO. 6, PAGE 1 OF 1

Form 42-7A

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Capital Investment Projects-Recoverable Costs

(in Dollars)

Line		Description (A)	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	a.	Big Bend Unit 3 Flue Gas Desulfurization Integration	$64,538	$64,385	$64,232	$64,079	$63,925	$63,771	$63,619	$63,465	$63,312	$63,158	$63,005	$62,852	$764,341		$764,341
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	35,893	35,763	35,632	35,503	35,373	35,242	35,112	34,981	34,852	34,721	34,591	34,461	422,124		422,124
	c.	Big Bend Unit 4 Continuous Emissions Monitors	6,623	6,609	6,594	6,579	6,565	6,550	6,535	6,520	6,506	6,491	6,476	6,462	78,510		78,510
	d.	Big Bend Fuel Oil Tank # 1 Upgrade	4,480	4,471	4,460	4,450	4,439	4,428	4,418	4,408	4,397	4,387	4,376	4,365	53,079	$ 53,079	
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	7,370	7,352	7,335	7,319	7,301	7,284	7,267	7,249	7,232	7,215	7,197	7,181	87,302	87,302	
	f.	Phillips Upgrade Tank # 1 for FDEP	480	478	477	476	474	473	472	470	469	468	466	464	5,667	5,667	
	g.	Phillips Upgrade Tank # 4 for FDEP	754	751	750	747	745	743	740	738	736	734	731	730	8,899	8,899	
	h.	Big Bend Unit 1 Classifier Replacement	11,343	11,308	11,273	11,237	11,202	11,167	11,132	11,097	11,062	11,027	10,991	10,956	133,795		133,795
	i.	Big Bend Unit 2 Classifier Replacement	8,217	8,193	8,167	8,143	8,118	8,094	8,069	8,044	8,019	7,995	7,970	7,945	96,974		96,974
	j.	Big Bend Section 114 Mercury Testing Platform	1,119	1,116	1,115	1,114	1,111	1,110	1,107	1,106	1,103	1,102	1,100	1,098	13,303		13,303
	k.	Big Bend Units 1 & 2 FGD	732,122	731,583	730,183	728,286	732,413	730,345	728,344	726,313	724,282	722,676	721,846	723,158	8,731,551		8,731,551
	l.	Big Bend FGD Optimization and Utilization	208,518	208,113	207,709	207,304	206,901	206,496	206,092	205,687	205,283	204,879	204,474	204,070	2,475,526		2,475,526
	m.	Big Bend NO_x Emissions Reduction	66,387	66,302	66,218	66,133	66,052	65,961	66,197	66,532	66,429	66,314	66,229	66,143	794,917		794,917
	n.	Big Bend PM Minimization and Monitoring	89,648	89,445	89,316	89,223	89,502	89,870	89,923	89,925	89,807	89,747	89,672	89,441	1,075,519		1,075,519
	o.	Polk NO_x Emissions Reduction	16,537	16,494	16,451	16,408	16,365	16,323	16,279	16,236	16,193	16,150	16,108	16,065	195,609		195,609
	p.	Big Bend Unit 4 SOFA	26,770	26,720	26,671	26,621	26,572	26,521	26,472	26,422	26,373	26,323	26,274	26,223	317,962		317,962
	q.	Big Bend Unit 1 Pre-SCR	18,962	18,916	18,874	18,830	18,786	18,742	18,697	18,653	18,609	18,565	18,521	18,477	224,634		224,634
	r.	Big Bend Unit 2 Pre-SCR	18,017	17,978	17,938	17,898	17,859	17,819	17,779	17,740	17,700	17,660	17,621	17,581	213,590		213,590
	s.	Big Bend Unit 3 Pre-SCR	30,888	30,832	30,774	30,718	30,662	30,606	30,550	30,493	30,436	30,380	30,324	30,268	366,931		366,931
	t.	Big Bend Unit 1 SCR	0	0	0	302,889	978,691	985,449	992,411	989,919	989,429	988,456	987,470	986,472	8,201,186		8,201,186
	u.	Big Bend Unit 2 SCR	1,076,522	1,073,783	1,072,371	1,070,673	1,068,819	1,066,923	1,065,026	1,063,237	1,061,338	1,059,487	1,057,741	1,056,304	12,792,226		12,792,226
	v.	Big Bend Unit 3 SCR	879,439	878,039	876,640	875,239	873,840	872,440	871,041	869,640	868,241	866,841	865,452	865,926	10,462,778		10,462,778
	w.	Big Bend Unit 4 SCR	662,942	664,865	668,047	674,022	676,719	675,763	674,705	673,647	672,592	671,538	670,484	669,429	8,054,753		8,054,753
	x.	Big Bend FGD System Reliability	129,032	128,816	128,600	128,383	128,167	127,950	127,734	127,518	127,302	127,085	126,869	126,652	1,534,108		1,534,108
	y.	Clean Air Mercury Rule	13,859	13,865	13,909	13,948	13,930	13,901	13,873	13,845	13,817	13,787	13,759	13,731	166,224		166,224
	z.	SO_2 Emissions Allowances (B)	(405)	(404)	(402)	(401)	(400)	(398)	(397)	(395)	(393)	(392)	(390)	(388)	(4,765)		(4,765)
2.		Total Investment Projects - Recoverable Costs	4,110,055	4,105,777	4,103,334	4,405,821	5,084,131	5,083,593	5,083,199	5,073,490	5,065,126	5,056,794	5,049,357	5,046,066	57,266,743	$ 154,947	$ 57,111,796
3.		Recoverable Costs Allocated to Energy	4,096,971	4,092,725	4,090,312	4,392,829	5,071,172	5,070,665	5,070,302	5,060,625	5,052,292	5,043,990	5,036,587	5,033,326	57,111,796		
4.		Recoverable Costs Allocated to Demand	13,084	13,052	13,022	12,992	12,959	12,928	12,897	12,865	12,834	12,804	12,770	12,740	154,947		
5.		Retail Energy Jurisdictional Factor	0.9805185	0.9869957	0.9878612	0.9932946	0.9786963	0.9784317	0.9795263	0.9805871	0.9872055	0.9936031	0.9943227	0.9802158			
6.		Retail Demand Jurisdictional Factor	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735			
7.		Jurisdictional Energy Recoverable Costs (C)	4,017,156	4,039,502	4,040,661	4,363,373	4,963,137	4,961,299	4,966,494	4,962,384	4,987,650	5,011,724	5,007,993	4,933,746	56,255,119		
8.		Jurisdictional Demand Recoverable Costs (D)	12,613	12,582	12,553	12,524	12,492	12,462	12,432	12,402	12,372	12,343	12,310	12,281	149,366		
9.		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$4,029,769	$4,052,084	$4,053,214	$4,375,897	$4,975,629	$4,973,761	$4,978,926	$4,974,786	$5,000,022	$5,024,067	$5,020,303	$4,946,027	$56,404,485		

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

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Flue Gas Desulfurization Integration
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	
3.	Less: Accumulated Depreciation	(3,211,293)	(3,227,086)	(3,242,879)	(3,258,672)	(3,274,465)	(3,290,258)	(3,306,051)	(3,321,844)	(3,337,637)	(3,353,430)	(3,369,223)	(3,385,016)	(3,400,809)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$5,028,365	5,012,572	4,996,779	4,980,986	4,965,193	4,949,400	4,933,607	4,917,814	4,902,021	4,886,228	4,870,435	4,854,642	4,838,849	
6.	Average Net Investment		5,020,469	5,004,676	4,988,883	4,973,090	4,957,297	4,941,504	4,925,711	4,909,918	4,894,125	4,878,332	4,862,539	4,846,746	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		36,477	36,362	36,248	36,133	36,018	35,903	35,789	35,674	35,559	35,444	35,330	35,215	$430,152
	b. Debt Component Grossed Up For Taxes (C)		12,268	12,230	12,191	12,153	12,114	12,075	12,037	11,998	11,960	11,921	11,882	11,844	144,673
8.	Investment Expenses														
	a. Depreciation (D)		15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	189,516
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		64,538	64,385	64,232	64,079	63,925	63,771	63,619	63,465	63,312	63,158	63,005	62,852	764,341
	a. Recoverable Costs Allocated to Energy		64,538	64,385	64,232	64,079	63,925	63,771	63,619	63,465	63,312	63,158	63,005	62,852	764,341
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9805185	0.9869957	0.9878612	0.9932946	0.9786963	0.9784317	0.9795263	0.9805871	0.9872055	0.9936031	0.9943227	0.9802158	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs €		63,281	63,548	63,452	63,649	62,563	62,396	62,316	62,233	62,502	62,754	62,647	61,609	752,950
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$63,281	$63,548	$63,452	$63,649	$62,563	$62,396	$62,316	$62,233	$62,502	$62,754	$62,647	$61,609	$752,950

Notes:
(A) Applicable depreciable base for Big Bend; account 312.45
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 Flue Gas Conditioning
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	
3.	Less: Accumulated Depreciation	(2,695,310)	(2,708,719)	(2,722,128)	(2,735,537)	(2,748,946)	(2,762,355)	(2,775,764)	(2,789,173)	(2,802,582)	(2,815,991)	(2,829,400)	(2,842,809)	(2,856,218)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,322,424	2,309,015	2,295,606	2,282,197	2,268,788	2,255,379	2,241,970	2,228,561	2,215,152	2,201,743	2,188,334	2,174,925	2,161,516	
6.	Average Net Investment		2,315,720	2,302,311	2,288,902	2,275,493	2,262,084	2,248,675	2,235,266	2,221,857	2,208,448	2,195,039	2,181,630	2,168,221	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		16,825	16,728	16,630	16,533	16,436	16,338	16,241	16,143	16,046	15,948	15,851	15,754	$195,473
	b. Debt Component Grossed Up For Taxes (C)		5,659	5,626	5,593	5,561	5,528	5,495	5,462	5,429	5,397	5,364	5,331	5,298	65,743
8.	Investment Expenses														
	a. Depreciation (D)		13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	160,908
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		35,893	35,763	35,632	35,503	35,373	35,242	35,112	34,981	34,852	34,721	34,591	34,461	422,124
	a. Recoverable Costs Allocated to Energy		35,893	35,763	35,632	35,503	35,373	35,242	35,112	34,981	34,852	34,721	34,591	34,461	422,124
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9805185	0.9869957	0.9878612	0.9932946	0.9786963	0.9784317	0.9795263	0.9805871	0.9872055	0.9936031	0.9943227	0.9802158	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs €		35,194	35,298	35,199	35,265	34,619	34,482	34,393	34,302	34,406	34,499	34,395	33,779	415,831
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$35,194	$35,298	$35,199	$35,265	$34,619	$34,482	$34,393	$34,302	$34,406	$34,499	$34,395	$33,779	$415,831

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,676,217) and 312.42 ($2,341,517)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are: 3.3% and 3.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

DOCKET NO. 110007-EI
ECRC 2010 FINAL TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 Continuous Emissions Monitors
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	
3.	Less: Accumulated Depreciation	(339,461)	(340,977)	(342,493)	(344,009)	(345,525)	(347,041)	(348,557)	(350,073)	(351,589)	(353,105)	(354,621)	(356,137)	(357,653)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$526,750	525,234	523,718	522,202	520,686	519,170	517,654	516,138	514,622	513,106	511,590	510,074	508,558	
6.	Average Net Investment		525,992	524,476	522,960	521,444	519,928	518,412	516,896	515,380	513,864	512,348	510,832	509,316	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		3,822	3,811	3,800	3,789	3,778	3,767	3,756	3,745	3,734	3,723	3,712	3,701	$45,138
	b. Debt Component Grossed Up For Taxes (C)		1,285	1,282	1,278	1,274	1,271	1,267	1,263	1,259	1,256	1,252	1,248	1,245	15,180
8.	Investment Expenses														
	a. Depreciation (D)		1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	18,192
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		6,623	6,609	6,594	6,579	6,565	6,550	6,535	6,520	6,506	6,491	6,476	6,462	78,510
	a. Recoverable Costs Allocated to Energy		6,623	6,609	6,594	6,579	6,565	6,550	6,535	6,520	6,506	6,491	6,476	6,462	78,510
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9805185	0.9869957	0.9878612	0.9932946	0.9786963	0.9784317	0.9795263	0.9805871	0.9872055	0.9936031	0.9943227	0.9802158	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (E)		6,494	6,523	6,514	6,535	6,425	6,409	6,401	6,393	6,423	6,449	6,439	6,334	77,339
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$6,494	$6,523	$6,514	$6,535	$6,425	$6,409	$6,401	$6,393	$6,423	$6,449	$6,439	$6,334	$77,339

Notes:
(A) Applicable depreciable base for Big Bend; account 315.44
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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ECRC 2010 FINAL TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 1 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	
3.	Less: Accumulated Depreciation	(146,560)	(147,638)	(148,716)	(149,794)	(150,872)	(151,950)	(153,028)	(154,106)	(155,184)	(156,262)	(157,340)	(158,418)	(159,496)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$351,018	349,940	348,862	347,784	346,706	345,628	344,550	343,472	342,394	341,316	340,238	339,160	338,082	
6.	Average Net Investment		350,479	349,401	348,323	347,245	346,167	345,089	344,011	342,933	341,855	340,777	339,699	338,621	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		2,546	2,539	2,531	2,523	2,515	2,507	2,499	2,492	2,484	2,476	2,468	2,460	$30,040
	b. Debt Component Grossed Up For Taxes (C)		856	854	851	849	846	843	841	838	835	833	830	827	10,103
8.	Investment Expenses														
	a. Depreciation (D)		1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	12,936
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		4,480	4,471	4,460	4,450	4,439	4,428	4,418	4,408	4,397	4,387	4,376	4,365	53,079
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		4,480	4,471	4,460	4,450	4,439	4,428	4,418	4,408	4,397	4,387	4,376	4,365	53,079
10.	Energy Jurisdictional Factor		0.9805185	0.9869957	0.9878612	0.9932946	0.9786963	0.9784317	0.9795263	0.9805871	0.9872055	0.9936031	0.9943227	0.9802158	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		4,319	4,310	4,299	4,290	4,279	4,268	4,259	4,249	4,239	4,229	4,218	4,208	51,167
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,319	$4,310	$4,299	$4,290	$4,279	$4,268	$4,259	$4,249	$4,239	$4,229	$4,218	$4,208	$51,167

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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ECRC 2010 FINAL TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 2 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	
3.	Less: Accumulated Depreciation	(241,072)	(242,845)	(244,618)	(246,391)	(248,164)	(249,937)	(251,710)	(253,483)	(255,256)	(257,029)	(258,802)	(260,575)	(262,348)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$577,329	575,556	573,783	572,010	570,237	568,464	566,691	564,918	563,145	561,372	559,599	557,826	556,053	
6.	Average Net Investment		576,443	574,670	572,897	571,124	569,351	567,578	565,805	564,032	562,259	560,486	558,713	556,940	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,188	4,175	4,162	4,150	4,137	4,124	4,111	4,098	4,085	4,072	4,059	4,047	$49,408
	b. Debt Component Grossed Up For Taxes (C)		1,409	1,404	1,400	1,396	1,391	1,387	1,383	1,378	1,374	1,370	1,365	1,361	16,618
8.	Investment Expenses														
	a. Depreciation (D)		1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	21,276
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		7,370	7,352	7,335	7,319	7,301	7,284	7,267	7,249	7,232	7,215	7,197	7,181	87,302
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		7,370	7,352	7,335	7,319	7,301	7,284	7,267	7,249	7,232	7,215	7,197	7,181	87,302
10.	Energy Jurisdictional Factor		0.9805185	0.9869957	0.9878612	0.9932946	0.9786963	0.9784317	0.9795263	0.9805871	0.9872055	0.9936031	0.9943227	0.9802158	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		7,104	7,087	7,071	7,055	7,038	7,022	7,005	6,988	6,971	6,955	6,938	6,922	84,156
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$7,104	$7,087	$7,071	$7,055	$7,038	$7,022	$7,005	$6,988	$6,971	$6,955	$6,938	$6,922	$84,156

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Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Phillips Upgrade Tank # 1 for FDEP
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	
3.	Less: Accumulated Depreciation	(22,536)	(22,679)	(22,822)	(22,965)	(23,108)	(23,251)	(23,394)	(23,537)	(23,680)	(23,823)	(23,966)	(24,109)	(24,252)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$34,741	34,598	34,455	34,312	34,169	34,026	33,883	33,740	33,597	33,454	33,311	33,168	33,025	
6.	Average Net Investment		34,670	34,527	34,384	34,241	34,098	33,955	33,812	33,669	33,526	33,383	33,240	33,097	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		252	251	250	249	248	247	246	245	244	243	242	240	$2,957
	b. Debt Component Grossed Up For Taxes (C)		85	84	84	84	83	83	83	82	82	82	81	81	994
8.	Investment Expenses														
	a. Depreciation (D)		143	143	143	143	143	143	143	143	143	143	143	143	1,716
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		480	478	477	476	474	473	472	470	469	468	466	464	5,667
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		480	478	477	476	474	473	472	470	469	468	466	464	5,667
10.	Energy Jurisdictional Factor		0.9805185	0.9869957	0.9878612	0.9932946	0.9786963	0.9784317	0.9795263	0.9805871	0.9872055	0.9936031	0.9943227	0.9802158	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		463	461	460	459	457	456	455	453	452	451	449	447	5,463
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$463	$461	$460	$459	$457	$456	$455	$453	$452	$451	$449	$447	$5,463

Notes:
(A) Applicable depreciable base for Phillips; account 342.28
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Phillips Upgrade Tank # 4 for FDEP
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	
3.	Less: Accumulated Depreciation	(36,011)	(36,237)	(36,463)	(36,689)	(36,915)	(37,141)	(37,367)	(37,593)	(37,819)	(38,045)	(38,271)	(38,497)	(38,723)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$54,461	54,235	54,009	53,783	53,557	53,331	53,105	52,879	52,653	52,427	52,201	51,975	51,749	
6.	Average Net Investment		54,348	54,122	53,896	53,670	53,444	53,218	52,992	52,766	52,540	52,314	52,088	51,862	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		395	393	392	390	388	387	385	383	382	380	378	377	$4,630
	b. Debt Component Grossed Up For Taxes (C)		133	132	132	131	131	130	129	129	128	128	127	127	1,557
8.	Investment Expenses														
	a. Depreciation (D)		226	226	226	226	226	226	226	226	226	226	226	226	2,712
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		754	751	750	747	745	743	740	738	736	734	731	730	8,899
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		754	751	750	747	745	743	740	738	736	734	731	730	8,899
10.	Energy Jurisdictional Factor		0.9805185	0.9869957	0.9878612	0.9932946	0.9786963	0.9784317	0.9795263	0.9805871	0.9872055	0.9936031	0.9943227	0.9802158	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		727	724	723	720	718	716	713	711	709	708	705	704	8,578
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$727	$724	$723	$720	$718	$716	$713	$711	$709	$708	$705	$704	$8,578

Notes:
(A) Applicable depreciable base for Phillips; account 342.28
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	
3.	Less: Accumulated Depreciation	(519,032)	(522,652)	(526,272)	(529,892)	(533,512)	(537,132)	(540,752)	(544,372)	(547,992)	(551,612)	(555,232)	(558,852)	(562,472)	
4.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$797,225	793,605	789,985	786,365	782,745	779,125	775,505	771,885	768,265	764,645	761,025	757,405	753,785	
6.	Average Net Investment		795,415	791,795	788,175	784,555	780,935	777,315	773,695	770,075	766,455	762,835	759,215	755,595	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		5,779	5,753	5,727	5,700	5,674	5,648	5,621	5,595	5,569	5,543	5,516	5,490	$67,615
	b. Debt Component Grossed Up For Taxes (C)		1,944	1,935	1,926	1,917	1,908	1,899	1,891	1,882	1,873	1,864	1,855	1,846	22,740
8.	Investment Expenses														
	a. Depreciation (D)		3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	43,440
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		11,343	11,308	11,273	11,237	11,202	11,167	11,132	11,097	11,062	11,027	10,991	10,956	133,795
	a. Recoverable Costs Allocated to Energy		11,343	11,308	11,273	11,237	11,202	11,167	11,132	11,097	11,062	11,027	10,991	10,956	133,795
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9805185	0.9869957	0.9878612	0.9932946	0.9786963	0.9784317	0.9795263	0.9805871	0.9872055	0.9936031	0.9943227	0.9802158	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (E)		11,122	11,161	11,136	11,162	10,963	10,926	10,904	10,882	10,920	10,956	10,929	10,739	131,800
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$11,122	$11,161	$11,136	$11,162	$10,963	$10,926	$10,904	$10,882	$10,920	$10,956	$10,929	$10,739	$131,800

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	
3.	Less: Accumulated Depreciation	(399,222)	(401,766)	(404,310)	(406,854)	(409,398)	(411,942)	(414,486)	(417,030)	(419,574)	(422,118)	(424,662)	(427,206)	(429,750)	
4.	Other	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$585,572	583,028	580,484	577,940	575,396	572,852	570,308	567,764	565,220	562,676	560,132	557,588	555,044	
6.	Average Net Investment		584,300	581,756	579,212	576,668	574,124	571,580	569,036	566,492	563,948	561,404	558,860	556,316	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,245	4,227	4,208	4,190	4,171	4,153	4,134	4,116	4,097	4,079	4,060	4,042	$49,722
	b. Debt Component Grossed Up For Taxes (C)		1,428	1,422	1,415	1,409	1,403	1,397	1,391	1,384	1,378	1,372	1,366	1,359	16,724
8.	Investment Expenses														
	a. Depreciation (D)		2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	30,528
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		8,217	8,193	8,167	8,143	8,118	8,094	8,069	8,044	8,019	7,995	7,970	7,945	96,974
	a. Recoverable Costs Allocated to Energy		8,217	8,193	8,167	8,143	8,118	8,094	8,069	8,044	8,019	7,995	7,970	7,945	96,974
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9805185	0.9869957	0.9878612	0.9932946	0.9786963	0.9784317	0.9795263	0.9805871	0.9872055	0.9936031	0.9943227	0.9802158	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (E)		8,057	8,086	8,068	8,088	7,945	7,919	7,904	7,888	7,916	7,944	7,925	7,788	95,528
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$8,057	$8,086	$8,068	$8,088	$7,945	$7,919	$7,904	$7,888	$7,916	$7,944	$7,925	$7,788	$95,528

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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DOCKET NO. 110007-EI
ECRC 2010 FINAL TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Section 114 Mercury Testing Platform
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	
3.	Less: Accumulated Depreciation	(26,059)	(26,260)	(26,461)	(26,662)	(26,863)	(27,064)	(27,265)	(27,466)	(27,667)	(27,868)	(28,069)	(28,270)	(28,471)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$94,678	94,477	94,276	94,075	93,874	93,673	93,472	93,271	93,070	92,869	92,668	92,467	92,266	
6.	Average Net Investment		94,578	94,377	94,176	93,975	93,774	93,573	93,372	93,171	92,970	92,769	92,568	92,367	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		687	686	684	683	681	680	678	677	675	674	673	671	$8,149
	b. Debt Component Grossed Up For Taxes (C)		231	231	230	230	229	229	228	228	227	227	226	226	2,742
8.	Investment Expenses														
	a. Depreciation (D)		201	201	201	201	201	201	201	201	201	201	201	201	2,412
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		1,119	1,118	1,115	1,114	1,111	1,110	1,107	1,106	1,103	1,102	1,100	1,098	13,303
	a. Recoverable Costs Allocated to Energy		1,119	1,118	1,115	1,114	1,111	1,110	1,107	1,106	1,103	1,102	1,100	1,098	13,303
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9805185	0.9869957	0.9878612	0.9932946	0.9786963	0.9784317	0.9795263	0.9805871	0.9872055	0.9936031	0.9943227	0.9802158	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (E)		1,097	1,103	1,101	1,107	1,087	1,086	1,084	1,085	1,089	1,095	1,094	1,076	13,104
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$1,097	$1,103	$1,101	$1,107	$1,087	$1,086	$1,084	$1,085	$1,089	$1,095	$1,094	$1,076	$13,104

Notes:
(A) Applicable depreciable base for Big Bend; account 311.40
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 FGD
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$198,186	$96,981	$20,699	($4,122)	($7,962)	$4,238	$43	$0	$112	$87,514	$160,007	$528,647	$1,084,343
	b. Clearings to Plant		0	0	(2,390)	2,560,418	(7,962)	4,238	43	0	112	0	0	0	2,554,459
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$84,024,382	$84,024,382	$84,024,382	$84,021,992	$86,582,410	$86,574,448	$86,578,686	$86,578,729	$86,578,729	$86,578,841	$86,578,841	$86,578,841	$86,578,841	
3.	Less: Accumulated Depreciation	(31,778,112)	(31,981,171)	(32,184,230)	(32,387,289)	(32,590,342)	(32,799,583)	(33,008,805)	(33,218,037)	(33,427,269)	(33,636,501)	(33,845,733)	(34,054,965)	(34,264,197)	
4.	CWIP - Non-Interest Bearing	2,246,284	2,444,470	2,541,451	2,564,540	0	0	0	0	0	0	87,514	247,521	776,168	
5.	Net Investment (Lines 2 + 3 + 4) (B)	$54,492,554	54,487,681	54,381,603	54,199,243	53,992,068	53,774,865	53,569,881	53,360,692	53,151,460	52,942,340	52,820,622	52,771,397	53,090,812	
6.	Average Net Investment		54,490,117	54,434,642	54,290,423	54,095,655	53,883,466	53,672,373	53,465,286	53,256,076	53,046,900	52,881,481	52,796,009	52,931,104	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		395,907	395,504	394,456	393,041	391,499	389,966	388,461	386,941	385,421	384,219	383,598	384,580	$4,673,593
	b. Debt Component Grossed Up For Taxes (C)		133,156	133,020	132,668	132,192	131,673	131,157	130,651	130,140	129,629	129,225	129,016	129,346	1,571,873
8.	Investment Expenses														
	a. Depreciation (D)		203,059	203,059	203,059	203,053	209,241	209,222	209,232	209,232	209,232	209,232	209,232	209,232	2,486,085
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		732,122	731,583	730,183	728,286	732,413	730,345	728,344	726,313	724,282	722,676	721,846	723,158	8,731,551
	a. Recoverable Costs Allocated to Energy		732,122	731,583	730,183	728,286	732,413	730,345	728,344	726,313	724,282	722,676	721,846	723,158	8,731,551
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9805185	0.9869957	0.9878612	0.9932946	0.9786963	0.9784317	0.9795263	0.9805871	0.9872055	0.9936031	0.9943227	0.9802158	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (E)		717,859	722,069	721,319	723,403	716,810	714,593	713,432	712,213	715,015	718,053	717,748	708,851	8,601,365
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$717,859	$722,069	$721,319	$723,403	$716,810	$714,593	$713,432	$712,213	$715,015	$718,053	$717,748	$708,851	$8,601,365

Notes:
(A) Applicable depreciable base for Big Bend; account 312.46
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.9%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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DOCKET NO. 110007-EI
ECRC 2010 FINAL TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD Optimization and Utilization
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	
3.	Less: Accumulated Depreciation	(4,531,789)	(4,573,431)	(4,615,073)	(4,656,715)	(4,698,357)	(4,739,999)	(4,781,641)	(4,823,283)	(4,864,925)	(4,906,567)	(4,948,209)	(4,989,851)	(5,031,493)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4) (B)	$17,207,948	17,166,306	17,124,664	17,083,022	17,041,380	16,999,738	16,958,096	16,916,454	16,874,812	16,833,170	16,791,528	16,749,886	16,708,244	
6.	Average Net Investment		17,187,127	17,145,485	17,103,843	17,062,201	17,020,559	16,978,917	16,937,275	16,895,633	16,853,991	16,812,349	16,770,707	16,729,065	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		124,876	124,573	124,271	123,968	123,666	123,363	123,061	122,758	122,455	122,153	121,850	121,548	$1,478,542
	b. Debt Component Grossed Up For Taxes (C)		42,000	41,898	41,796	41,694	41,593	41,491	41,389	41,287	41,186	41,084	40,982	40,880	497,280
8.	Investment Expenses														
	a. Depreciation (D)		41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	499,704
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		208,518	208,113	207,709	207,304	206,901	206,496	206,092	205,687	205,283	204,879	204,474	204,070	2,475,526
	a. Recoverable Costs Allocated to Energy		208,518	208,113	207,709	207,304	206,901	206,496	206,092	205,687	205,283	204,879	204,474	204,070	2,475,526
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9805185	0.9869957	0.9878612	0.9932946	0.9786963	0.9784317	0.9795263	0.9805871	0.9872055	0.9936031	0.9943227	0.9802158	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (E)		204,456	205,407	205,188	205,914	202,493	202,042	201,873	201,694	202,657	203,568	203,313	200,033	2,438,638
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$204,456	$205,407	$205,188	$205,914	$202,493	$202,042	$201,873	$201,694	$202,657	$203,568	$203,313	$200,033	$2,438,638

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.45 ($39,818) and 312.45 ($21,699,919)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 1.5% and 2.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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DOCKET NO. 110007-EI
ECRC 2010 FINAL TRUE-UP
EXHIBIT HTB-1, DOC. NO. 8, PAGE 12 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$799	$1,790	$59,480	$290	($3,920)	($22)	$0	$0	$58,417
	b. Clearings to Plant		0	0	0	0	799	1,790	59,480	290	(3,920)	(22)	0	0	$58,417
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	236,790	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$3,369,225	$3,369,225	$3,369,225	$3,369,225	$3,369,225	$3,370,024	$3,371,814	$3,431,294	$3,431,584	$3,427,664	$3,427,642	$3,427,642	$3,190,852	
3.	Less: Accumulated Depreciation	2,573,870	2,565,144	2,556,418	2,547,692	2,538,966	2,530,240	2,521,513	2,512,782	2,503,922	2,495,061	2,486,209	2,477,357	2,705,295	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4) (B)	$5,943,095	5,934,369	5,925,643	5,916,917	5,908,191	5,900,264	5,893,327	5,944,076	5,935,506	5,922,725	5,913,851	5,904,999	5,896,147	
6.	Average Net Investment		5,938,732	5,930,006	5,921,280	5,912,554	5,904,228	5,896,796	5,918,702	5,939,791	5,929,116	5,918,288	5,909,425	5,900,573	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		43,149	43,085	43,022	42,959	42,898	42,844	43,003	43,157	43,079	43,000	42,936	42,872	$516,004
	b. Debt Component Grossed Up For Taxes (C)		14,512	14,491	14,470	14,448	14,428	14,410	14,463	14,515	14,489	14,462	14,441	14,419	173,548
8.	Investment Expenses														
	a. Depreciation (D)		8,726	8,726	8,726	8,726	8,726	8,727	8,731	8,860	8,861	8,852	8,852	8,852	105,365
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		66,387	66,302	66,218	66,133	66,052	65,981	66,197	66,532	66,429	66,314	66,229	66,143	794,917
	a. Recoverable Costs Allocated to Energy		66,387	66,302	66,218	66,133	66,052	65,981	66,197	66,532	66,429	66,314	66,229	66,143	794,917
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9805185	0.9869957	0.9878612	0.9932946	0.9786963	0.9784317	0.9795263	0.9805871	0.9872055	0.9936031	0.9943227	0.9802158	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (E)		65,094	65,440	65,414	65,690	64,645	64,558	64,842	65,240	65,579	65,890	65,853	64,834	783,079
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$65,094	$65,440	$65,414	$65,690	$64,645	$64,558	$64,842	$65,240	$65,579	$65,890	$65,853	$64,834	$783,079

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,675,171), 312.42 ($1,075,718), and 312.43 ($439,963)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 3.3%, 3.1%, and 2.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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DOCKET NO. 110007-EI
ECRC 2010 FINAL TRUE-UP
EXHIBIT HTB-1, DOC. NO. 8, PAGE 13 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: PM Minimization and Monitoring
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$41	$15,022	$7,514	$91,872	$25,460	$27,374	$14,478	$2,996	$26,379	$80	($6,082)	$205,135
	b. Clearings to Plant		0	41	(3)	0	0	0	0	0	0	0	0	205,097	$205,135
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$8,311,742	$8,311,742	$8,311,783	$8,311,780	$8,311,780	$8,311,780	$8,311,780	$8,311,780	$8,311,780	$8,311,780	$8,311,780	$8,311,780	$8,516,877	
3.	Less: Accumulated Depreciation	(1,216,909)	(1,237,772)	(1,258,635)	(1,279,498)	(1,300,361)	(1,321,224)	(1,342,087)	(1,362,950)	(1,383,813)	(1,404,676)	(1,425,539)	(1,446,402)	(1,467,265)	
4.	CWIP - Non-Interest Bearing	0	0	(0)	15,025	22,539	114,412	139,872	167,246	181,724	184,720	211,099	211,179	(0)	
5.	Net Investment (Lines 2 + 3 + 4) (B)	$7,094,833	7,073,970	7,053,148	7,047,307	7,033,958	7,104,968	7,109,565	7,116,076	7,109,691	7,091,824	7,097,340	7,076,557	7,049,612	
6.	Average Net Investment		7,084,402	7,063,559	7,050,227	7,040,633	7,069,463	7,107,266	7,112,820	7,112,884	7,100,758	7,094,582	7,086,948	7,063,084	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		51,473	51,321	51,225	51,155	51,364	51,639	51,679	51,680	51,592	51,547	51,491	51,318	$617,484
	b. Debt Component Grossed Up For Taxes (C)		17,312	17,261	17,228	17,205	17,275	17,368	17,381	17,382	17,352	17,337	17,318	17,260	207,679
8.	Investment Expenses														
	a. Depreciation (D)		20,863	20,863	20,863	20,863	20,863	20,863	20,863	20,863	20,863	20,863	20,863	20,863	250,356
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		89,648	89,445	89,316	89,223	89,502	89,870	89,923	89,925	89,807	89,747	89,672	89,441	1,075,519
	a. Recoverable Costs Allocated to Energy		89,648	89,445	89,316	89,223	89,502	89,870	89,923	89,925	89,807	89,747	89,672	89,441	1,075,519
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9805185	0.9869957	0.9878612	0.9932946	0.9786963	0.9784317	0.9795263	0.9805871	0.9872055	0.9936031	0.9943227	0.9802158	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (E)		87,902	88,282	88,232	88,625	87,595	87,932	88,082	88,179	88,658	89,173	89,163	87,671	1,059,494
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$87,902	$88,282	$88,232	$88,625	$87,595	$87,932	$88,082	$88,179	$88,658	$89,173	$89,163	$87,671	$1,059,494

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,513,263), 312.42 ($5,153,072), 312.43 ($955,619), 315.41 ($17,504), 315.44 ($351,594), and 315.43 ($525,825)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 3.3%, 3.1%, 2.6%, 2.5%, 2.1%, and 2.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Polk NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	
3.	Less: Accumulated Depreciation	(311,706)	(316,130)	(320,554)	(324,978)	(329,402)	(333,826)	(338,250)	(342,674)	(347,098)	(351,522)	(355,946)	(360,370)	(364,794)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,249,767	1,245,343	1,240,919	1,236,495	1,232,071	1,227,647	1,223,223	1,218,799	1,214,375	1,209,951	1,205,527	1,201,103	1,196,679	
6.	Average Net Investment		1,247,555	1,243,131	1,238,707	1,234,283	1,229,859	1,225,435	1,221,011	1,216,587	1,212,163	1,207,739	1,203,315	1,198,891	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		9,064	9,032	9,000	8,968	8,936	8,904	8,871	8,839	8,807	8,775	8,743	8,711	$106,650
	b. Debt Component Grossed Up For Taxes (C)		3,049	3,038	3,027	3,016	3,005	2,995	2,984	2,973	2,962	2,951	2,941	2,930	35,871
8.	Investment Expenses														
	a. Depreciation (D)		4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	53,088
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		16,537	16,494	16,451	16,408	16,365	16,323	16,279	16,236	16,193	16,150	16,108	16,065	195,609
	a. Recoverable Costs Allocated to Energy		16,537	16,494	16,451	16,408	16,365	16,323	16,279	16,236	16,193	16,150	16,108	16,065	195,609
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9805185	0.9869957	0.9878612	0.9932946	0.9786963	0.9784317	0.9795263	0.9805871	0.9872055	0.9936031	0.9943227	0.9802158	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (E)		16,215	16,280	16,251	16,298	16,016	15,971	15,946	15,921	15,986	16,047	16,017	15,747	192,695
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$16,215	$16,280	$16,251	$16,298	$16,016	$15,971	$15,946	$15,921	$15,986	$16,047	$16,017	$15,747	$192,695

Notes:
(A) Applicable depreciable base for Polk; account 342.81
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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ECRC 2010 FINAL TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SOFA
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	
3.	Less: Accumulated Depreciation	(326,042)	(331,159)	(336,276)	(341,393)	(346,510)	(351,627)	(356,744)	(361,861)	(366,978)	(372,095)	(377,212)	(382,329)	(387,446)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,232,688	2,227,571	2,222,454	2,217,337	2,212,220	2,207,103	2,201,986	2,196,869	2,191,752	2,186,635	2,181,518	2,176,401	2,171,284	
6.	Average Net Investment		2,230,130	2,225,013	2,219,896	2,214,779	2,209,662	2,204,545	2,199,428	2,194,311	2,189,194	2,184,077	2,178,960	2,173,843	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		16,203	16,166	16,129	16,092	16,055	16,017	15,980	15,943	15,906	15,869	15,832	15,794	$191,986
	b. Debt Component Grossed Up For Taxes (C)		5,450	5,437	5,425	5,412	5,400	5,387	5,375	5,362	5,350	5,337	5,325	5,312	64,572
8.	Investment Expenses														
	a. Depreciation (D)		5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	61,404
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		26,770	26,720	26,671	26,621	26,572	26,521	26,472	26,422	26,373	26,323	26,274	26,223	317,962
	a. Recoverable Costs Allocated to Energy		26,770	26,720	26,671	26,621	26,572	26,521	26,472	26,422	26,373	26,323	26,274	26,223	317,962
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9805185	0.9869957	0.9878612	0.9932946	0.9786963	0.9784317	0.9795263	0.9805871	0.9872055	0.9936031	0.9943227	0.9802158	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (E)		26,248	26,373	26,347	26,442	26,006	25,949	25,930	25,909	26,036	26,155	26,125	25,704	313,224
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$26,248	$26,373	$26,347	$26,442	$26,006	$25,949	$25,930	$25,909	$26,036	$26,155	$26,125	$25,704	$313,224

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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DOCKET NO. 110007-EI
ECRC 2010 FINAL TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	
3.	Less: Accumulated Depreciation	(161,005)	(165,540)	(170,075)	(174,610)	(179,145)	(183,680)	(188,215)	(192,750)	(197,285)	(201,820)	(206,355)	(210,890)	(215,425)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,488,116	1,483,581	1,479,046	1,474,511	1,469,976	1,465,441	1,460,906	1,456,371	1,451,836	1,447,301	1,442,766	1,438,231	1,433,696	
6.	Average Net Investment		1,485,849	1,481,314	1,476,779	1,472,244	1,467,709	1,463,174	1,458,639	1,454,104	1,449,569	1,445,034	1,440,499	1,435,964	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		10,796	10,763	10,730	10,697	10,664	10,631	10,598	10,565	10,532	10,499	10,466	10,433	$127,374
	b. Debt Component Grossed Up For Taxes (C)		3,631	3,620	3,609	3,598	3,587	3,576	3,564	3,553	3,542	3,531	3,520	3,509	42,840
8.	Investment Expenses														
	a. Depreciation (D)		4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	54,420
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		18,962	18,918	18,874	18,830	18,786	18,742	18,697	18,653	18,609	18,565	18,521	18,477	224,634
	a. Recoverable Costs Allocated to Energy		18,962	18,918	18,874	18,830	18,786	18,742	18,697	18,653	18,609	18,565	18,521	18,477	224,634
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9805185	0.9869957	0.9878612	0.9932946	0.9786963	0.9784317	0.9795263	0.9805871	0.9872055	0.9936031	0.9943227	0.9802158	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (E)		18,593	18,672	18,645	18,704	18,386	18,338	18,314	18,291	18,371	18,446	18,416	18,111	221,287
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$18,593	$18,672	$18,645	$18,704	$18,386	$18,338	$18,314	$18,291	$18,371	$18,446	$18,416	$18,111	$221,287

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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DOCKET NO. 110007-EI
ECRC 2010 FINAL TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	$0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	
3.	Less: Accumulated Depreciation	(145,088)	(149,175)	(153,262)	(157,349)	(161,436)	(165,523)	(169,610)	(173,697)	(177,784)	(181,871)	(185,958)	(190,045)	(194,132)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,436,799	1,432,712	1,428,625	1,424,538	1,420,451	1,416,364	1,412,277	1,408,190	1,404,103	1,400,016	1,395,929	1,391,842	1,387,755	
6.	Average Net Investment		1,434,756	1,430,669	1,426,582	1,422,495	1,418,408	1,414,321	1,410,234	1,406,147	1,402,060	1,397,973	1,393,886	1,389,799	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		10,424	10,395	10,365	10,335	10,306	10,276	10,246	10,217	10,187	10,157	10,128	10,098	$123,134
	b. Debt Component Grossed Up For Taxes (C)		3,506	3,496	3,486	3,476	3,466	3,456	3,446	3,436	3,426	3,416	3,406	3,396	41,412
8.	Investment Expenses														
	a. Depreciation (D)		4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	49,044
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		18,017	17,978	17,938	17,898	17,859	17,819	17,779	17,740	17,700	17,660	17,621	17,581	213,590
	a. Recoverable Costs Allocated to Energy		18,017	17,978	17,938	17,898	17,859	17,819	17,779	17,740	17,700	17,660	17,621	17,581	213,590
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9805185	0.9869957	0.9878612	0.9932946	0.9786963	0.9784317	0.9795263	0.9805871	0.9872055	0.9936031	0.9943227	0.9802158	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (E)		17,666	17,744	17,720	17,778	17,479	17,435	17,415	17,396	17,474	17,547	17,521	17,233	210,408
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$17,666	$17,744	$17,720	$17,778	$17,479	$17,435	$17,415	$17,396	$17,474	$17,547	$17,521	$17,233	$210,408

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	
3.	Less: Accumulated Depreciation	(120,266)	(126,071)	(131,876)	(137,681)	(143,486)	(149,291)	(155,096)	(160,901)	(166,706)	(172,511)	(178,316)	(184,121)	(189,926)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,586,241	2,580,436	2,574,631	2,568,826	2,563,021	2,557,216	2,551,411	2,545,606	2,539,801	2,533,996	2,528,191	2,522,386	2,516,581	
6.	Average Net Investment		2,583,339	2,577,534	2,571,729	2,565,924	2,560,119	2,554,314	2,548,509	2,542,704	2,536,899	2,531,094	2,525,289	2,519,484	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		18,770	18,728	18,685	18,643	18,601	18,559	18,517	18,474	18,432	18,390	18,348	18,306	$222,453
	b. Debt Component Grossed Up For Taxes (C)		6,313	6,299	6,284	6,270	6,256	6,242	6,228	6,214	6,199	6,185	6,171	6,157	74,818
8.	Investment Expenses														
	a. Depreciation (D)		5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	69,660
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		30,888	30,832	30,774	30,718	30,662	30,606	30,550	30,493	30,436	30,380	30,324	30,268	366,931
	a. Recoverable Costs Allocated to Energy		30,888	30,832	30,774	30,718	30,662	30,606	30,550	30,493	30,436	30,380	30,324	30,268	366,931
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9805185	0.9869957	0.9878612	0.9932946	0.9786963	0.9784317	0.9795263	0.9805871	0.9872055	0.9936031	0.9943227	0.9802158	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (E)		30,286	30,431	30,400	30,512	30,009	29,946	29,925	29,901	30,047	30,186	30,152	29,669	361,464
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$30,286	$30,431	$30,400	$30,512	$30,009	$29,946	$29,925	$29,901	$30,047	$30,186	$30,152	$29,669	$361,464

Notes:
(A) Applicable depreciable base for Big Bend; account 312.43 ($1,995,677) and 315.43 ($710,830)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.6% and 2.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$3,190,980	$2,637,597	$2,838,638	$555,917	$259,637	$1,376,562	($193,218)	$136,407	$68,902	$67,968	$71,708	$69,068	$11,080,166
	b. Clearings to Plant		0	0	0	82,142,208	259,637	1,376,562	(193,218)	136,407	68,902	57,439	49,799	(5,075)	$83,892,661
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$65,168,809	$68,359,789	$70,997,386	$73,836,024	$82,142,208	$82,401,845	$83,778,408	$83,585,190	$83,721,596	$83,790,498	$83,847,936	$83,897,736	$83,892,661	
3.	Less: Accumulated Depreciation	0	0	0	0	0	(180,762)	(362,097)	(546,424)	(730,323)	(914,522)	(1,098,873)	(1,283,350)	(1,467,937)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	10,529	32,438	106,581	
5.	Net Investment (Lines 2 + 3 + 4)	$65,168,809	68,359,789	70,997,386	73,836,024	82,142,208	82,221,083	83,416,311	83,038,766	82,991,273	82,875,976	82,759,592	82,646,824	82,531,305	
6.	Average Net Investment		66,764,299	69,678,588	72,416,705	77,989,116	82,181,646	82,818,697	83,227,538	83,015,019	82,933,625	82,817,784	82,703,208	82,589,064	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		0	0	0	226,657	597,104	601,733	604,704	603,159	602,568	601,726	600,894	600,065	$5,038,610
	b. Debt Component Grossed Up For Taxes (C)		0	0	0	76,232	200,825	202,381	203,380	202,861	202,662	202,379	202,099	201,820	1,694,639
8.	Investment Expenses														
	a. Depreciation (D)		0	0	0	0	180,762	181,335	184,327	183,899	184,199	184,351	184,477	184,587	1,467,937
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	302,889	978,691	985,449	992,411	989,919	989,429	988,456	987,470	986,472	8,201,186
	a. Recoverable Costs Allocated to Energy		0	0	0	302,889	978,691	985,449	992,411	989,919	989,429	988,456	987,470	986,472	8,201,186
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9805185	0.9869957	0.9878612	0.9932946	0.9786963	0.9784317	0.9795263	0.9805871	0.9872055	0.9936031	0.9943227	0.9802158	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	300,858	957,841	964,195	972,093	970,702	976,770	982,133	981,864	966,955	8,073,411
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13) (F)		$0	$0	$0	$300,858	$957,841	$964,195	$972,093	$970,702	$976,770	$982,133	$981,864	$966,955	$8,073,411

Notes:
(A) Applicable depreciable base for Big Bend; account 311.41 ($22,276,550), 312.41($46,705,757), 315.41($14,063,245) and 316.41($847,109).
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 1.4%, 3.3%, 2.5% and 1.2%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Form 42-8A
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Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		($156,373)	$53,155	$24,117	$6,931	$126	$925	($22)	$679	$0	$10,529	$21,909	$74,143	$36,119
	b. Clearings to Plant		(156,373)	53,155	24,117	6,931	126	925	(22)	679	0	0	0	0	($70,462)
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$91,565,985	$91,409,611	$91,462,765	$91,486,883	$91,493,814	$91,493,940	$91,494,865	$91,494,843	$91,495,521	$91,495,521	$91,495,521	$91,495,521	$91,495,521	
3.	Less: Accumulated Depreciation	(707,624)	(903,683)	(1,099,406)	(1,295,243)	(1,491,133)	(1,687,037)	(1,882,941)	(2,078,848)	(2,274,864)	(2,470,881)	(2,666,898)	(2,862,915)	(3,058,932)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	10,529	32,438	106,581	
5.	Net Investment (Lines 2 + 3 + 4)	$90,858,361	90,505,928	90,363,359	90,191,640	90,002,681	89,806,903	89,611,924	89,415,995	89,220,657	89,024,640	88,839,152	88,665,044	88,543,170	
6.	Average Net Investment		90,682,144	90,434,644	90,277,500	90,097,160	89,904,792	89,709,413	89,513,959	89,318,326	89,122,649	88,931,896	88,752,098	88,604,107	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		658,866	657,068	655,926	654,616	653,218	651,799	650,379	648,957	647,535	646,150	644,843	643,768	$7,813,125
	b. Debt Component Grossed Up For Taxes (C)		221,597	220,992	220,608	220,167	219,697	219,220	218,742	218,264	217,786	217,320	216,881	216,519	2,627,793
8.	Investment Expenses														
	a. Depreciation (D)		196,059	195,723	195,837	195,890	195,904	195,904	195,907	196,016	196,017	196,017	196,017	196,017	2,351,308
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		1,076,522	1,073,783	1,072,371	1,070,673	1,068,819	1,066,923	1,065,028	1,063,237	1,061,338	1,059,487	1,057,741	1,056,304	12,792,226
	a. Recoverable Costs Allocated to Energy		1,076,522	1,073,783	1,072,371	1,070,673	1,068,819	1,066,923	1,065,028	1,063,237	1,061,338	1,059,487	1,057,741	1,056,304	12,792,226
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9805185	0.9869957	0.9878612	0.9932946	0.9786963	0.9784317	0.9795263	0.9805871	0.9872055	0.9936031	0.9943227	0.9802158	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (E)		1,055,550	1,059,819	1,059,354	1,063,494	1,046,049	1,043,911	1,043,223	1,042,596	1,047,759	1,052,710	1,051,736	1,035,406	12,601,607
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13) (F)		$1,055,550	$1,059,819	$1,059,354	$1,063,494	$1,046,049	$1,043,911	$1,043,223	$1,042,596	$1,047,759	$1,052,710	$1,051,736	$1,035,406	$12,601,607

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Notes:
(A) Applicable depreciable base for Big Bend; account 311.42 ($25,208,869), 312.42 ($49,413,609), 315.42 ($15,914,427) and 316.42 ($958,616).
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 1.6%, 3.1%, 2.5% and 2.0%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$16	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,239	$383,794	$386,050
	b. Clearings to Plant		16	0	0	0	0	0	0	0	0	0	0	0	16
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$78,714,867	$78,714,883	$78,714,883	$78,714,883	$78,714,883	$78,714,883	$78,714,883	$78,714,883	$78,714,883	$78,714,883	$78,714,883	$78,714,883	$78,714,883	
3.	Less: Accumulated Depreciation	(2,915,033)	(3,059,206)	(3,203,379)	(3,347,552)	(3,491,725)	(3,635,898)	(3,780,071)	(3,924,244)	(4,068,417)	(4,212,590)	(4,356,763)	(4,500,936)	(4,645,109)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	2,239	386,034	
5.	Net Investment (Lines 2 + 3 + 4)	$75,799,834	75,655,677	75,511,504	75,367,331	75,223,158	75,078,985	74,934,812	74,790,639	74,646,466	74,502,293	74,358,120	74,216,186	74,455,807	
6.	Average Net Investment		75,727,755	75,583,590	75,439,417	75,295,244	75,151,071	75,006,898	74,862,725	74,718,552	74,574,379	74,430,206	74,287,153	74,335,996	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		550,213	549,165	548,118	547,070	546,023	544,975	543,928	542,880	541,833	540,785	539,746	540,101	$6,534,837
	b. Debt Component Grossed Up For Taxes (C)		185,053	184,701	184,349	183,996	183,644	183,292	182,940	182,587	182,235	181,883	181,533	181,652	2,197,865
8.	Investment Expenses														
	a. Depreciation (D)		144,173	144,173	144,173	144,173	144,173	144,173	144,173	144,173	144,173	144,173	144,173	144,173	1,730,076
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		879,439	878,039	876,640	875,239	873,840	872,440	871,041	869,640	868,241	866,841	865,452	865,926	10,462,778
	a. Recoverable Costs Allocated to Energy		879,439	878,039	876,640	875,239	873,840	872,440	871,041	869,640	868,241	866,841	865,452	865,926	10,462,778
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9805185	0.9869957	0.9878612	0.9932946	0.9786963	0.9784317	0.9795263	0.9805871	0.9872055	0.9936031	0.9943227	0.9802158	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (E)		862,306	866,621	865,999	869,370	855,224	853,623	853,208	852,758	857,132	861,296	860,539	848,794	10,306,870
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13) (F)		$862,306	$866,621	$865,999	$869,370	$855,224	$853,623	$853,208	$852,758	$857,132	$861,296	$860,539	$848,794	$10,306,870

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Notes:
(A) Applicable depreciable base for Big Bend; account 311.43 ($21,689,422), 312.43 ($42,509,823), 315.43 ($13,690,954) and 316.43 ($824,684).
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 1.2%, 2.6%, 2.5%, and 2.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$317,772	$158,623	$643,493	$536,079	$14,603	($345)	($514)	($15)	$0	$0	$0	$0	$1,669,696
	b Clearings to Plant		317,772	158,623	643,493	536,079	14,603	(345)	(514)	(15)	0	0	0	0	1,669,696
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$61,183,337	$61,501,109	$61,659,732	$62,303,225	$62,839,304	$62,853,907	$62,853,562	$62,853,048	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	
3.	Less: Accumulated Depreciation	(3,851,689)	(3,956,947)	(4,062,841)	(4,169,052)	(4,276,550)	(4,385,120)	(4,493,719)	(4,602,318)	(4,710,916)	(4,819,514)	(4,928,112)	(5,036,710)	(5,145,308)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$57,331,648	57,544,162	57,596,891	58,134,173	58,562,754	58,468,787	58,359,843	58,250,730	58,142,117	58,033,519	57,924,921	57,816,323	57,707,725	
6.	Average Net Investment		57,437,905	57,570,527	57,865,532	58,348,464	58,515,771	58,414,315	58,305,287	58,196,424	58,087,818	57,979,220	57,870,622	57,762,024	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		417,325	418,288	420,432	423,940	425,156	424,419	423,627	422,836	422,047	421,258	420,469	419,680	$5,059,477
	b. Debt Component Grossed Up For Taxes (C)		140,359	140,683	141,404	142,584	142,993	142,745	142,479	142,213	141,947	141,682	141,417	141,151	1,701,657
8.	Investment Expenses														
	a. Depreciation (D)		105,258	105,894	106,211	107,498	108,570	108,599	108,599	108,598	108,598	108,598	108,598	108,598	1,293,619
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		662,942	664,865	668,047	674,022	676,719	675,763	674,705	673,647	672,592	671,538	670,484	669,429	8,054,753
	a. Recoverable Costs Allocated to Energy		662,942	664,865	668,047	674,022	676,719	675,763	674,705	673,647	672,592	671,538	670,484	669,429	8,054,753
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	-
10.	Energy Jurisdictional Factor		0.9805185	0.9869957	0.9878612	0.9932946	0.9786963	0.9784317	0.9795263	0.9805871	0.9872055	0.9936031	0.9943227	0.9802158	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (E)		650,027	656,219	659,938	669,502	662,302	661,188	660,891	660,570	663,987	667,242	666,677	656,185	7,934,728
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13) (F)		$650,027	$656,219	$659,938	$669,502	$662,302	$661,188	$660,891	$660,570	$663,987	$667,242	$666,677	$656,185	$7,934,728

Notes:
(A) Applicable depreciable base for Big Bend; account 311.44 ($16,857,250), 312.44 ($34,665,822), 315.44 ($10,642,027), and 316.44 ($687,934).
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 1.4%, 2.4%, 2.1%, and 1.7%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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DOCKET NO. 110007-EI
ECRC 2010 FINAL TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD System Reliability
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	
3.	Less: Accumulated Depreciation	(560,965)	(583,254)	(605,543)	(627,832)	(650,121)	(672,410)	(694,699)	(716,988)	(739,277)	(761,566)	(783,855)	(806,144)	(828,433)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$11,005,064	10,982,775	10,960,486	10,938,197	10,915,908	10,893,619	10,871,330	10,849,041	10,826,752	10,804,463	10,782,174	10,759,885	10,737,596	
6.	Average Net Investment		10,993,919	10,971,630	10,949,341	10,927,052	10,904,763	10,882,474	10,860,185	10,837,896	10,815,607	10,793,318	10,771,029	10,748,740	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		79,878	79,716	79,554	79,392	79,230	79,068	78,906	78,745	78,583	78,421	78,259	78,097	$947,849
	b. Debt Component Grossed Up For Taxes (C)		26,865	26,811	26,757	26,702	26,648	26,593	26,539	26,484	26,430	26,375	26,321	26,266	318,791
8.	Investment Expenses														
	a. Depreciation (D)		22,289	22,289	22,289	22,289	22,289	22,289	22,289	22,289	22,289	22,289	22,289	22,289	267,468
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		129,032	128,816	128,600	128,383	128,167	127,950	127,734	127,518	127,302	127,085	126,869	126,652	1,534,108
	a. Recoverable Costs Allocated to Energy		129,032	128,816	128,600	128,383	128,167	127,950	127,734	127,518	127,302	127,085	126,869	126,652	1,534,108
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9805185	0.9869957	0.9878612	0.9932946	0.9786963	0.9784317	0.9795263	0.9805871	0.9872055	0.9936031	0.9943227	0.9802158	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (E)		126,518	127,141	127,039	127,522	125,437	125,190	125,119	125,043	125,673	126,272	126,149	124,146	1,511,249
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$126,518	$127,141	$127,039	$127,522	$125,437	$125,190	$125,119	$125,043	$125,673	$126,272	$126,149	$124,146	$1,511,249

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Notes:
(A) Applicable depreciable base for Big Bend; account 312.44 ($1,456,209) and 312.45 ($10,109,820)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.4% and 2.3%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Clean Air Mercury Rule
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$1,715	$4,327	$8,297	$1,311	$0	$0	$0	$0	$0	$0	$0	$0	$15,650
	b. Clearings to Plant		1,715	4,327	8,297	1,311	0	0	0	0	0	0	0	0	$15,650
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,153,403	$1,155,118	$1,159,445	$1,167,742	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	
3.	Less: Accumulated Depreciation	(22,374)	(25,258)	(28,146)	(31,045)	(33,964)	(36,887)	(39,810)	(42,733)	(45,656)	(48,579)	(51,502)	(54,425)	(57,348)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,131,029	1,129,860	1,131,299	1,136,697	1,135,089	1,132,166	1,129,243	1,126,320	1,123,397	1,120,474	1,117,551	1,114,628	1,111,705	
6.	Average Net Investment		1,130,445	1,130,580	1,133,998	1,135,893	1,133,628	1,130,705	1,127,782	1,124,859	1,121,936	1,119,013	1,116,090	1,113,167	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		8,213	8,214	8,239	8,253	8,237	8,215	8,194	8,173	8,152	8,130	8,109	8,088	$98,217
	b. Debt Component Grossed Up For Taxes (C)		2,762	2,763	2,771	2,776	2,770	2,763	2,756	2,749	2,742	2,734	2,727	2,720	33,033
8.	Investment Expenses														
	a. Depreciation (D)		2,884	2,888	2,899	2,919	2,923	2,923	2,923	2,923	2,923	2,923	2,923	2,923	34,974
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		13,859	13,865	13,909	13,948	13,930	13,901	13,873	13,845	13,817	13,787	13,759	13,731	166,224
	a. Recoverable Costs Allocated to Energy		13,859	13,865	13,909	13,948	13,930	13,901	13,873	13,845	13,817	13,787	13,759	13,731	166,224
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9805185	0.9869957	0.9878612	0.9932946	0.9786963	0.9784317	0.9795263	0.9805871	0.9872055	0.9936031	0.9943227	0.9802158	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (E)		13,589	13,685	13,740	13,854	13,633	13,601	13,589	13,576	13,640	13,699	13,681	13,459	163,746
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$13,589	$13,685	$13,740	$13,854	$13,633	$13,601	$13,589	$13,576	$13,640	$13,699	$13,681	$13,459	$163,746

Notes:

(A) Applicable depreciable base for Big Bend and Polk; accounts 315.40 ($1,169,053). Accounts 312.41, 312.43, 312.44, and 345.81 will be applicable when in-service.
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.0%, 3.3%, 2.6%, 2.4% and 3.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

For Project: SO_2 Emissions Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Total
1.	Investments														
	a. Purchases/Transfers		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Sales/Transfers		$0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Auction Proceeds/Other		0	0	0	48,181	0	0	0	0	0	0	0	0	48,181
2.	*Working Capital Balance*														
	a. FERC 158.1 Allowance Inventory	$0	0	0	0	0	0	0	0	0	0	0	0	0	
	b. FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c. FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d. FERC 254.01 Regulatory Liabilities - Gains	(41,853)	(41,685)	(41,543)	(41,372)	(41,259)	(41,142)	(40,987)	(40,785)	(40,587)	(40,434)	(40,248)	(40,041)	(39,823)	
3.	Total Working Capital Balance	($41,853)	(41,685)	(41,543)	(41,372)	(41,259)	(41,142)	(40,987)	(40,785)	(40,587)	(40,434)	(40,248)	(40,041)	(39,823)	
4.	Average Net Working Capital Balance		($41,769)	($41,614)	($41,458)	($41,316)	($41,200)	($41,064)	($40,886)	($40,686)	($40,511)	($40,341)	($40,145)	($39,932)	
5.	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		(303)	(302)	(301)	(300)	(299)	(298)	(297)	(296)	(294)	(293)	(292)	(290)	(3,565)
	b. Debt Component Grossed Up For Taxes (B)		(102)	(102)	(101)	(101)	(101)	(100)	(100)	(99)	(99)	(99)	(98)	(98)	(1,200)
6.	Total Return Component (C)		(405)	(404)	(402)	(401)	(400)	(398)	(397)	(395)	(393)	(392)	(390)	(388)	(4,765)
7.	Expenses:														
	a. Gains		0	0	0	(48,181)	0	0	0	0	0	0	0	0	(48,181)
	b. Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. *SO_2 Allowance Expense*		*1,756*	*464*	*1,648*	*882*	*445*	*370*	*704*	*(140)*	*262*	*882*	*(154)*	357	7,476
8.	Net Expenses (D)		1,756	464	1,648	(47,299)	445	370	704	(140)	262	882	(154)	357	(40,705)
9.	Total System Recoverable Expenses (Lines 6 + 8)		1,351	60	1,246	(47,700)	45	(28)	307	(535)	(131)	490	(544)	(31)	(45,470)
	a. Recoverable Costs Allocated to Energy		*1,351*	*60*	*1,246*	*(47,700)*	*45*	*(28)*	*307*	*(535)*	*(131)*	*490*	*(544)*	*(31)*	(45,470)
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9805185	0.9869957	0.9878612	0.9932946	0.9786963	0.9784317	0.9795263	0.9805871	0.9872055	0.9936031	0.9943227	0.9802158	
11.	Demand Jurisdictional Factor		0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	0.9639735	
12.	Retail Energy-Related Recoverable Costs (D)		1,325	59	1,231	(47,380)	44	(27)	301	(525)	(129)	487	(541)	(30)	(45,185)
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Juris. Recoverable Costs (Lines 12 + 13)		$1,325	$59	$1,231	($47,380)	$44	($27)	$301	($525)	($129)	$487	($541)	($30)	($45,185)

Notes:
(A) Line 4 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(B) Line 4 x 2.9324% x 1/12.
(C) Line 6 is reported on Schedules 6A and 7A
(D) Line 8 is reported on Schedules 4A and 5A
(E) Line 9a x Line 10
(F) Line 9b x Line 11

* Totals on this schedule may not foot due to rounding.

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DOCKET NO. 110007-EI
ECRC 2010 FINAL TRUE-UP
EXHIBIT HTB-1, DOC. NO. 8, PAGE 26 OF 26

Form 42 - 9A

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount for the Period
January 2010 to December 2010

Calculation of Revenue Requirement Rate of Return
(In Dollars)

		(1)	(2)	(3)	(4)
		Jurisdictional Rate Base 2009 Test Year ($000)	Ratio %	Cost Rate %	Weighted Cost Rate %
Long Term Debt	$	1,384,999	40.29%	6.80%	2.7397%
Short Term Debt		7,905	0.23%	2.75%	0.0063%
Preferred Stock		0	0.00%	0.00%	0.0000%
Customer Deposits		99,502	2.89%	6.07%	0.1754%
Common Equity		1,632,612	47.49%	11.25%	5.3426%
Deferred ITC - Weighted Cost		8,964	0.26%	9.19%	0.0239%
Accumulated Deferred Income Taxes - Zero Cost ITCs		303,629	8.83%	0.00%	0.0000%
Total	$	3,437,611	100.00%		8.2879%

ITC split between Debt and Equity:

Long Term Debt	$	1,384,999	Long Term Debt	45.78%
Short Term Debt		7,905	Short Term Debt	0.26%
Equity - Preferred		0	Equity - Preferred	0.00%
Equity - Common		1,632,612	Equity - Common	53.96%
Total	$	3,025,516	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = .0239% * 46.04%	0.0110%
Equity = .0239% * 53.96%	0.0129%
Weighted Cost	0.0239%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	5.3426%
Deferred ITC - Weighted Cost	0.0129%
	5.3555%
Times Tax Multiplier	1.628002
Total Equity Component	8.7188%

Total Debt Cost Rate:

Long Term Debt	2.7397%
Short Term Debt	0.0063%
Customer Deposits	0.1754%
Deferred ITC - Weighted Cost	0.0110%
Total Debt Component	2.9324%

Notes:
Column (1) - From Order No. PSC-09-0571-FOF-EI
Column (2) - Column (1) / Total Column (1)
Column (3) - From Order No. PSC-09-0571-FOF-EI
Column (4) - Column (2) x Column (3)

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TAMPA ELECTRIC COMPANY
ENVIRONMENTAL COST RECOVERY CLAUSE

ACTUAL / ESTIMATED TRUE-UP AMOUNT
FOR THE PERIOD OF
JANUARY 2011 THROUGH DECEMBER 2011

FORMS 42-1E THROUGH 42-9E

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI EXHIBIT 32
PARTY TAMPA ELECTRIC COMPANY (DIRECT)
DESCRIPTION HOWARD T. BRYANT (HTB-2)
DATE 11/01/11

)))

Tampa Electric Company

Form 42 - 1E

Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual/Estimated Amount
JANUARY 2011 to DECEMBER 2011
(in Dollars)

Line	Period Amount
1. Over/(Under) Recovery for the Current Period (Form 42-2E, Line 5)	($459,020)
2. Interest Provision (Form 42-2E, Line 6)	(5,070)
3. Sum of Current Period Adjustments (Form 42-2E, Line 10)	0
4. Current Period True-Up Amount to be Refunded/(Recovered) in the Projection Period January 2012 to December 2012 (Lines 1 + 2 + 3)	($464,090)

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DOCKET NO. 110007-EI
ECRC 2011 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 1, PAGE 1 OF 1

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Form 42 - 2E

Current Period Actual / Estimated Amount
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	ECRC Revenues (net of Revenue Taxes)	$6,513,784	$5,431,604	$5,013,741	$5,428,243	$6,375,391	$7,008,986	$7,404,135	$7,409,535	$7,551,376	$6,753,810	$5,792,335	$5,732,857	$76,415,797
2.	True-Up Provision	332,260	332,260	332,260	332,260	332,260	332,260	332,260	332,260	332,260	332,260	332,260	332,262	3,987,122
3.	ECRC Revenues Applicable to Period (Lines 1 + 2)	6,846,044	5,763,864	5,346,001	5,760,503	6,707,651	7,341,246	7,736,395	7,741,795	7,883,636	7,086,070	6,124,595	6,065,119	80,402,919
4.	Jurisdictional ECRC Costs													
	a. O & M Activities (Form 42-5E, Line 9)	1,635,285	1,985,917	2,431,264	1,655,086	2,788,262	1,186,316	1,787,035	1,746,310	1,560,036	1,585,141	873,750	1,518,729	20,753,131
	b. Capital Investment Projects (Form 42-7E, Line 9)	5,000,601	4,994,088	5,015,263	4,998,322	4,998,525	4,993,023	4,993,050	4,988,833	4,999,250	5,025,970	5,033,715	5,068,168	60,108,808
	c. Total Jurisdictional ECRC Costs	6,635,886	6,980,005	7,446,527	6,653,408	7,786,787	6,179,339	6,780,085	6,735,143	6,559,286	6,611,111	5,907,465	6,586,897	80,861,939
5.	Over/Under Recovery (Line 3 - Line 4c)	210,158	(1,216,141)	(2,100,526)	(892,905)	(1,079,136)	1,161,907	956,310	1,006,652	1,324,350	474,959	217,130	(521,778)	(459,020)
6.	Interest Provision (Form 42-3E, Line 10)	275	100	(288)	(535)	(700)	(644)	(592)	(680)	(632)	(458)	(412)	(504)	(5,070)
7.	Beginning Balance True-Up & Interest Provision	3,987,122	3,865,295	2,316,994	(116,080)	(1,341,780)	(2,753,876)	(1,924,873)	(1,301,415)	(627,703)	363,755	505,996	390,454	3,987,122
	a. Deferred True-Up from January to December 2010	(2,616,808)	(2,616,808)	(2,616,808)	(2,616,808)	(2,616,808)	(2,616,808)	(2,616,808)	(2,616,808)	(2,616,808)	(2,616,808)	(2,616,808)	(2,616,808)	(2,616,808)
8.	True-Up Collected/(Refunded) (see Line 2)	(332,260)	(332,260)	(332,260)	(332,260)	(332,260)	(332,260)	(332,260)	(332,260)	(332,260)	(332,260)	(332,260)	(332,262)	(3,987,122)
9.	End of Period Total True-Up (Lines 5+6+7+7a+8)	1,248,487	(299,814)	(2,732,888)	(3,958,588)	(5,370,684)	(4,541,681)	(3,918,223)	(3,244,511)	(2,253,053)	(2,110,812)	(2,226,354)	(3,080,898)	(3,080,898)
10.	Adjustment to Period True-Up Including Interest	0	0	0	0	0	0	0	0	0	0	0	0	0
11.	End of Period Total True-Up (Lines 9 + 10)	$1,248,487	($299,814)	($2,732,888)	($3,958,588)	($5,370,684)	($4,541,681)	($3,918,223)	($3,244,511)	($2,253,053)	($2,110,812)	($2,226,354)	($3,080,898)	($3,080,898)

DOCKET NO. 110007-EI
ECRC 2011 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 2, PAGE 1 OF 1

Form 42 - 3E

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Interest Provision
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Beginning True-Up Amount (Form 42-2E, Line 7 + 7a + 10)	$1,370,314	$1,248,487	($299,814)	($2,732,888)	($3,958,588)	($5,370,684)	($4,541,681)	($3,918,223)	($3,244,511)	($2,253,053)	($2,110,812)	($2,226,354)	
2.	Ending True-Up Amount Before Interest	1,248,212	(299,914)	(2,732,600)	(3,958,053)	(5,369,984)	(4,541,037)	(3,917,631)	(3,243,831)	(2,252,421)	(2,110,354)	(2,225,942)	(3,080,394)	
3.	Total of Beginning & Ending True-Up (Lines 1 + 2)	2,618,526	948,573	(3,032,414)	(6,690,941)	(9,328,572)	(9,911,721)	(8,459,312)	(7,162,054)	(5,496,932)	(4,363,407)	(4,336,754)	(5,306,748)	
4.	Average True-Up Amount (Line 3 x 1/2)	1,309,263	474,287	(1,516,207)	(3,345,471)	(4,664,286)	(4,955,861)	(4,229,656)	(3,581,027)	(2,748,466)	(2,181,704)	(2,168,377)	(2,653,374)	
5.	Interest Rate (First Day of Reporting Business Month)	0.25%	0.25%	0.25%	0.20%	0.19%	0.16%	0.16%	0.18%	0.28%	0.28%	0.23%	0.23%	
6.	Interest Rate (First Day of Subsequent Business Month)	0.25%	0.25%	0.20%	0.19%	0.16%	0.16%	0.18%	0.28%	0.28%	0.23%	0.23%	0.23%	
7.	Total of Beginning & Ending Interest Rates (Lines 5 + 6)	0.50%	0.50%	0.45%	0.39%	0.35%	0.32%	0.34%	0.46%	0.56%	0.51%	0.46%	0.46%	
8.	Average Interest Rate (Line 7 x 1/2)	0.250%	0.250%	0.225%	0.195%	0.175%	0.160%	0.170%	0.230%	0.280%	0.255%	0.230%	0.230%	
9.	Monthly Average Interest Rate (Line 8 x 1/12)	0.021%	0.021%	0.019%	0.016%	0.015%	0.013%	0.014%	0.019%	0.023%	0.021%	0.019%	0.019%	
10.	Interest Provision for the Month (Line 4 x Line 9)	$275	$100	($288)	($535)	($700)	($644)	($592)	($680)	($632)	($458)	($412)	($504)	($5,070)

DOCKET NO. 110007-EI
ECRC 2011 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 3, PAGE 1 OF 1

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to 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				
	a. Big Bend Unit 3 Flue Gas Desulfurization Integration	$5,544,173	5,154,400	$389,773	7.6%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0.0%
	c. SO_2 Emissions Allowances	26,956	601,313	(574,357)	-95.5%
	d. Big Bend Units 1 & 2 FGD	7,629,441	$7,791,300	(161,859)	-2.1%
	e. Big Bend PM Minimization and Monitoring	279,413	$479,200	(199,787)	-41.7%
	f. Big Bend NO_x Emissions Reduction	379,930	$396,000	(16,070)	-4.1%
	g. NPDES Annual Surveillance Fees	34,500	34,500	0	0.0%
	h. Gannon Thermal Discharge Study	73,495	30,000	43,495	145.0%
	i. Polk NO_x Emissions Reduction	(20,284)	$50,000	(70,284)	-140.6%
	j. Bayside SCR Consumables	102,108	$115,200	(13,092)	-11.4%
	k. Big Bend Unit 4 SOFA	0	0	0	0.0%
	l. Big Bend Unit 1 Pre-SCR	249	0	249	N/A
	m. Big Bend Unit 2 Pre-SCR	0	0	0	0.0%
	n. Big Bend Unit 3 Pre-SCR	200	0	200	N/A
	o. Clean Water Act Section 316(b) Phase II Study	54,260	60,000	(5,740)	-9.6%
	p. Arsenic Groundwater Standard Program	119,369	170,000	(50,631)	-29.8%
	q. Big Bend 1 SCR	1,992,957	958,900	1,034,057	107.8%
	r. Big Bend 2 SCR	1,280,394	1,728,400	(448,006)	-25.9%
	s. Big Bend 3 SCR	1,856,640	1,695,400	161,240	9.5%
	t. Big Bend 4 SCR	1,441,134	758,200	682,934	90.1%
	u. Clean Air Mercury Rule	26,839	8,000	18,839	235.5%
	v. Greenhouse Gas Reduction Program	42,958	56,100	(13,142)	-23.4%
2.	Total Investment Projects - Recoverable Costs	$ 20,864,732	$ 20,086,913	$ 777,819	3.9%
3.	Recoverable Costs Allocated to Energy	20,583,107	19,792,413	790,694	4.0%
4.	Recoverable Costs Allocated to Demand	281,625	294,500	(12,875)	-4.4%

Notes:

Column (1) is the End of Period Totals on Form 42-5E.
Column (2) is the approved projected amount in accordance with FPSC Order No. PSC-10-0683-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Form 42 - 5E

O&M Activities
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total	Method of Classification Demand	Energy
1.	Description of O&M Activities															
	a. Big Bend Unit 3 Flue Gas Desulfurization Integration	$478,812	$508,795	$705,148	$556,426	$463,472	$571,584	$451,689	$406,065	$389,667	$369,663	$298,250	$342,582	$5,544,173		$5,544,173
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	c. SO_2 Emissions Allowances	1,750	328	2,030	1,191	4,640	4,413	3,322	1,878	1,853	1,886	1,848	1,817	26,956		26,956
	d. Big Bend Units 1 & 2 FGD	564,431	1,061,495	687,720	637,459	974,592	751,225	$551,822	$543,686	$500,305	$595,433	$353,750	$407,523	7,629,441		7,629,441
	e. Big Bend PM Minimization and Monitoring	12,796	39,264	26,228	27,530	27,135	27,942	$18,774	$19,469	$20,462	$20,875	$19,965	$18,972	279,413		279,413
	f. Big Bend NO_x Emissions Reduction	263	57,228	39,710	37,302	22,960	(3,881)	$7,942	$7,942	$42,688	$17,870	$67,507	$82,399	379,930		379,930
	g. NPDES Annual Surveillance Fees	34,500	0	0	0	0	0	0	0	0	0	0	0	34,500	34,500	
	h. Gannon Thermal Discharge Study	0	0	0	1,480	840	3,675	10,000	22,500	5,000	10,000	10,000	10,000	73,495	73,495	
	i. Polk NO_x Reduction	747	(36,480)	897	206	26	320	2,000	2,000	2,000	4,000	2,000	2,000	(20,284)		(20,284)
	j. Bayside SCR and Ammonia	23,456	0	0	12,121	0	13,330	0	13,300	13,300	13,300	0	13,300	102,108		102,108
	k. Big Bend Unit 4 SOFA	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	l. Big Bend Unit 1 Pre-SCR	249	0	0	0	0	0	0	0	0	0	0	0	249		249
	m. Big Bend Unit 2 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
	n. Big Bend Unit 3 Pre-SCR	200	0	0	0	0	0	0	0	0	0	0	0	200		200
	o. Clean Water Act Section 316(b) Phase II Study	0	0	960	4,800	7,560	13,440	5,000	12,500	2,500	2,500	2,500	2,500	54,260	54,260	
	p. Arsenic Groundwater Standard Program	0	19,362	5,817	0	22,191	0	27,000	10,000	10,000	15,000	5,000	5,000	119,369	119,369	
	q. Big Bend 1 SCR	176,235	125,027	148,707	116,980	447,715	(96,579)	187,206	187,634	172,513	177,310	195,511	154,700	1,992,957		1,992,957
	r. Big Bend 2 SCR	155,491	45,189	83,516	117,010	288,343	(75,002)	173,016	173,314	188,093	36,246	4,964	90,215	1,280,394		1,280,394
	s. Big Bend 3 SCR	112,727	133,826	119,310	96,464	391,580	10,033	179,907	180,980	167,103	155,303	117,240	192,166	1,856,640		1,856,640
	t. Big Bend 4 SCR	77,789	48,479	603,554	50,535	147,556	(27,175)	168,774	170,326	51,459	166,721	(205,122)	188,239	1,441,134		1,441,134
	u. Clean Air Mercury Rule	0	0	0	332	6,071	436	8,000	1,000	1,000	1,000	1,000	8,000	26,839		26,839
	v. Greenhouse Gas Reduction Program	10,009	0	17,265	7,172	2,513	0	3,000	3,000	0	0	0	0	42,958		42,958
2.	Total of O&M ActivitieS	1,649,456	2,002,512	2,440,862	1,667,007	2,807,192	1,193,761	1,797,453	1,757,615	1,567,942	1,587,106	874,412	1,519,413	20,864,732	$281,625	$20,583,107
3.	Recoverable Costs Allocated to Energy	1,614,956	1,983,150	2,434,085	1,660,727	2,776,601	1,176,646	1,755,453	1,712,615	1,550,442	1,559,606	856,912	1,501,913	20,583,107		
4.	Recoverable Costs Allocated to Demand	34,500	19,362	6,777	6,280	30,591	17,115	42,000	45,000	17,500	27,500	17,500	17,500	281,625		
5.	Retail Energy Jurisdictional Factor	0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9948436	0.9942533	0.9952677	0.9993134	0.9998909	0.9999235			
6.	Retail Demand Jurisdictional Factor	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819			
7.	Jurisdictional Energy Recoverable Costs (A)	1,601,907	1,967,185	2,424,707	1,649,010	2,758,666	1,169,758	1,746,401	1,702,773	1,543,105	1,558,535	856,819	1,501,798	20,480,664		
8.	Jurisdictional Demand Recoverable Costs (B)	33,378	18,732	6,557	6,076	29,596	16,558	40,634	43,537	16,931	26,606	16,931	16,931	272,467		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,635,285	$1,985,917	$2,431,264	$1,655,086	$2,788,262	$1,186,316	$1,787,035	$1,746,310	$1,560,036	$1,585,141	$873,750	$1,518,729	$20,753,131		

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

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Form 42 - 6E

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

Line		(1) Actual/Estimated	(2) Original Projection	(3) Variance Amount	(4) Percent
1.	Description of Investment Projects				
	a. Big Bend Unit 3 Flue Gas Desulfurization Integration	$742,259	$742,259	$0	0.0%
	b. Big Bend Units 1 & 2 Flue Gas Conditioning	403,377	403,377	0	0.0%
	c. Big Bend Unit 4 Continuous Emissions Monitors	76,381	76,381	0	0.0%
	d. Big Bend Fuel Oil Tank # 1 Upgrade	51,572	51,572	0	0.0%
	e. Big Bend Fuel Oil Tank # 2 Upgrade	84,824	84,824	0	0.0%
	f. Phillips Upgrade Tank # 1 for FDEP	5,461	5,461	0	0.0%
	g. Phillips Upgrade Tank # 4 for FDEP	8,584	8,584	0	0.0%
	h. Big Bend Unit 1 Classifier Replacement	128,734	128,734	0	0.0%
	i. Big Bend Unit 2 Classifier Replacement	93,421	93,421	0	0.0%
	j. Big Bend Section 114 Mercury Testing Platform	13,022	13,022	0	0.0%
	k. Big Bend Units 1 & 2 FGD	8,682,949	8,896,117	(213,168)	-2.4%
	l. Big Bend FGD Optimization and Utilization	2,417,303	2,417,303	0	0.0%
	m. Big Bend NO_x Emissions Reduction	781,211	791,631	(10,420)	-1.3%
	n. Big Bend PM Minimization and Monitoring	1,062,080	1,081,441	(19,361)	-1.8%
	o. Polk NO_x Emissions Reduction	189,422	189,422	0	0.0%
	p. Big Bend Unit 4 SOFA	310,809	310,809	0	0.0%
	q. Big Bend Unit 1 Pre-SCR	218,293	261,143	(42,850)	-16.4%
	r. Big Bend Unit 2 Pre-SCR	207,873	207,873	0	0.0%
	s. Big Bend Unit 3 Pre-SCR	358,814	358,814	0	0.0%
	t. Big Bend Unit 1 SCR	11,720,715	11,823,188	(102,473)	-0.9%
	u. Big Bend Unit 2 SCR	12,562,769	12,522,896	39,873	0.3%
	v. Big Bend Unit 3 SCR	10,430,446	10,323,816	106,630	1.0%
	w. Big Bend Unit 4 SCR	7,950,899	7,722,172	228,727	3.0%
	x. Big Bend FGD System Reliability	1,732,791	1,959,594	(226,803)	-11.6%
	y. Clean Air Mercury Rule	164,511	167,154	(2,643)	-1.6%
	z. SO_2 Emissions Allowances	(4,556)	(4,530)	(26)	0.6%
2.	Total Investment Projects - Recoverable Costs	$60,393,964	$60,636,478	($242,514)	-0.4%
3.	Recoverable Costs Allocated to Energy	$60,243,523	$60,486,037	($242,514)	-0.4%
4.	Recoverable Costs Allocated to Demand	$150,441	$150,441	$0	0.0%

Notes:
Column (1) is the End of Period Totals on Form 42-7E.
Column (2) is the approved projected amount in accordance with FPSC Order No. PSC-10-0683-FOF-EI.
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

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Form 42-7E

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Capital Investment Projects-Recoverable Costs

(in Dollars)

Line		Description (A)	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	a.	Big Bend Unit 3 Flue Gas Desulfurization Integration	$62,698	$62,545	$62,392	$62,238	$62,085	$61,931	$61,779	$61,625	$61,471	$61,318	$61,165	$61,012	$742,259		$742,259
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	34,331	34,201	34,070	33,940	33,810	33,680	33,550	33,419	33,290	33,159	33,029	32,898	403,377		403,377
	c.	Big Bend Unit 4 Continuous Emissions Monitors	6,447	6,431	6,416	6,402	6,387	6,372	6,358	6,343	6,328	6,314	6,299	6,284	76,381		76,381
	d.	Big Bend Fuel Oil Tank # 1 Upgrade	4,355	4,345	4,335	4,324	4,313	4,303	4,292	4,282	4,272	4,261	4,250	4,240	51,572	$ 51,572	
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	7,164	7,146	7,129	7,112	7,094	7,077	7,060	7,042	7,026	7,009	6,991	6,974	84,824	84,824	
	f.	Phillips Upgrade Tank # 1 for FDEP	463	461	460	458	457	456	454	453	452	450	449	448	5,461	5,461	
	g	Phillips Upgrade Tank # 4 for FDEP	727	726	723	721	719	716	714	712	710	707	706	703	8,584	8,584	
	h	Big Bend Unit 1 Classifier Replacement	10,922	10,886	10,851	10,816	10,780	10,745	10,710	10,675	10,640	10,605	10,570	10,534	128,734		128,734
	i	Big Bend Unit 2 Classifier Replacement	7,921	7,896	7,872	7,847	7,822	7,797	7,773	7,748	7,724	7,698	7,674	7,649	93,421		93,421
	j.	Big Bend Section 114 Mercury Testing Platform	1,096	1,094	1,092	1,090	1,088	1,086	1,084	1,082	1,080	1,079	1,076	1,075	13,022		13,022
	k.	Big Bend Units 1 & 2 FGD	723,838	722,116	722,809	724,293	724,399	722,532	722,548	723,368	724,817	723,529	722,979	725,721	8,682,949		8,682,949
	l	Big Bend FGD Optimization and Utilization	203,665	203,262	202,857	202,453	202,048	201,644	201,240	200,835	200,431	200,027	199,623	199,218	2,417,303		2,417,303
	m.	Big Bend NO_x Emissions Reduction	65,546	65,466	65,384	65,303	65,223	65,141	65,061	64,979	64,898	64,818	64,736	64,656	781,211		781,211
	n.	Big Bend PM Minimization and Monitoring	89,638	89,437	89,230	89,023	88,817	88,611	88,404	88,197	87,991	87,784	87,577	87,371	1,062,080		1,062,080
	o	Polk NO_x Emissions Reduction	16,022	15,978	15,935	15,892	15,850	15,807	15,764	15,721	15,677	15,635	15,592	15,549	189,422		189,422
	p	Big Bend Unit 4 SOFA	26,174	26,124	26,075	26,025	25,976	25,925	25,876	25,826	25,777	25,727	25,677	25,627	310,809		310,809
	q	Big Bend Unit 1 Pre-SCR	18,433	18,389	18,345	18,301	18,257	18,214	18,169	18,125	18,081	18,037	17,993	17,949	218,293		218,293
	r.	Big Bend Unit 2 Pre-SCR	17,541	17,501	17,462	17,422	17,382	17,343	17,303	17,263	17,224	17,184	17,144	17,104	207,873		207,873
	s.	Big Bend Unit 3 Pre-SCR	30,212	30,154	30,098	30,042	29,986	29,930	29,872	29,816	29,760	29,704	29,648	29,592	358,814		358,814
	t.	Big Bend Unit 1 SCR	985,104	983,452	981,692	979,901	978,444	977,009	977,044	975,233	973,424	971,614	969,804	967,994	11,720,715		11,720,715
	u.	Big Bend Unit 2 SCR	1,054,833	1,053,014	1,051,128	1,049,230	1,047,648	1,045,741	1,043,836	1,041,929	1,043,576	1,045,224	1,043,317	1,043,293	12,562,769		12,562,769
	v.	Big Bend Unit 3 SCR	866,391	867,478	870,987	872,230	874,164	872,744	871,318	869,887	868,457	867,027	865,597	864,166	10,430,446		10,430,446
	w	Big Bend Unit 4 SCR	668,375	667,320	666,266	665,211	664,156	663,102	662,047	660,993	659,939	658,884	657,830	656,776	7,950,899		7,950,899
	x.	Big Bend FGD System Reliability	126,436	126,219	128,153	130,541	131,022	131,458	133,647	139,107	147,006	158,734	171,677	208,791	1,732,791		1,732,791
	y.	Clean Air Mercury Rule	13,703	13,674	13,646	13,727	13,807	13,779	13,750	13,722	13,694	13,666	13,637	13,706	164,511		164,511
	z	SO_2 Emissions Allowances (B)	(386)	(385)	(384)	(382)	(382)	(381)	(379)	(378)	(377)	(375)	(374)	(373)	(4,556)		(4,556)
2.		Total Investment Projects - Recoverable Costs	5,041,649	5,034,930	5,035,023	5,034,160	5,031,352	5,022,762	5,019,274	5,018,004	5,023,368	5,029,819	5,034,666	5,068,957	60,393,964	$ 150,441	$ 60,243,523
3.		Recoverable Costs Allocated to Energy	5,028,940	5,022,252	5,022,376	5,021,545	5,018,769	5,010,210	5,006,754	5,005,515	5,010,908	5,017,392	5,022,270	5,056,592	60,243,523		
4.		Recoverable Costs Allocated to Demand	12,709	12,678	12,647	12,615	12,583	12,552	12,520	12,489	12,460	12,427	12,396	12,365	150,441		
5.		Retail Energy Jurisdictional Factor	0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9948436	0.9942533	0.9952677	0.9993134	0.9998909	0.9999235			
6		Retail Demand Jurisdictional Factor	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819			
7.		Jurisdictional Energy Recoverable Costs (C)	4,988,305	4,981,822	5,003,027	4,986,117	4,986,351	4,980,879	4,980,937	4,976,750	4,987,195	5,013,947	5,021,722	5,056,205	59,963,257		
8.		Jurisdictional Demand Recoverable Costs (D)	12,296	12,266	12,236	12,205	12,174	12,144	12,113	12,083	12,055	12,023	11,993	11,963	145,551		
9.		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$5,000,601	$4,994,088	$5,015,263	$4,998,322	$4,998,525	$4,993,023	$4,993,050	$4,988,833	$4,999,250	$5,025,970	$5,033,715	$5,068,168	$60,108,808		

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

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Flue Gas Desulfurization Integration
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	
3.	Less: Accumulated Depreciation	(3,400,809)	(3,416,602)	(3,432,395)	(3,448,188)	(3,463,981)	(3,479,774)	(3,495,567)	(3,511,360)	(3,527,153)	(3,542,946)	(3,558,739)	(3,574,532)	(3,590,325)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$4,838,849	4,823,056	4,807,263	4,791,470	4,775,677	4,759,884	4,744,091	4,728,298	4,712,505	4,696,712	4,680,919	4,665,126	4,649,333	
6.	Average Net Investment		4,830,953	4,815,160	4,799,367	4,783,574	4,767,781	4,751,988	4,736,195	4,720,402	4,704,609	4,688,816	4,673,023	4,657,230	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		35,100	34,985	34,871	34,756	34,641	34,526	34,412	34,297	34,182	34,067	33,953	33,838	$413,628
	b. Debt Component Grossed Up For Taxes (C)		11,805	11,767	11,728	11,689	11,651	11,612	11,574	11,535	11,496	11,458	11,419	11,381	139,115
8.	Investment Expenses														
	a. Depreciation (D)		15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	189,516
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		62,698	62,545	62,392	62,238	62,085	61,931	61,779	61,625	61,471	61,318	61,165	61,012	742,259
	a. Recoverable Costs Allocated to Energy		62,698	62,545	62,392	62,238	62,085	61,931	61,779	61,625	61,471	61,318	61,165	61,012	742,259
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9948436	0.9942533	0.9952677	0.9993134	0.9998909	0.9999235	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		62,191	62,042	62,152	61,799	61,684	61,568	61,460	61,271	61,180	61,276	61,158	61,007	738,788
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$62,191	$62,042	$62,152	$61,799	$61,684	$61,568	$61,460	$61,271	$61,180	$61,276	$61,158	$61,007	$738,788

Notes:
(A) Applicable depreciable base for Big Bend; account 312.45
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 Flue Gas Conditioning
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	
3.	Less: Accumulated Depreciation	(2,856,218)	(2,869,627)	(2,883,036)	(2,896,445)	(2,909,854)	(2,923,263)	(2,936,672)	(2,950,081)	(2,963,490)	(2,976,899)	(2,990,308)	(3,003,717)	(3,017,126)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,161,516	2,148,107	2,134,698	2,121,289	2,107,880	2,094,471	2,081,062	2,067,653	2,054,244	2,040,835	2,027,426	2,014,017	2,000,608	
6.	Average Net Investment		2,154,812	2,141,403	2,127,994	2,114,585	2,101,176	2,087,767	2,074,358	2,060,949	2,047,540	2,034,131	2,020,722	2,007,313	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		15,656	15,559	15,461	15,364	15,266	15,169	15,072	14,974	14,877	14,779	14,682	14,584	$181,443
	b. Debt Component Grossed Up For Taxes (C)		5,266	5,233	5,200	5,167	5,135	5,102	5,069	5,036	5,004	4,971	4,938	4,905	61,026
8.	Investment Expenses														
	a. Depreciation (D)		13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	160,908
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		34,331	34,201	34,070	33,940	33,810	33,680	33,550	33,419	33,290	33,159	33,029	32,898	403,377
	a. Recoverable Costs Allocated to Energy		34,331	34,201	34,070	33,940	33,810	33,680	33,550	33,419	33,290	33,159	33,029	32,898	403,377
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9948436	0.9942533	0.9952677	0.9993134	0.9998909	0.9999235	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		34,054	33,926	33,939	33,701	33,592	33,483	33,377	33,227	33,132	33,136	33,025	32,895	401,487
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$34,054	$33,926	$33,939	$33,701	$33,592	$33,483	$33,377	$33,227	$33,132	$33,136	$33,025	$32,895	$401,487

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,676,217) and 312.42 ($2,341,517)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 3.3% and 3.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 Continuous Emissions Monitors
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	
3.	Less: Accumulated Depreciation	(357,653)	(359,169)	(360,685)	(362,201)	(363,717)	(365,233)	(366,749)	(368,265)	(369,781)	(371,297)	(372,813)	(374,329)	(375,845)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$508,558	507,042	505,526	504,010	502,494	500,978	499,462	497,946	496,430	494,914	493,398	491,882	490,366	
6.	Average Net Investment		507,800	506,284	504,768	503,252	501,736	500,220	498,704	497,188	495,672	494,156	492,640	491,124	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		3,690	3,678	3,667	3,656	3,645	3,634	3,623	3,612	3,601	3,590	3,579	3,568	$43,543
	b. Debt Component Grossed Up For Taxes (C)		1,241	1,237	1,233	1,230	1,226	1,222	1,219	1,215	1,211	1,208	1,204	1,200	14,646
8.	Investment Expenses														
	a. Depreciation (D)		1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	18,192
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		6,447	6,431	6,416	6,402	6,387	6,372	6,358	6,343	6,328	6,314	6,299	6,284	76,381
	a. Recoverable Costs Allocated to Energy		6,447	6,431	6,416	6,402	6,387	6,372	6,358	6,343	6,328	6,314	6,299	6,284	76,381
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9948436	0.9942533	0.9952677	0.9993134	0.9998909	0.9999235	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		6,395	6,379	6,391	6,357	6,346	6,335	6,325	6,307	6,298	6,310	6,298	6,284	76,025
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$6,395	$6,379	$6,391	$6,357	$6,346	$6,335	$6,325	$6,307	$6,298	$6,310	$6,298	$6,284	$76,025

Notes:
(A) Applicable depreciable base for Big Bend; account 315.44
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 1 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	
3.	Less: Accumulated Depreciation	(159,496)	(160,574)	(161,652)	(162,730)	(163,808)	(164,886)	(165,964)	(167,042)	(168,120)	(169,198)	(170,276)	(171,354)	(172,432)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$338,082	337,004	335,926	334,848	333,770	332,692	331,614	330,536	329,458	328,380	327,302	326,224	325,146	
6.	Average Net Investment		337,543	336,465	335,387	334,309	333,231	332,153	331,075	329,997	328,919	327,841	326,763	325,685	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		2,452	2,445	2,437	2,429	2,421	2,413	2,405	2,398	2,390	2,382	2,374	2,366	$28,912
	b. Debt Component Grossed Up For Taxes (C)		825	822	820	817	814	812	809	806	804	801	798	796	9,724
8.	Investment Expenses														
	a. Depreciation (D)		1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	12,936
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		4,355	4,345	4,335	4,324	4,313	4,303	4,292	4,282	4,272	4,261	4,250	4,240	51,572
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		4,355	4,345	4,335	4,324	4,313	4,303	4,292	4,282	4,272	4,261	4,250	4,240	51,572
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9948436	0.9942533	0.9952677	0.9993134	0.9998909	0.9999235	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		4,213	4,204	4,194	4,183	4,173	4,163	4,152	4,143	4,133	4,122	4,112	4,102	49,894
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,213	$4,204	$4,194	$4,183	$4,173	$4,163	$4,152	$4,143	$4,133	$4,122	$4,112	$4,102	$49,894

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 2 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	
3.	Less: Accumulated Depreciation	(262,348)	(264,121)	(265,894)	(267,667)	(269,440)	(271,213)	(272,986)	(274,759)	(276,532)	(278,305)	(280,078)	(281,851)	(283,624)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$556,053	554,280	552,507	550,734	548,961	547,188	545,415	543,642	541,869	540,096	538,323	536,550	534,777	
6.	Average Net Investment		555,167	553,394	551,621	549,848	548,075	546,302	544,529	542,756	540,983	539,210	537,437	535,664	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,034	4,021	4,008	3,995	3,982	3,969	3,956	3,943	3,931	3,918	3,905	3,892	$47,554
	b. Debt Component Grossed Up For Taxes (C)		1,357	1,352	1,348	1,344	1,339	1,335	1,331	1,326	1,322	1,318	1,313	1,309	15,994
8.	Investment Expenses														
	a. Depreciation (D)		1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	21,276
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		7,164	7,146	7,129	7,112	7,094	7,077	7,060	7,042	7,026	7,009	6,991	6,974	84,824
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		7,164	7,146	7,129	7,112	7,094	7,077	7,060	7,042	7,026	7,009	6,991	6,974	84,824
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9948436	0.9942533	0.9952677	0.9993134	0.9998909	0.9999235	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		6,931	6,914	6,897	6,881	6,863	6,847	6,830	6,813	6,798	6,781	6,764	6,747	82,066
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$6,931	$6,914	$6,897	$6,881	$6,863	$6,847	$6,830	$6,813	$6,798	$6,781	$6,764	$6,747	$82,066

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Phillips Upgrade Tank # 1 for FDEP
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	
3.	Less: Accumulated Depreciation	(24,252)	(24,395)	(24,538)	(24,681)	(24,824)	(24,967)	(25,110)	(25,253)	(25,396)	(25,539)	(25,682)	(25,825)	(25,968)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$33,025	32,882	32,739	32,596	32,453	32,310	32,167	32,024	31,881	31,738	31,595	31,452	31,309	
6.	Average Net Investment		32,954	32,811	32,668	32,525	32,382	32,239	32,096	31,953	31,810	31,667	31,524	31,381	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		239	238	237	236	235	234	233	232	231	230	229	228	$2,802
	b. Debt Component Grossed Up For Taxes (C)		81	80	80	79	79	79	78	78	78	77	77	77	943
8.	Investment Expenses														
	a. Depreciation (D)		143	143	143	143	143	143	143	143	143	143	143	143	1,716
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		463	461	460	458	457	456	454	453	452	450	449	448	5,461
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		463	461	460	458	457	456	454	453	452	450	449	448	5,461
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9948436	0.9942533	0.9952677	0.9993134	0.9998909	0.9999235	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		448	446	445	443	442	441	439	438	437	435	434	433	5,281
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$448	$446	$445	$443	$442	$441	$439	$438	$437	$435	$434	$433	$5,281

Notes:
(A) Applicable depreciable base for Phillips; account 342.28
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Phillips Upgrade Tank # 4 for FDEP
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	
3.	Less: Accumulated Depreciation	(38,723)	(38,949)	(39,175)	(39,401)	(39,627)	(39,853)	(40,079)	(40,305)	(40,531)	(40,757)	(40,983)	(41,209)	(41,435)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$51,749	51,523	51,297	51,071	50,845	50,619	50,393	50,167	49,941	49,715	49,489	49,263	49,037	
6.	Average Net Investment		51,636	51,410	51,184	50,958	50,732	50,506	50,280	50,054	49,828	49,602	49,376	49,150	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		375	374	372	370	369	367	365	364	362	360	359	357	$4,394
	b. Debt Component Grossed Up For Taxes (C)		126	126	125	125	124	123	123	122	122	121	121	120	1,478
8.	Investment Expenses														
	a. Depreciation (D)		226	226	226	226	226	226	226	226	226	226	226	226	2,712
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		727	726	723	721	719	716	714	712	710	707	706	703	8,584
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		727	726	723	721	719	716	714	712	710	707	706	703	8,584
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9948436	0.9942533	0.9952677	0.9993134	0.9998909	0.9999235	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		703	702	699	698	696	693	691	689	687	684	683	680	8,305
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$703	$702	$699	$698	$696	$693	$691	$689	$687	$684	$683	$680	$8,305

Notes:
(A) Applicable depreciable base for Phillips; account 342.28
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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ECRC 2011 ACTUAL/ESTIMATED TRUE-UP
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Form 42-8E

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	
3.	Less: Accumulated Depreciation	(562,472)	(566,092)	(569,712)	(573,332)	(576,952)	(580,572)	(584,192)	(587,812)	(591,432)	(595,052)	(598,672)	(602,292)	(605,912)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$753,785	750,165	746,545	742,925	739,305	735,685	732,065	728,445	724,825	721,205	717,585	713,965	710,345	
6.	Average Net Investment		751,975	748,355	744,735	741,115	737,495	733,875	730,255	726,635	723,015	719,395	715,775	712,155	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		5,464	5,437	5,411	5,385	5,358	5,332	5,306	5,279	5,253	5,227	5,201	5,174	$63,827
	b. Debt Component Grossed Up For Taxes (C)		1,838	1,829	1,820	1,811	1,802	1,793	1,784	1,776	1,767	1,758	1,749	1,740	21,467
8.	Investment Expenses														
	a. Depreciation (D)		3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	43,440
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		10,922	10,886	10,851	10,816	10,780	10,745	10,710	10,675	10,640	10,605	10,570	10,534	128,734
	a. Recoverable Costs Allocated to Energy		10,922	10,886	10,851	10,816	10,780	10,745	10,710	10,675	10,640	10,605	10,570	10,534	128,734
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9948436	0.9942533	0.9952677	0.9993134	0.9998909	0.9999235	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		10,834	10,798	10,809	10,740	10,710	10,682	10,655	10,614	10,590	10,598	10,569	10,533	128,132
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$10,834	$10,798	$10,809	$10,740	$10,710	$10,682	$10,655	$10,614	$10,590	$10,598	$10,569	$10,533	$128,132

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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ECRC 2011 ACTUAL/ESTIMATED TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	
3.	Less: Accumulated Depreciation	(429,750)	(432,294)	(434,838)	(437,382)	(439,926)	(442,470)	(445,014)	(447,558)	(450,102)	(452,646)	(455,190)	(457,734)	(460,278)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$555,044	552,500	549,956	547,412	544,868	542,324	539,780	537,236	534,692	532,148	529,604	527,060	524,516	
6.	Average Net Investment		553,772	551,228	548,684	546,140	543,596	541,052	538,508	535,964	533,420	530,876	528,332	525,788	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		4,024	4,005	3,987	3,968	3,950	3,931	3,913	3,894	3,876	3,857	3,839	3,820	$47,064
	b. Debt Component Grossed Up For Taxes (C)		1,353	1,347	1,341	1,335	1,328	1,322	1,316	1,310	1,304	1,297	1,291	1,285	15,829
8.	Investment Expenses														
	a. Depreciation (D)		2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	30,528
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		7,921	7,896	7,872	7,847	7,822	7,797	7,773	7,748	7,724	7,698	7,674	7,649	93,421
	a. Recoverable Costs Allocated to Energy		7,921	7,896	7,872	7,847	7,822	7,797	7,773	7,748	7,724	7,698	7,674	7,649	93,421
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9948436	0.9942533	0.9952677	0.9993134	0.9998909	0.9999235	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		7,857	7,832	7,842	7,792	7,771	7,751	7,733	7,703	7,687	7,693	7,673	7,648	92,982
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$7,857	$7,832	$7,842	$7,792	$7,771	$7,751	$7,733	$7,703	$7,687	$7,693	$7,673	$7,648	$92,982

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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ECRC 2011 ACTUAL/ESTIMATED TRUE-UP
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Section 114 Mercury Testing Platform
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	
3.	Less: Accumulated Depreciation	(28,471)	(28,672)	(28,873)	(29,074)	(29,275)	(29,476)	(29,677)	(29,878)	(30,079)	(30,280)	(30,481)	(30,682)	(30,883)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$92,266	92,065	91,864	91,663	91,462	91,261	91,060	90,859	90,658	90,457	90,256	90,055	89,854	
6.	Average Net Investment		92,166	91,965	91,764	91,563	91,362	91,161	90,960	90,759	90,558	90,357	90,156	89,955	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		670	668	667	665	664	662	661	659	658	657	655	654	$7,940
	b. Debt Component Grossed Up For Taxes (C)		225	225	224	224	223	223	222	222	221	221	220	220	2,670
8.	Investment Expenses														
	a. Depreciation (D)		201	201	201	201	201	201	201	201	201	201	201	201	2,412
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		1,096	1,094	1,092	1,090	1,088	1,086	1,084	1,082	1,080	1,079	1,076	1,075	13,022
	a. Recoverable Costs Allocated to Energy		1,096	1,094	1,092	1,090	1,088	1,086	1,084	1,082	1,080	1,079	1,076	1,075	13,022
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9948436	0.9942533	0.9952677	0.9993134	0.9998909	0.9999235	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		1,087	1,085	1,088	1,082	1,081	1,080	1,078	1,076	1,075	1,078	1,076	1,075	12,961
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$1,087	$1,085	$1,088	$1,082	$1,081	$1,080	$1,078	$1,076	$1,075	$1,078	$1,076	$1,075	$12,961

Notes:
(A) Applicable depreciable base for Big Bend; account 311.40
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 FGD
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$29,866	$34,024	$527,165	$197,000	$27,737	$7,659	$416,396	$27,185	$57,357	$78,507	$206,555	$784,647	$2,394,098
	b. Clearings to Plant		0	0	0	434,699	1,173	0	294,195	1,283,845	54,399	60,807	5,265	164,430	2,298,813
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$86,578,841	$86,578,841	$86,578,841	$86,578,841	$87,013,540	$87,014,713	$87,014,713	$87,308,908	$88,592,753	$88,647,152	$88,707,959	$88,713,224	$88,877,654	
3.	Less: Accumulated Depreciation	(34,264,197)	(34,473,429)	(34,682,661)	(34,891,893)	(35,101,125)	(35,311,408)	(35,521,694)	(35,731,980)	(35,942,977)	(36,157,076)	(36,371,307)	(36,585,685)	(36,800,075)	
4.	CWIP - Non-Interest Bearing	776,168	806,034	840,058	1,367,223	1,129,524	1,156,088	1,163,747	1,285,948	29,288	32,246	49,946	251,236	871,453	
5.	Net Investment (Lines 2 + 3 + 4)	$53,090,812	52,911,446	52,736,237	53,054,170	53,041,938	52,859,392	52,656,765	52,862,875	52,679,063	52,522,321	52,386,597	52,378,774	52,949,031	
6.	Average Net Investment		53,001,129	52,823,842	52,895,204	53,048,054	52,950,665	52,758,079	52,759,820	52,770,969	52,600,692	52,454,459	52,382,686	52,663,903	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		385,089	383,800	384,319	385,429	384,722	383,323	383,335	383,416	382,179	381,117	380,595	382,638	$4,599,962
	b. Debt Component Grossed Up For Taxes (C)		129,517	129,084	129,258	129,632	129,394	128,923	128,927	128,955	128,539	128,181	128,006	128,693	1,547,109
8.	Investment Expenses														
	a. Depreciation (D)		209,232	209,232	209,232	209,232	210,283	210,286	210,286	210,997	214,099	214,231	214,378	214,390	2,535,878
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		723,838	722,116	722,809	724,293	724,399	722,532	722,548	723,368	724,817	723,529	722,979	725,721	8,682,949
	a. Recoverable Costs Allocated to Energy		723,838	722,116	722,809	724,293	724,399	722,532	722,548	723,368	724,817	723,529	722,979	725,721	8,682,949
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9948436	0.9942533	0.9952677	0.9993134	0.9998909	0.9999235	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		717,989	716,303	720,024	719,183	719,720	718,302	718,822	719,211	721,387	723,032	722,900	725,665	8,642,538
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$717,989	$716,303	$720,024	$719,183	$719,720	$718,302	$718,822	$719,211	$721,387	$723,032	$722,900	$725,665	$8,642,538

Notes:
(A) Applicable depreciable base for Big Bend; account 312.46
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 2.9%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD Optimization and Utilization
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	
3.	Less: Accumulated Depreciation	(5,031,493)	(5,073,135)	(5,114,777)	(5,156,419)	(5,198,061)	(5,239,703)	(5,281,345)	(5,322,987)	(5,364,629)	(5,406,271)	(5,447,913)	(5,489,555)	(5,531,197)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$16,708,244	16,666,602	16,624,960	16,583,318	16,541,676	16,500,034	16,458,392	16,416,750	16,375,108	16,333,466	16,291,824	16,250,182	16,208,540	
6.	Average Net Investment		16,687,423	16,645,781	16,604,139	16,562,497	16,520,855	16,479,213	16,437,571	16,395,929	16,354,287	16,312,645	16,271,003	16,229,361	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		121,245	120,943	120,640	120,338	120,035	119,732	119,430	119,127	118,825	118,522	118,220	117,917	$1,434,974
	b. Debt Component Grossed Up For Taxes (C)		40,778	40,677	40,575	40,473	40,371	40,270	40,168	40,066	39,964	39,863	39,761	39,659	482,625
8.	Investment Expenses														
	a. Depreciation (D)		41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	499,704
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		203,665	203,262	202,857	202,453	202,048	201,644	201,240	200,835	200,431	200,027	199,623	199,218	2,417,303
	a. Recoverable Costs Allocated to Energy		203,665	203,262	202,857	202,453	202,048	201,644	201,240	200,835	200,431	200,027	199,623	199,218	2,417,303
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9948436	0.9942533	0.9952677	0.9993134	0.9998909	0.9999235	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		202,019	201,626	202,075	201,025	200,743	200,464	200,202	199,681	199,483	199,890	199,601	199,203	2,406,012
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$202,019	$201,626	$202,075	$201,025	$200,743	$200,464	$200,202	$199,681	$199,483	$199,890	$199,601	$199,203	$2,406,012

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.45 ($39,818) and 312.45 ($21,699,919)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 1.5% and 2.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Actual November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	$0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	
3.	Less: Accumulated Depreciation	2,705,295	2,696,956	2,688,617	2,680,278	2,671,939	2,663,600	2,655,261	2,646,922	2,638,583	2,630,244	2,621,905	2,613,566	2,605,227	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$5,896,147	5,887,808	5,879,469	5,871,130	5,862,791	5,854,452	5,846,113	5,837,774	5,829,435	5,821,096	5,812,757	5,804,418	5,796,079	
6.	Average Net Investment		5,891,978	5,883,639	5,875,300	5,866,961	5,858,622	5,850,283	5,841,944	5,833,605	5,825,266	5,816,927	5,808,588	5,800,249	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		42,809	42,749	42,688	42,627	42,567	42,506	42,446	42,385	42,324	42,264	42,203	42,143	$509,711
	b. Debt Component Grossed Up For Taxes (C)		14,398	14,378	14,357	14,337	14,317	14,296	14,276	14,255	14,235	14,215	14,194	14,174	171,432
8.	Investment Expenses														
	a. Depreciation (D)		8,339	8,339	8,339	8,339	8,339	8,339	8,339	8,339	8,339	8,339	8,339	8,339	100,068
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		65,546	65,466	65,384	65,303	65,223	65,141	65,061	64,979	64,898	64,818	64,736	64,656	781,211
	a. Recoverable Costs Allocated to Energy		65,546	65,466	65,384	65,303	65,223	65,141	65,061	64,979	64,898	64,818	64,736	64,656	781,211
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9948436	0.9942533	0.9952677	0.9993134	0.9998909	0.9999235	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		65,016	64,939	65,132	64,842	64,802	64,760	64,726	64,606	64,591	64,773	64,729	64,651	777,567
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$65,016	$64,939	$65,132	$64,842	$64,802	$64,760	$64,726	$64,606	$64,591	$64,773	$64,729	$64,651	$777,567

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,675,171), 312.42 ($1,075,718), and 312.43 ($439,963)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 3.3%, 3.1%, and 2.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: PM Minimization and Monitoring
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$824	($79)	$0	$0	$143	$0	$0	$0	$0	$0	$0	$0	$888
	b. Clearings to Plant		824	(79)	0	0	143	0	0	0	0	0	0	0	$888
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$8,516,877	$8,517,701	$8,517,622	$8,517,622	$8,517,622	$8,517,765	$8,517,765	$8,517,765	$8,517,765	$8,517,765	$8,517,765	$8,517,765	$8,517,765	
3.	Less: Accumulated Depreciation	(1,467,265)	(1,488,555)	(1,509,847)	(1,531,139)	(1,552,431)	(1,573,723)	(1,595,015)	(1,616,307)	(1,637,599)	(1,658,891)	(1,680,183)	(1,701,475)	(1,722,767)	
4.	CWIP - Non-interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$7,049,612	7,029,146	7,007,775	6,986,483	6,965,191	6,944,042	6,922,750	6,901,458	6,880,166	6,858,874	6,837,582	6,816,290	6,794,998	
6.	Average Net Investment		7,039,379	7,018,461	6,997,129	6,975,837	6,954,617	6,933,396	6,912,104	6,890,812	6,869,520	6,848,228	6,826,936	6,805,644	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		51,146	50,994	50,839	50,684	50,530	50,376	50,221	50,066	49,912	49,757	49,602	49,448	$603,575
	b. Debt Component Grossed Up For Taxes (C)		17,202	17,151	17,099	17,047	16,995	16,943	16,891	16,839	16,787	16,735	16,683	16,631	203,003
8.	Investment Expenses														
	a. Depreciation (D)		21,290	21,292	21,292	21,292	21,292	21,292	21,292	21,292	21,292	21,292	21,292	21,292	255,502
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		89,638	89,437	89,230	89,023	88,817	88,611	88,404	88,197	87,991	87,784	87,577	87,371	1,062,080
	a. Recoverable Costs Allocated to Energy		89,638	89,437	89,230	89,023	88,817	88,611	88,404	88,197	87,991	87,784	87,577	87,371	1,062,080
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9948436	0.9942533	0.9952677	0.9993134	0.9998909	0.9999235	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		88,914	88,717	88,886	88,395	88,243	88,092	87,948	87,690	87,575	87,724	87,567	87,364	1,057,115
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$88,914	$88,717	$88,886	$88,395	$88,243	$88,092	$87,948	$87,690	$87,575	$87,724	$87,567	$87,364	$1,057,115

Notes:

(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,513,263), 312.42 ($5,153,072), 312.43 ($955,619), 315.41 ($17,504), 315.44 ($351,594), and 315.43 ($526,713)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 3.3%, 3.1%, 2.6%, 2.5%, 2.1%, and 2.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Polk NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	
3.	Less: Accumulated Depreciation	(364,794)	(369,218)	(373,642)	(378,066)	(382,490)	(386,914)	(391,338)	(395,762)	(400,186)	(404,610)	(409,034)	(413,458)	(417,882)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,196,679	1,192,255	1,187,831	1,183,407	1,178,983	1,174,559	1,170,135	1,165,711	1,161,287	1,156,863	1,152,439	1,148,015	1,143,591	
6.	Average Net Investment		1,194,467	1,190,043	1,185,619	1,181,195	1,176,771	1,172,347	1,167,923	1,163,499	1,159,075	1,154,651	1,150,227	1,145,803	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		8,679	8,646	8,614	8,582	8,550	8,518	8,486	8,454	8,421	8,389	8,357	8,325	$102,021
	b. Debt Component Grossed Up For Taxes (C)		2,919	2,908	2,897	2,886	2,876	2,865	2,854	2,843	2,832	2,822	2,811	2,800	34,313
8.	Investment Expenses														
	a. Depreciation (D)		4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	53,088
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		16,022	15,978	15,935	15,892	15,850	15,807	15,764	15,721	15,677	15,635	15,592	15,549	189,422
	a. Recoverable Costs Allocated to Energy		16,022	15,978	15,935	15,892	15,850	15,807	15,764	15,721	15,677	15,635	15,592	15,549	189,422
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9948436	0.9942533	0.9952677	0.9993134	0.9998909	0.9999235	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		15,893	15,849	15,874	15,780	15,748	15,714	15,683	15,631	15,603	15,624	15,590	15,548	188,537
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$15,893	$15,849	$15,874	$15,780	$15,748	$15,714	$15,683	$15,631	$15,603	$15,624	$15,590	$15,548	$188,537

Notes:
(A) Applicable depreciable base for Polk; account 342.81
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SOFA
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	
3.	Less: Accumulated Depreciation	(387,446)	(392,563)	(397,680)	(402,797)	(407,914)	(413,031)	(418,148)	(423,265)	(428,382)	(433,499)	(438,616)	(443,733)	(448,850)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,171,284	2,166,167	2,161,050	2,155,933	2,150,816	2,145,699	2,140,582	2,135,465	2,130,348	2,125,231	2,120,114	2,114,997	2,109,880	
6.	Average Net Investment		2,168,726	2,163,609	2,158,492	2,153,375	2,148,258	2,143,141	2,138,024	2,132,907	2,127,790	2,122,673	2,117,556	2,112,439	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		15,757	15,720	15,683	15,646	15,609	15,571	15,534	15,497	15,460	15,423	15,385	15,348	$186,633
	b. Debt Component Grossed Up For Taxes (C)		5,300	5,287	5,275	5,262	5,250	5,237	5,225	5,212	5,200	5,187	5,175	5,162	62,772
8.	Investment Expenses														
	a. Depreciation (D)		5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	61,404
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		26,174	26,124	26,075	26,025	25,976	25,925	25,876	25,826	25,777	25,727	25,677	25,627	310,809
	a. Recoverable Costs Allocated to Energy		26,174	26,124	26,075	26,025	25,976	25,925	25,876	25,826	25,777	25,727	25,677	25,627	310,809
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9948436	0.9942533	0.9952677	0.9993134	0.9998909	0.9999235	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		25,963	25,914	25,975	25,841	25,808	25,773	25,743	25,678	25,655	25,709	25,674	25,625	309,358
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$25,963	$25,914	$25,975	$25,841	$25,808	$25,773	$25,743	$25,678	$25,655	$25,709	$25,674	$25,625	$309,358

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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DOCKET NO. 110007-EI
ECRC 2011 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 8, PAGE 16 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Form 42-8E
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Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	
3.	Less: Accumulated Depreciation	(215,425)	(219,960)	(224,495)	(229,030)	(233,565)	(238,100)	(242,635)	(247,170)	(251,705)	(256,240)	(260,775)	(265,310)	(269,845)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,433,696	1,429,161	1,424,626	1,420,091	1,415,556	1,411,021	1,406,486	1,401,951	1,397,416	1,392,881	1,388,346	1,383,811	1,379,276	
6.	Average Net Investment		1,431,429	1,426,894	1,422,359	1,417,824	1,413,289	1,408,754	1,404,219	1,399,684	1,395,149	1,390,614	1,386,079	1,381,544	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		10,400	10,367	10,334	10,301	10,268	10,236	10,203	10,170	10,137	10,104	10,071	10,038	$122,629
	b. Debt Component Grossed Up For Taxes (C)		3,498	3,487	3,476	3,465	3,454	3,443	3,431	3,420	3,409	3,398	3,387	3,376	41,244
8.	Investment Expenses														
	a. Depreciation (D)		4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	54,420
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		18,433	18,389	18,345	18,301	18,257	18,214	18,169	18,125	18,081	18,037	17,993	17,949	218,293
	a. Recoverable Costs Allocated to Energy		18,433	18,389	18,345	18,301	18,257	18,214	18,169	18,125	18,081	18,037	17,993	17,949	218,293
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9948436	0.9942533	0.9952677	0.9993134	0.9998909	0.9999235	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		18,284	18,241	18,274	18,172	18,139	18,107	18,075	18,021	17,995	18,025	17,991	17,948	217,272
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$18,284	$18,241	$18,274	$18,172	$18,139	$18,107	$18,075	$18,021	$17,995	$18,025	$17,991	$17,948	$217,272

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	$0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	
3.	Less: Accumulated Depreciation	(194,132)	(198,219)	(202,306)	(206,393)	(210,480)	(214,567)	(218,654)	(222,741)	(226,828)	(230,915)	(235,002)	(239,089)	(243,176)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,387,755	1,383,668	1,379,581	1,375,494	1,371,407	1,367,320	1,363,233	1,359,146	1,355,059	1,350,972	1,346,885	1,342,798	1,338,711	
6.	Average Net Investment		1,385,712	1,381,625	1,377,538	1,373,451	1,369,364	1,365,277	1,361,190	1,357,103	1,353,016	1,348,929	1,344,842	1,340,755	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		10,068	10,038	10,009	9,979	9,949	9,920	9,890	9,860	9,831	9,801	9,771	9,741	$118,857
	b. Debt Component Grossed Up For Taxes (C)		3,386	3,376	3,366	3,356	3,346	3,336	3,326	3,316	3,306	3,296	3,286	3,276	39,972
8.	Investment Expenses														
	a. Depreciation (D)		4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	49,044
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		17,541	17,501	17,462	17,422	17,382	17,343	17,303	17,263	17,224	17,184	17,144	17,104	207,873
	a. Recoverable Costs Allocated to Energy		17,541	17,501	17,462	17,422	17,382	17,343	17,303	17,263	17,224	17,184	17,144	17,104	207,873
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9948436	0.9942533	0.9952677	0.9993134	0.9998909	0.9999235	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		17,399	17,360	17,395	17,299	17,270	17,241	17,214	17,164	17,142	17,172	17,142	17,103	206,901
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$17,399	$17,360	$17,395	$17,299	$17,270	$17,241	$17,214	$17,164	$17,142	$17,172	$17,142	$17,103	$206,901

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	
3.	Less: Accumulated Depreciation	(189,926)	(195,731)	(201,536)	(207,341)	(213,146)	(218,951)	(224,756)	(230,561)	(236,366)	(242,171)	(247,976)	(253,781)	(259,586)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,516,581	2,510,776	2,504,971	2,499,166	2,493,361	2,487,556	2,481,751	2,475,946	2,470,141	2,464,336	2,458,531	2,452,726	2,446,921	
6.	Average Net Investment		2,513,679	2,507,874	2,502,069	2,496,264	2,490,459	2,484,654	2,478,849	2,473,044	2,467,239	2,461,434	2,455,629	2,449,824	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		18,264	18,221	18,179	18,137	18,095	18,053	18,010	17,968	17,926	17,884	17,842	17,800	$216,379
	b. Debt Component Grossed Up For Taxes (C)		6,143	6,128	6,114	6,100	6,086	6,072	6,057	6,043	6,029	6,015	6,001	5,987	72,775
8.	Investment Expenses														
	a. Depreciation (D)		5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	69,660
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		30,212	30,154	30,098	30,042	29,986	29,930	29,872	29,816	29,760	29,704	29,648	29,592	358,814
	a. Recoverable Costs Allocated to Energy		30,212	30,154	30,098	30,042	29,986	29,930	29,872	29,816	29,760	29,704	29,648	29,592	358,814
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9948436	0.9942533	0.9952677	0.9993134	0.9998909	0.9999235	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		29,968	29,911	29,982	29,830	29,792	29,755	29,718	29,645	29,619	29,684	29,645	29,590	357,139
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$29,968	$29,911	$29,982	$29,830	$29,792	$29,755	$29,718	$29,645	$29,619	$29,684	$29,645	$29,590	$357,139

Notes:
(A) Applicable depreciable base for Big Bend; account 312.43 ($1,995,677) and 315.43 ($710,830)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.6% and 2.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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DOCKET NO. 110007-EI
ECRC 2011 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 8, PAGE 19 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$20,912	$4,969	$882	($793)	$12	$74,088	$0	$0	$0	$0	$0	$0	$100,070
	b. Clearings to Plant		6,059	2,301	(19)	124,210	12	74,088	0	0	0	0	0	0	$206,651
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$83,892,661	$83,898,720	$83,901,021	$83,901,002	$84,025,211	$84,025,223	$84,099,311	$84,099,312	$84,099,312	$84,099,312	$84,099,312	$84,099,312	$84,099,312	
3.	Less: Accumulated Depreciation	(1,467,937)	(1,652,512)	(1,837,101)	(2,021,694)	(2,206,287)	(2,391,222)	(2,576,157)	(2,762,570)	(2,948,983)	(3,135,396)	(3,321,809)	(3,508,222)	(3,694,635)	
4.	CWIP - Non-Interest Bearing	106,581	121,434	124,102	125,003	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$82,531,305	82,367,642	82,188,022	82,004,311	81,818,924	81,634,001	81,523,154	81,336,742	81,150,329	80,963,916	80,777,503	80,591,090	80,404,677	
6.	Average Net Investment		82,449,474	82,277,832	82,096,167	81,911,618	81,726,463	81,578,578	81,429,948	81,243,536	81,057,123	80,870,710	80,684,297	80,497,884	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		599,050	597,803	596,483	595,143	593,797	592,723	591,643	590,288	588,934	587,580	586,225	584,871	$7,104,540
	b. Debt Component Grossed Up For Taxes (C)		201,479	201,060	200,616	200,165	199,712	199,351	198,988	198,532	198,077	197,621	197,166	196,710	2,389,477
8.	Investment Expenses														
	a. Depreciation (D)		184,575	184,589	184,593	184,593	184,935	184,935	186,413	186,413	186,413	186,413	186,413	186,413	2,226,698
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		985,104	983,452	981,692	979,901	978,444	977,009	977,044	975,233	973,424	971,614	969,804	967,994	11,720,715
	a. Recoverable Costs Allocated to Energy		985,104	983,452	981,692	979,901	978,444	977,009	977,044	975,233	973,424	971,614	969,804	967,994	11,720,715
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9948436	0.9942533	0.9952677	0.9993134	0.9998909	0.9999235	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		977,144	975,535	977,910	972,988	972,124	971,289	972,006	969,629	968,817	970,947	969,698	967,920	11,666,007
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$977,144	$975,535	$977,910	$972,988	$972,124	$971,289	$972,006	$969,629	$968,817	$970,947	$969,698	$967,920	$11,666,007

Notes:
(A) Applicable depreciable base for Big Bend; account 311.41 ($25,152,322), 312.41 ($52,950,343), 315.41 ($5,040,180), and 316.41 ($956,467).
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 1.4%, 3.3%, 2.5% and 1.2%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$14,853	$2,668	$901	$0	$0	$0	$0	$0	$732,000	$0	$0	$0	$750,422
	b. Clearings to Plant		0	0	0	125,003	0	0	0	0	0	0	732,000	0	$857,003
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$91,495,521	$91,495,521	$91,495,521	$91,495,521	$91,620,524	$91,620,524	$91,620,524	$91,620,524	$91,620,524	$91,620,524	$91,620,524	$92,352,524	$92,352,524	
3.	Less: Accumulated Depreciation	(3,058,932)	(3,254,949)	(3,450,966)	(3,646,983)	(3,843,000)	(4,039,340)	(4,235,680)	(4,432,020)	(4,628,360)	(4,824,700)	(5,021,040)	(5,217,380)	(5,415,611)	
4.	CWIP - Non-Interest Bearing	106,581	121,434	124,102	125,003	(0)	(0)	(0)	(0)	(0)	732,000	732,000	(0)	(0)	
5.	Net Investment (Lines 2 + 3 + 4)	$88,543,170	88,362,006	88,168,657	87,973,541	87,777,524	87,581,184	87,384,844	87,188,504	86,992,164	87,527,824	87,331,484	87,135,144	86,936,913	
6.	Average Net Investment		88,452,588	88,265,332	88,071,099	87,875,533	87,679,354	87,483,014	87,286,674	87,090,334	87,259,994	87,429,654	87,233,314	87,036,029	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		642,667	641,306	639,895	638,474	637,049	635,622	634,196	632,769	634,002	635,235	633,808	632,375	$7,637,398
	b. Debt Component Grossed Up For Taxes (C)		216,149	215,691	215,216	214,739	214,259	213,779	213,300	212,820	213,234	213,649	213,169	212,687	2,568,692
8.	Investment Expenses														
	a. Depreciation (D)		196,017	196,017	196,017	196,017	196,340	196,340	196,340	196,340	196,340	196,340	196,340	198,231	2,356,679
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		1,054,833	1,053,014	1,051,128	1,049,230	1,047,648	1,045,741	1,043,836	1,041,929	1,043,576	1,045,224	1,043,317	1,043,293	12,562,769
	a. Recoverable Costs Allocated to Energy		1,054,833	1,053,014	1,051,128	1,049,230	1,047,648	1,045,741	1,043,836	1,041,929	1,043,576	1,045,224	1,043,317	1,043,293	12,562,769
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9948436	0.9942533	0.9952677	0.9993134	0.9998909	0.9999235	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		1,046,310	1,044,537	1,047,078	1,041,828	1,040,881	1,039,619	1,038,454	1,035,941	1,038,637	1,044,506	1,043,203	1,043,213	12,504,207
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$1,046,310	$1,044,537	$1,047,078	$1,041,828	$1,040,881	$1,039,619	$1,038,454	$1,035,941	$1,038,637	$1,044,506	$1,043,203	$1,043,213	$12,504,207

Notes:

(A) Applicable depreciable base for Big Bend; account 311.42 ($25,208,869), 312.42 ($50,270,612), 315.42 ($15,914,427), and 316.42 ($958,616).
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 1.6%, 3.1%, 2.5% and 2.0%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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DOCKET NO. 11007-EI
ECRC 2011 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 8, PAGE 21 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$333	$511,969	$499,292	$45,035	$1,120	$390	$0	$0	$0	$0	$0	$0	$1,058,139
	b. Clearings to Plant		0	0	0	1,442,663	1,120	390	0	0	0	0	0	0	1,444,173
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$78,714,882	$78,714,882	$78,714,882	$78,714,882	$80,157,544	$80,158,664	$80,159,055	$80,159,055	$80,159,055	$80,159,055	$80,159,055	$80,159,055	$80,159,055	
3.	Less: Accumulated Depreciation	(4,645,109)	(4,789,282)	(4,933,455)	(5,077,628)	(5,221,801)	(5,369,099)	(5,516,400)	(5,663,702)	(5,811,004)	(5,958,306)	(6,105,608)	(6,252,910)	(6,400,212)	
4.	CWIP - Non-Interest Bearing	386,034	386,367	898,336	1,397,628	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$74,455,807	74,311,967	74,679,763	75,034,882	74,935,743	74,789,565	74,642,655	74,495,353	74,348,051	74,200,749	74,053,447	73,906,145	73,758,843	
6.	Average Net Investment		74,383,887	74,495,865	74,857,322	74,985,312	74,862,654	74,716,110	74,569,004	74,421,702	74,274,400	74,127,098	73,979,796	73,832,494	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		540,449	541,262	543,888	544,818	543,927	542,862	541,794	540,723	539,653	538,583	537,513	536,442	$6,491,914
	b. Debt Component Grossed Up For Taxes (C)		181,769	182,043	182,926	183,239	182,939	182,581	182,222	181,862	181,502	181,142	180,782	180,422	2,183,429
8.	Investment Expenses														
	a. Depreciation (D)		144,173	144,173	144,173	144,173	147,298	147,301	147,302	147,302	147,302	147,302	147,302	147,302	1,755,103
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		866,391	867,478	870,987	872,230	874,164	872,744	871,318	869,887	868,457	867,027	865,597	864,166	10,430,446
	a. Recoverable Costs Allocated to Energy		866,391	867,478	870,987	872,230	874,164	872,744	871,318	869,887	868,457	867,027	865,597	864,166	10,430,446
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9948436	0.9942533	0.9952677	0.9993134	0.9998909	0.9999235	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		859,390	860,495	867,631	866,076	868,518	867,635	866,825	864,888	864,347	866,432	865,503	864,100	10,381,840
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$859,390	$860,495	$867,631	$866,076	$868,518	$867,635	$866,825	$864,888	$864,347	$866,432	$865,503	$864,100	$10,381,840

Notes:
(A) Applicable depreciable base for Big Bend; account 311.43 ($21,689,422), 312.43 ($43,953,995), 315.43 ($13,690,954), and 316.43 ($824,684).
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 1.2%, 2.6%, 2.5%, and 2.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	
3.	Less: Accumulated Depreciation	(5,145,308)	(5,253,906)	(5,362,504)	(5,471,102)	(5,579,700)	(5,688,298)	(5,796,896)	(5,905,494)	(6,014,092)	(6,122,690)	(6,231,288)	(6,339,886)	(6,448,484)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$57,707,725	57,599,127	57,490,529	57,381,931	57,273,333	57,164,735	57,056,137	56,947,539	56,838,941	56,730,343	56,621,745	56,513,147	56,404,549	
6.	Average Net Investment		57,653,426	57,544,828	57,436,230	57,327,632	57,219,034	57,110,436	57,001,838	56,893,240	56,784,642	56,676,044	56,567,446	56,458,848	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		418,891	418,102	417,313	416,523	415,734	414,945	414,156	413,367	412,578	411,789	411,000	410,211	$4,974,609
	b. Debt Component Grossed Up For Taxes (C)		140,886	140,620	140,355	140,090	139,824	139,559	139,293	139,028	138,763	138,497	138,232	137,967	1,673,114
8.	Investment Expenses														
	a. Depreciation (D)		108,598	108,598	108,598	108,598	108,598	108,598	108,598	108,598	108,598	108,598	108,598	108,598	1,303,176
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		668,375	667,320	666,266	665,211	664,156	663,102	662,047	660,993	659,939	658,884	657,830	656,776	7,950,899
	a. Recoverable Costs Allocated to Energy		668,375	667,320	666,266	665,211	664,156	663,102	662,047	660,993	659,939	658,884	657,830	656,776	7,950,899
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	-
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9948436	0.9942533	0.9952677	0.9993134	0.9998909	0.9999235	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		662,974	661,948	663,699	660,518	659,866	659,220	658,633	657,194	656,816	658,432	657,758	656,726	7,913,784
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$662,974	$661,948	$663,699	$660,518	$659,866	$659,220	$658,633	$657,194	$656,816	$658,432	$657,758	$656,726	$7,913,784

Notes:
(A) Applicable depreciable base for Big Bend; account 311.44 ($16,857,250) , 312.44 ($34,665,822), 315.44 ($10,642,027), and 316.44 ($687,934).
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 1.4%, 2.4%, 2.1%, and 1.7%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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DOCKET NO. 110007-EI
ECRC 2011 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 8, PAGE 23 OF 26

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD System Reliability
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$442,854	$93,805	$49,879	$84,367	$411,079	$758,158	$913,671	$1,546,574	$1,164,287	$6,525,298	$11,989,972
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	$11,566,029	
3.	Less: Accumulated Depreciation	(828,433)	(850,722)	(873,011)	(895,300)	(917,589)	(939,878)	(962,167)	(984,456)	(1,006,745)	(1,029,034)	(1,051,323)	(1,073,612)	(1,095,901)	
4.	CWIP - Non-Interest Bearing	0	0	0	442,854	536,659	586,538	670,905	1,081,984	1,840,142	2,753,813	4,300,387	5,464,674	11,989,972	
5.	Net Investment (Lines 2 + 3 + 4)	$10,737,596	10,715,307	10,693,018	11,113,582	11,185,099	11,212,689	11,274,767	11,663,557	12,399,426	13,290,808	14,815,093	15,957,091	22,460,100	
6.	Average Net Investment		10,726,451	10,704,162	10,903,300	11,149,340	11,198,894	11,243,728	11,469,162	12,031,491	12,845,117	14,052,950	15,386,092	19,208,595	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		77,935	77,773	79,220	81,007	81,367	81,693	83,331	87,417	93,328	102,104	111,790	139,563	$1,096,528
	b. Debt Component Grossed Up For Taxes (C)		26,212	26,157	26,644	27,245	27,366	27,476	28,027	29,401	31,389	34,341	37,598	46,939	368,795
8.	Investment Expenses														
	a. Depreciation (D)		22,289	22,289	22,289	22,289	22,289	22,289	22,289	22,289	22,289	22,289	22,289	22,289	267,468
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		126,436	126,219	128,153	130,541	131,022	131,458	133,647	139,107	147,006	158,734	171,677	208,791	1,732,791
	a. Recoverable Costs Allocated to Energy		126,436	126,219	128,153	130,541	131,022	131,458	133,647	139,107	147,006	158,734	171,677	208,791	1,732,791
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9948436	0.9942533	0.9952677	0.9993134	0.9998909	0.9999235	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		125,414	125,203	127,659	129,620	130,176	130,688	132,958	138,308	146,310	158,625	171,658	208,775	1,725,394
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$125,414	$125,203	$127,659	$129,620	$130,176	$130,688	$132,958	$138,308	$146,310	$158,625	$171,658	$208,775	$1,725,394

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44 ($1,456,209) and 312.45 ($10,109,820)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.4% and 2.3%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Clean Air Mercury Rule
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$22,458	$0	$0	$0	$0	$0	$0	$0	$20,000	$42,458
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	$0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	
3.	Less: Accumulated Depreciation	(57,348)	(60,271)	(63,194)	(66,117)	(69,040)	(71,963)	(74,886)	(77,809)	(80,732)	(83,655)	(86,578)	(89,501)	(92,424)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	22,458	22,458	22,458	22,458	22,458	22,458	22,458	22,458	42,458	
5.	Net Investment (Lines 2 + 3 + 4)	$1,111,705	1,108,782	1,105,859	1,102,936	1,122,471	1,119,548	1,116,625	1,113,702	1,110,779	1,107,856	1,104,933	1,102,010	1,119,087	
6.	Average Net Investment		1,110,244	1,107,321	1,104,398	1,112,704	1,121,010	1,118,087	1,115,164	1,112,241	1,109,318	1,106,395	1,103,472	1,110,549	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		8,067	8,045	8,024	8,085	8,145	8,124	8,102	8,081	8,060	8,039	8,017	8,069	$96,858
	b. Debt Component Grossed Up For Taxes (C)		2,713	2,706	2,699	2,719	2,739	2,732	2,725	2,718	2,711	2,704	2,697	2,714	32,577
8.	Investment Expenses														
	a. Depreciation (D)		2,923	2,923	2,923	2,923	2,923	2,923	2,923	2,923	2,923	2,923	2,923	2,923	35,076
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		13,703	13,674	13,646	13,727	13,807	13,779	13,750	13,722	13,694	13,666	13,637	13,706	164,511
	a. Recoverable Costs Allocated to Energy		13,703	13,674	13,646	13,727	13,807	13,779	13,750	13,722	13,694	13,666	13,637	13,706	164,511
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9948436	0.9942533	0.9952677	0.9993134	0.9998909	0.9999235	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (E)		13,592	13,564	13,593	13,630	13,718	13,698	13,679	13,643	13,629	13,657	13,636	13,705	163,744
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$13,592	$13,564	$13,593	$13,630	$13,718	$13,698	$13,679	$13,643	$13,629	$13,657	$13,636	$13,705	$163,744

Notes:
(A) Applicable depreciable base for Big Bend and Polk; accounts 315.40 ($1,169,053). Accounts 312.41, 312.43, 312.44, and 345.81 will be applicable when in-service.
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.0%, 3.3%, 2.6%, 2.4% and 3.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

For Project: SO_2 Emissions Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Total
1.	Investments														
	a. Purchases/Transfers		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Sales/Transfers		$0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Auction Proceeds/Other		0	0	0	3,604	0	0	0	0	0	0	0	0	3,604
2.	Working Capital Balance														
	a. FERC 158.1 Allowance Inventory	$0	0	0	0	0	0	0	0	0	0	0	0	0	
	b. FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c. FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d. FERC 254.01 Regulatory Liabilities - Gains	(39,823)	(39,686)	(39,577)	(39,481)	(39,348)	(39,244)	(39,126)	(38,976)	(38,826)	(38,714)	(38,591)	(38,479)	(38,349)	
3.	Total Working Capital Balance	($39,823)	(39,686)	(39,577)	(39,481)	(39,348)	(39,244)	(39,126)	(38,976)	(38,826)	(38,714)	(38,591)	(38,479)	(38,349)	
4.	Average Net Working Capital Balance		($39,754)	($39,631)	($39,529)	($39,414)	($39,296)	($39,185)	($39,051)	($38,901)	($38,770)	($38,652)	($38,535)	($38,414)	
5.	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		(289)	(288)	(287)	(286)	(286)	(285)	(284)	(283)	(282)	(281)	(280)	(279)	(3,410)
	b. Debt Component Grossed Up For Taxes (B)		(97)	(97)	(97)	(96)	(96)	(96)	(95)	(95)	(95)	(94)	(94)	(94)	(1,146)
6.	Total Return Component (C)		(386)	(385)	(384)	(382)	(382)	(381)	(379)	(378)	(377)	(375)	(374)	(373)	(4,556)
7.	Expenses:														
	a. Gains		0	0	0	(3,604)	0	0	0	0	0	0	0	0	(3,604)
	b. Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. SO_2 Allowance Expense		1,750	328	2,030	4,795	4,640	4,413	3,322	1,878	1,853	1,886	1,848	1,817	30,560
8.	Net Expenses (D)		1,750	328	2,030	1,191	4,640	4,413	3,322	1,878	1,853	1,886	1,848	1,817	26,956
9.	Total System Recoverable Expenses (Lines 6 + 8)		1,364	(57)	1,646	809	4,258	4,032	2,943	1,500	1,476	1,511	1,474	1,444	22,400
	a. Recoverable Costs Allocated to Energy		1,364	(57)	1,646	809	4,258	4,032	2,943	1,500	1,476	1,511	1,474	1,444	22,400
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9919197	0.9919498	0.9961474	0.9929449	0.9935407	0.9941458	0.9948436	0.9942533	0.9952677	0.9993134	0.9998909	0.9999235	
11.	Demand Jurisdictional Factor		0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	0.9674819	
12.	Retail Energy-Related Recoverable Costs (D)		1,353	(57)	1,640	803	4,230	4,008	2,928	1,491	1,469	1,510	1,474	1,444	22,293
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Juris. Recoverable Costs (Lines 12 + 13)		$1,353	($57)	$1,640	$803	$4,230	$4,008	$2,928	$1,491	$1,469	$1,510	$1,474	$1,444	$22,293

Notes:
(A) Line 4 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(B) Line 4 x 2.9324% x 1/12.
(C) Line 6 is reported on Schedules 6E and 7E
(D) Line 8 is reported on Schedules 4E and 5E
(E) Line 9a x Line 10
(F) Line 9b x Line 11

* Totals on this schedule may not foot due to rounding.

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DOCKET NO. 110007-EI
ECRC 2011 ACTUAL/ESTIMATED TRUE-UP
EXHIBIT HTB-2, DOCUMENT NO. 8, PAGE 26 OF 26

Form 42 - 9E

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Actual / Estimated Amount
January 2011 to December 2011

Calculation of Revenue Requirement Rate of Return
(In Dollars)

	(1)	(2)	(3)	(4)
	Jurisdictional Rate Base 2009 Test Year ($000)	Ratio %	Cost Rate %	Weighted Cost Rate %
Long Term Debt	$ 1,384,999	40.29%	6.80%	2.7397%
Short Term Debt	7,905	0.23%	2.75%	0.0063%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	99,502	2.89%	6.07%	0.1754%
Common Equity	1,632,612	47.49%	11.25%	5.3426%
Deferred ITC - Weighted Cost	8,964	0.26%	9.19%	0.0239%
Accumulated Deferred Income Taxes Zero Cost ITCs	303,629	8.83%	0.00%	0.0000%
Total	$ 3,437,611	100.00%		8.2879%

ITC split between Debt and Equity:

Long Term Debt	$ 1,384,999	Long Term Debt	45.78%
Short Term Debt	7,905	Short Term Debt	0.26%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	1,632,612	Equity - Common	53.96%
Total	$ 3,025,516	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = .0239% * 46.04%	0.0110%
Equity = .0239% * 53.96%	0.0129%
Weighted Cost	0.0239%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	5.3426%
Deferred ITC - Weighted Cost	0.0129%
	5.3555%
Times Tax Multiplier	1.628002
Total Equity Component	8.7188%

Total Debt Cost Rate:

Long Term Debt	2.7397%
Short Term Debt	0.0063%
Customer Deposits	0.1754%
Deferred ITC - Weighted Cost	0.0110%
Total Debt Component	2.9324%

Notes:
Column (1) - From Order No. PSC-09-0571-FOF-EI
Column (2) - Column (1) / Total Column (1)
Column (3) - From Order No. PSC-09-0571-FOF-EI
Column (4) - Column (2) x Column (3)

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ENVIRONMENTAL COST RECOVERY COMMISSION FORMS

JANUARY 2012 THROUGH DECEMBER 2012

Form 42 - 1P

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to Be Recovered

For the Projected Period
January 2012 to December 2012

Line	Energy ($)	Demand ($)	Total ($)
1. Total Jurisdictional Revenue Requirements for the projected period			
a. Projected O&M Activities (Form 42-2P, Lines 7, 8 & 9)	$21,832,135	$748,354	$22,580,489
b. Projected Capital Projects (Form 42-3P, Lines 7, 8 & 9)	61,341,759	145,333	61,487,092
c. Total Jurisdictional Revenue Requirements for the projected period (Lines 1a + 1b)	83,173,894	893,687	84,067,581
2. True-up for Estimated Over/(Under) Recovery for the current period January 2011 to December 2011 (Form 42-2E, Line 5 + 6 + 10)	(461,691)	(2,399)	(464,090)
3. Final True-up for the period January 2010 to December 2010 (Form 42-1A, Line 3)	(2,606,498)	(10,300)	(2,616,798)
4. Total Jurisdictional Amount to Be Recovered/(Refunded) in the projection period January 2012 to December 2012 (Line 1 - Line 2- Line 3)	86,242,083	906,386	87,148,469
5. Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier)	$86,304,177	$907,039	$87,211,216

Notes: Allocation to energy and demand in each period is in proportion to the respective period split of costs indicated on Lines 7 and 8 of Forms 42-5 and 42-7 of the actuals and estimates.

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 to December 2012

Form 42 - 2P

O&M Activities
(in Dollars)

Line		Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1.	Description of O&M Activities															
a.	Big Bend Unit 3 Flue Gas Desulfurization Integration	$359,100	$381,900	$405,600	$372,400	$356,800	$354,500	$360,600	$359,400	$421,200	$415,400	$343,700	$359,600	$4,490,200		$4,490,200
b.	Big Bend Units 1 & 2 Flue Gas Conditioning	0	0	0	0	0	0	0	0	0	0	0	0	0		0
c.	SO_2 Emissions Allowances	1,843	1,706	1,841	1,860	1,913	1,842	1,904	1,902	1,840	1,916	1,855	1,840	22,262		22,262
d.	Big Bend Units 1 & 2 FGD	725,500	684,000	726,200	857,500	720,600	717,900	$728,500	$726,000	$703,600	$703,400	$691,300	$850,600	8,835,100		8,835,100
e.	Big Bend PM Minimization and Monitoring	27,200	27,200	43,200	43,200	27,200	27,200	$27,200	$27,200	$43,200	$43,200	$27,200	$27,200	390,400		390,400
f.	Big Bend NO_x Emissions Reduction	8,000	58,000	58,000	59,000	40,000	28,000	$8,000	$8,000	$8,000	$59,000	$33,000	$28,000	395,000		395,000
g.	NPDES Annual Surveillance Fees	34,500	0	0	0	0	0	0	0	0	0	0	0	34,500	34,500	
h.	Gannon Thermal Discharge Study	5,000	5,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	20,000	20,000	
i.	Polk NO_x Reduction	2,500	2,500	2,500	5,000	2,500	2,500	2,500	2,500	2,500	5,000	2,500	2,500	35,000		35,000
j.	Bayside SCR and Ammonia	13,300	0	0	13,300	0	13,300	13,300	13,300	13,300	13,300	0	13,300	106,400		106,400
k.	Big Bend Unit 4 SOFA	0	0	0	0	0	0	0	0	0	0	0	0	0		0
l.	Big Bend Unit 1 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
m.	Big Bend Unit 2 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
n.	Big Bend Unit 3 Pre-SCR	0	0	0	0	0	0	0	0	0	0	0	0	0		0
o.	Clean Water Act Section 316(b) Phase II Study	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	2,500	30,000	30,000	
p.	Arsenic Groundwater Standard Program	50,000	175,000	292,000	50,000	80,000	0	10,000	0	0	10,000	0	0	667,000	667,000	
q.	Big Bend 1 SCR	217,241	192,498	221,640	146,776	217,913	215,192	221,181	219,532	214,236	207,120	207,204	185,956	2,466,489		2,466,489
r.	Big Bend 2 SCR	227,272	200,265	228,434	148,973	223,002	219,184	225,799	224,397	219,470	211,541	212,229	195,865	2,536,432		2,536,432
s.	Big Bend 3 SCR	130,580	115,928	105,905	150,316	131,407	133,040	135,941	134,313	88,135	125,999	122,203	139,266	1,513,033		1,513,033
t.	Big Bend 4 SCR	84,244	59,390	100,538	94,714	81,513	82,195	86,772	85,960	101,330	65,215	72,579	83,820	998,269		998,269
u.	Clean Air Mercury Rule	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	2,000	24,000		24,000
v.	Greenhouse Gas Reduction Program	0	0	0	0	40,000	0	0	0	0	0	0	0	40,000		40,000
2.	Total of O&M ActivitieS	1,890,781	1,907,887	2,191,358	1,948,538	1,928,348	1,800,353	1,827,197	1,808,005	1,822,310	1,866,592	1,719,269	1,893,447	22,604,085	$751,500	$21,852,585
3.	Recoverable Costs Allocated to Energy	1,798,781	1,725,387	1,895,858	1,895,038	1,844,848	1,796,853	1,813,697	1,804,505	1,818,810	1,853,092	1,715,769	1,889,947	21,852,585		
4.	Recoverable Costs Allocated to Demand	92,000	182,500	295,500	53,500	83,500	3,500	13,500	3,500	3,500	13,500	3,500	3,500	751,500		
5.	Retail Energy Jurisdictional Factor	0.9997895	0.9999343	0.9999774	0.9998727	0.9987957	0.9980413	0.9979397	0.9975653	0.9983219	0.9986438	0.9998917	0.9999727			
6.	Retail Demand Jurisdictional Factor	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152			
7.	Jurisdictional Energy Recoverable Costs (A)	1,798,402	1,725,274	1,895,815	1,894,797	1,842,626	1,793,334	1,809,960	1,800,112	1,815,758	1,850,579	1,715,583	1,889,895	21,832,135		
8.	Jurisdictional Demand Recoverable Costs (B)	91,615	181,736	294,263	53,276	83,151	3,485	13,444	3,485	3,485	13,444	3,485	3,485	748,354		
9.	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$1,890,017	$1,907,010	$2,190,078	$1,948,073	$1,925,777	$1,796,819	$1,823,404	$1,803,597	$1,819,243	$1,864,023	$1,719,068	$1,893,380	$22,580,489		

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

DOCKET NO. 110007-EI
ECRC 2012 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 2

Form 42-3P

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 to December 2012

Capital Investment Projects-Recoverable Costs

(in Dollars)

Line		Description (A)	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total	Method of Classification Demand	Method of Classification Energy
1	a.	Big Bend Unit 3 Flue Gas Desulfurization Integration	$60,858	$60,705	$60,607	$60,701	$60,942	$61,298	$62,511	$63,839	$65,495	$67,171	$68,435	$75,840	$768,402		$768,402
	b.	Big Bend Units 1 and 2 Flue Gas Conditioning	32,768	32,639	32,508	32,378	32,247	32,118	31,987	31,857	31,727	31,597	31,467	31,336	384,629		384,629
	c.	Big Bend Unit 4 Continuous Emissions Monitors	6,269	6,255	6,240	6,225	6,211	6,196	6,181	6,167	6,152	6,137	6,122	6,108	74,263		74,263
	d.	Big Bend Fuel Oil Tank # 1 Upgrade	4,229	4,220	4,209	4,198	4,188	4,177	4,166	4,157	4,146	4,136	4,125	4,114	50,065	$ 50,065	
	e.	Big Bend Fuel Oil Tank # 2 Upgrade	6,957	6,939	6,922	6,905	6,888	6,871	6,854	6,836	6,819	6,802	6,784	6,767	82,344	82,344	
	f.	Phillips Upgrade Tank # 1 for FDEP	446	445	444	442	441	440	438	437	436	434	433	431	5,267	5,267	
	g.	Phillips Upgrade Tank # 4 for FDEP	701	699	696	695	692	690	688	686	683	682	679	676	8,267	8,267	
	h.	Big Bend Unit 1 Classifier Replacement	10,499	10,465	10,429	10,394	10,359	10,323	10,288	10,254	10,219	10,183	10,148	10,113	123,674		123,674
	i.	Big Bend Unit 2 Classifier Replacement	7,625	7,599	7,575	7,550	7,526	7,501	7,476	7,451	7,427	7,402	7,377	7,352	89,861		89,861
	j.	Big Bend Section 114 Mercury Testing Platform	1,072	1,071	1,068	1,067	1,064	1,063	1,060	1,059	1,056	1,055	1,053	1,051	12,739		12,739
	k.	Big Bend Units 1 & 2 FGD	729,317	731,137	732,627	737,838	739,557	741,263	739,278	737,180	735,049	732,900	730,751	728,603	8,815,500		8,815,500
	l.	Big Bend FGD Optimization and Utilization	198,814	198,410	198,005	197,601	197,196	196,793	196,388	195,984	195,579	195,176	194,771	194,366	2,359,083		2,359,083
	m.	Big Bend NO_x Emissions Reduction	64,574	64,493	64,413	64,331	64,251	64,170	64,089	64,008	63,926	63,846	63,765	63,684	769,550		769,550
	n.	Big Bend PM Minimization and Monitoring	87,164	86,957	86,750	86,544	86,337	86,179	89,492	92,828	92,767	92,707	92,645	95,982	1,076,352		1,076,352
	o.	Polk NO_x Emissions Reduction	15,506	15,463	15,421	15,377	15,334	15,291	15,248	15,205	15,163	15,120	15,076	15,033	183,237		183,237
	p.	Big Bend Unit 4 SOFA	25,578	25,528	25,479	25,429	25,379	25,329	25,280	25,230	25,181	25,130	25,081	25,031	303,655		303,655
	q.	Big Bend Unit 1 Pre-SCR	17,905	17,861	17,817	17,773	17,729	17,685	17,640	17,596	17,552	17,508	17,464	17,420	211,950		211,950
	r.	Big Bend Unit 2 Pre-SCR	17,065	17,025	16,985	16,946	16,906	16,866	16,827	16,787	16,747	16,708	16,668	16,629	202,159		202,159
	s.	Big Bend Unit 3 Pre-SCR	29,534	29,478	29,422	29,366	29,310	29,253	29,196	29,140	29,084	29,028	28,972	28,914	350,697		350,697
	t.	Big Bend Unit 1 SCR	966,183	964,374	962,564	960,754	958,944	957,134	955,324	953,514	951,704	949,895	948,084	946,275	11,474,749		11,474,749
	u.	Big Bend Unit 2 SCR	1,043,796	1,044,298	1,044,801	1,045,303	1,043,379	1,043,881	1,044,384	1,042,459	1,040,535	1,038,609	1,036,685	1,037,188	12,505,318		12,505,318
	v.	Big Bend Unit 3 SCR	862,736	861,306	859,876	858,445	857,015	855,585	854,155	852,724	851,294	849,864	848,434	847,004	10,258,438		10,258,438
	w.	Big Bend Unit 4 SCR	655,721	654,667	653,612	652,558	651,504	650,449	649,395	648,341	647,286	646,232	645,177	644,123	7,799,065		7,799,065
	x.	Big Bend FGD System Reliability	245,482	280,271	289,972	295,198	296,302	296,387	296,230	295,733	295,236	294,739	294,243	293,746	3,473,539		3,473,539
	y.	Clean Air Mercury Rule	13,872	13,940	13,912	13,884	13,855	13,924	13,992	13,964	13,936	13,908	13,879	13,850	166,916		166,916
	z.	SO_2 Emissions Allowances (B)	(372)	(370)	(370)	(369)	(368)	(366)	(365)	(365)	(363)	(362)	(361)	(360)	(4,391)		(4,391)
2		Total Investment Projects - Recoverable Costs	5,104,299	5,135,875	5,141,984	5,147,533	5,143,188	5,140,500	5,138,202	5,133,071	5,124,836	5,116,607	5,107,957	5,111,276	61,545,328	$ 145,943	$ 61,399,385
3.		Recoverable Costs Allocated to Energy	5,091,966	5,123,572	5,129,713	5,135,293	5,130,979	5,128,322	5,126,056	5,120,955	5,112,752	5,104,553	5,095,936	5,099,288	61,399,385		
4.		Recoverable Costs Allocated to Demand	12,333	12,303	12,271	12,240	12,209	12,178	12,146	12,116	12,084	12,054	12,021	11,988	145,943		
5.		Retail Energy Jurisdictional Factor	0.9997895	0.9999343	0.9999774	0.9998727	0.9987957	0.9980413	0.9979397	0.9975653	0.9983219	0.9986438	0.9998917	0.9999727			
6		Retail Demand Jurisdictional Factor	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152			
7.		Jurisdictional Energy Recoverable Costs (C)	5,090,894	5,123,235	5,129,597	5,134,639	5,124,800	5,118,277	5,115,495	5,108,487	5,104,172	5,097,630	5,095,384	5,099,149	61,341,759		
8.		Jurisdictional Demand Recoverable Costs (D)	12,281	12,252	12,220	12,189	12,158	12,127	12,095	12,065	12,033	12,004	11,971	11,938	145,333		
9		Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$5,103,175	$5,135,487	$5,141,817	$5,146,828	$5,136,958	$5,130,404	$5,127,590	$5,120,552	$5,116,205	$5,109,634	$5,107,355	$5,111,087	$61,487,092		

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

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DOCKET NO. 110007-EI
ECRC 2012 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 3

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Flue Gas Desulfurization Integration
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$11,338	$39,682	$41,603	$63,252	$218,261	$86,824	$285,803	$91,029	$201,017	$1,355,919	$2,394,728
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	$8,239,658	
3.	Less: Accumulated Depreciation	(3,590,325)	(3,606,118)	(3,621,911)	(3,637,704)	(3,653,497)	(3,669,290)	(3,685,083)	(3,700,876)	(3,716,669)	(3,732,462)	(3,748,255)	(3,764,048)	(3,779,841)	
4.	CWIP - Non-Interest Bearing	0	0	0	11,338	51,020	92,623	155,875	374,136	460,960	746,763	837,792	1,038,809	2,394,728	
5.	Net Investment (Lines 2 + 3 + 4)	$4,649,333	4,633,540	4,617,747	4,613,292	4,637,181	4,662,991	4,710,450	4,912,918	4,983,949	5,253,959	5,329,195	5,514,419	6,854,545	
6.	Average Net Investment		4,641,437	4,625,644	4,615,520	4,625,237	4,650,086	4,686,721	4,811,684	4,948,434	5,118,954	5,291,577	5,421,807	6,184,482	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		33,723	33,608	33,535	33,605	33,786	34,052	34,960	35,954	37,193	38,447	39,393	44,934	$433,190
	b. Debt Component Grossed Up For Taxes (C)		11,342	11,304	11,279	11,303	11,363	11,453	11,758	12,092	12,509	12,931	13,249	15,113	145,696
8.	Investment Expenses														
	a. Depreciation (D)		15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	15,793	189,516
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		60,858	60,705	60,607	60,701	60,942	61,298	62,511	63,839	65,495	67,171	68,435	75,840	768,402
	a. Recoverable Costs Allocated to Energy		60,858	60,705	60,607	60,701	60,942	61,298	62,511	63,839	65,495	67,171	68,435	75,840	768,402
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9997895	0.9999343	0.9999774	0.9998727	0.9987957	0.9980413	0.9979397	0.9975653	0.9983219	0.9986438	0.9998917	0.9999727	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		60,845	60,701	60,606	60,693	60,869	61,178	62,382	63,684	65,385	67,080	68,428	75,838	767,689
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$60,845	$60,701	$60,606	$60,693	$60,869	$61,178	$62,382	$63,684	$65,385	$67,080	$68,428	$75,838	$767,689

Notes:
(A) Applicable depreciable base for Big Bend; account 312.45
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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DOCKET NO. 110007-EI
ECRC 2012 PROJECTION FILING
EXHIBIT HTB-3, DOCUMENT NO. 4, PAGE 1 OF 26

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 Flue Gas Conditioning
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	$5,017,734	
3.	Less: Accumulated Depreciation	(3,017,126)	(3,030,535)	(3,043,944)	(3,057,353)	(3,070,762)	(3,084,171)	(3,097,580)	(3,110,989)	(3,124,398)	(3,137,807)	(3,151,216)	(3,164,625)	(3,178,034)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,000,608	1,987,199	1,973,790	1,960,381	1,946,972	1,933,563	1,920,154	1,906,745	1,893,336	1,879,927	1,866,518	1,853,109	1,839,700	
6.	Average Net Investment		1,993,904	1,980,495	1,967,086	1,953,677	1,940,268	1,926,859	1,913,450	1,900,041	1,886,632	1,873,223	1,859,814	1,846,405	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		14,487	14,390	14,292	14,195	14,097	14,000	13,902	13,805	13,708	13,610	13,513	13,415	$167,414
	b. Debt Component Grossed Up For Taxes (C)		4,872	4,840	4,807	4,774	4,741	4,709	4,676	4,643	4,610	4,578	4,545	4,512	56,307
8.	Investment Expenses														
	a. Depreciation (D)		13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	13,409	160,908
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		32,768	32,639	32,508	32,378	32,247	32,118	31,987	31,857	31,727	31,597	31,467	31,336	384,629
	a. Recoverable Costs Allocated to Energy		32,768	32,639	32,508	32,378	32,247	32,118	31,987	31,857	31,727	31,597	31,467	31,336	384,629
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9997895	0.9999343	0.9999774	0.9998727	0.9987957	0.9980413	0.9979397	0.9975653	0.9983219	0.9986438	0.9998917	0.9999727	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		32,761	32,637	32,507	32,374	32,208	32,055	31,921	31,779	31,674	31,554	31,464	31,335	384,269
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$32,761	$32,637	$32,507	$32,374	$32,208	$32,055	$31,921	$31,779	$31,674	$31,554	$31,464	$31,335	$384,269

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($2,676,217) and 312.42 ($2,341,517)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 3.3% and 3.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 Continuous Emissions Monitors
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	$866,211	
3.	Less: Accumulated Depreciation	(375,845)	(377,361)	(378,877)	(380,393)	(381,909)	(383,425)	(384,941)	(386,457)	(387,973)	(389,489)	(391,005)	(392,521)	(394,037)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$490,366	488,850	487,334	485,818	484,302	482,786	481,270	479,754	478,238	476,722	475,206	473,690	472,174	
6.	Average Net Investment		489,608	488,092	486,576	485,060	483,544	482,028	480,512	478,996	477,480	475,964	474,448	472,932	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		3,557	3,546	3,535	3,524	3,513	3,502	3,491	3,480	3,469	3,458	3,447	3,436	$41,958
	b. Debt Component Grossed Up For Taxes (C)		1,196	1,193	1,189	1,185	1,182	1,178	1,174	1,171	1,167	1,163	1,159	1,156	14,113
8.	Investment Expenses														
	a. Depreciation (D)		1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	1,516	18,192
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		6,269	6,255	6,240	6,225	6,211	6,196	6,181	6,167	6,152	6,137	6,122	6,108	74,263
	a. Recoverable Costs Allocated to Energy		6,269	6,255	6,240	6,225	6,211	6,196	6,181	6,167	6,152	6,137	6,122	6,108	74,263
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9997895	0.9999343	0.9999774	0.9998727	0.9987957	0.9980413	0.9979397	0.9975653	0.9983219	0.9986438	0.9998917	0.9999727	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		6,268	6,255	6,240	6,224	6,204	6,184	6,168	6,152	6,142	6,129	6,121	6,108	74,195
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$6,268	$6,255	$6,240	$6,224	$6,204	$6,184	$6,168	$6,152	$6,142	$6,129	$6,121	$6,108	$74,195

Notes:
(A) Applicable depreciable base for Big Bend; account 315.44
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 to December 2012

Form 42-4P
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Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 1 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	$497,578	
3.	Less: Accumulated Depreciation	(172,432)	(173,510)	(174,588)	(175,666)	(176,744)	(177,822)	(178,900)	(179,978)	(181,056)	(182,134)	(183,212)	(184,290)	(185,368)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$325,146	324,068	322,990	321,912	320,834	319,756	318,678	317,600	316,522	315,444	314,366	313,288	312,210	
6.	Average Net Investment		324,607	323,529	322,451	321,373	320,295	319,217	318,139	317,061	315,983	314,905	313,827	312,749	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		2,358	2,351	2,343	2,335	2,327	2,319	2,311	2,304	2,296	2,288	2,280	2,272	$27,784
	b. Debt Component Grossed Up For Taxes (C)		793	791	788	785	783	780	777	775	772	770	767	764	9,345
8.	Investment Expenses														
	a. Depreciation (D)		1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	1,078	12,936
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		4,229	4,220	4,209	4,198	4,188	4,177	4,166	4,157	4,146	4,136	4,125	4,114	50,065
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		4,229	4,220	4,209	4,198	4,188	4,177	4,166	4,157	4,146	4,136	4,125	4,114	50,065
10.	Energy Jurisdictional Factor		0.9997895	0.9999343	0.9999774	0.9998727	0.9987957	0.9980413	0.9979397	0.9975653	0.9983219	0.9986438	0.9998917	0.9999727	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		4,211	4,202	4,191	4,180	4,170	4,160	4,149	4,140	4,129	4,119	4,108	4,097	49,856
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$4,211	$4,202	$4,191	$4,180	$4,170	$4,160	$4,149	$4,140	$4,129	$4,119	$4,108	$4,097	$49,856

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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ECRC 2012 PROJECTION FILING
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Fuel Oil Tank # 2 Upgrade
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	$818,401	
3.	Less: Accumulated Depreciation	(283,624)	(285,397)	(287,170)	(288,943)	(290,716)	(292,489)	(294,262)	(296,035)	(297,808)	(299,581)	(301,354)	(303,127)	(304,900)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$534,777	533,004	531,231	529,458	527,685	525,912	524,139	522,366	520,593	518,820	517,047	515,274	513,501	
6.	Average Net Investment		533,891	532,118	530,345	528,572	526,799	525,026	523,253	521,480	519,707	517,934	516,161	514,388	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		3,879	3,866	3,853	3,840	3,828	3,815	3,802	3,789	3,776	3,763	3,750	3,737	$45,698
	b. Debt Component Grossed Up For Taxes (C)		1,305	1,300	1,296	1,292	1,287	1,283	1,279	1,274	1,270	1,266	1,261	1,257	15,370
8.	Investment Expenses														
	a. Depreciation (D)		1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	21,276
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		6,957	6,939	6,922	6,905	6,888	6,871	6,854	6,836	6,819	6,802	6,784	6,767	82,344
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		6,957	6,939	6,922	6,905	6,888	6,871	6,854	6,836	6,819	6,802	6,784	6,767	82,344
10.	Energy Jurisdictional Factor		0.9997895	0.9999343	0.9999774	0.9998727	0.9987957	0.9980413	0.9979397	0.9975653	0.9983219	0.9986438	0.9998917	0.9999727	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		6,928	6,910	6,893	6,876	6,859	6,842	6,825	6,807	6,790	6,774	6,756	6,739	81,999
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$6,928	$6,910	$6,893	$6,876	$6,859	$6,842	$6,825	$6,807	$6,790	$6,774	$6,756	$6,739	$81,999

Notes:
(A) Applicable depreciable base for Big Bend; account 312.40
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Phillips Upgrade Tank # 1 for FDEP
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	$57,277	
3.	Less: Accumulated Depreciation	(25,968)	(26,111)	(26,254)	(26,397)	(26,540)	(26,683)	(26,826)	(26,969)	(27,112)	(27,255)	(27,398)	(27,541)	(27,684)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$31,309	31,166	31,023	30,880	30,737	30,594	30,451	30,308	30,165	30,022	29,879	29,736	29,593	
6.	Average Net Investment		31,238	31,095	30,952	30,809	30,666	30,523	30,380	30,237	30,094	29,951	29,808	29,665	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		227	226	225	224	223	222	221	220	219	218	217	216	$2,658
	b. Debt Component Grossed Up For Taxes (C)		76	76	76	75	75	75	74	74	74	73	73	72	893
8.	Investment Expenses														
	a. Depreciation (D)		143	143	143	143	143	143	143	143	143	143	143	143	1,716
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		446	445	444	442	441	440	438	437	436	434	433	431	5,267
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		446	445	444	442	441	440	438	437	436	434	433	431	5,267
10.	Energy Jurisdictional Factor		0.9997895	0.9999343	0.9999774	0.9998727	0.9987957	0.9980413	0.9979397	0.9975653	0.9983219	0.9986438	0.9998917	0.9999727	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		444	443	442	440	439	438	436	435	434	432	431	429	5,243
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$444	$443	$442	$440	$439	$438	$436	$435	$434	$432	$431	$429	$5,243

Notes:
(A) Applicable depreciable base for Phillips; account 342.28
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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ECRC 2012 PROJECTION FILING
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Phillips Upgrade Tank # 4 for FDEP
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	$90,472	
3.	Less: Accumulated Depreciation	(41,435)	(41,661)	(41,887)	(42,113)	(42,339)	(42,565)	(42,791)	(43,017)	(43,243)	(43,469)	(43,695)	(43,921)	(44,147)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$49,037	48,811	48,585	48,359	48,133	47,907	47,681	47,455	47,229	47,003	46,777	46,551	46,325	
6.	Average Net Investment		48,924	48,698	48,472	48,246	48,020	47,794	47,568	47,342	47,116	46,890	46,664	46,438	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		355	354	352	351	349	347	346	344	342	341	339	337	$4,157
	b. Debt Component Grossed Up For Taxes (C)		120	119	118	118	117	117	116	116	115	115	114	113	1,398
8.	Investment Expenses														
	a. Depreciation (D)		226	226	226	226	226	226	226	226	226	226	226	226	2,712
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		701	699	696	695	692	690	688	686	683	682	679	676	8,267
	a. Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Recoverable Costs Allocated to Demand		701	699	696	695	692	690	688	686	683	682	679	676	8,267
10.	Energy Jurisdictional Factor		0.9997895	0.9999343	0.9999774	0.9998727	0.9987957	0.9980413	0.9979397	0.9975653	0.9983219	0.9986438	0.9998917	0.9999727	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
13.	Retail Demand-Related Recoverable Costs (F)		698	696	693	692	689	687	685	683	680	679	676	673	8,231
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$698	$696	$693	$692	$689	$687	$685	$683	$680	$679	$676	$673	$8,231

Notes:
(A) Applicable depreciable base for Phillips; account 342.28
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	$1,316,257	
3.	Less: Accumulated Depreciation	(605,912)	(609,532)	(613,152)	(616,772)	(620,392)	(624,012)	(627,632)	(631,252)	(634,872)	(638,492)	(642,112)	(645,732)	(649,352)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$710,345	706,725	703,105	699,485	695,865	692,245	688,625	685,005	681,385	677,765	674,145	670,525	666,905	
6.	Average Net Investment		708,535	704,915	701,295	697,675	694,055	690,435	686,815	683,195	679,575	675,955	672,335	668,715	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		5,148	5,122	5,095	5,069	5,043	5,016	4,990	4,964	4,938	4,911	4,885	4,859	$60,040
	b. Debt Component Grossed Up For Taxes (C)		1,731	1,723	1,714	1,705	1,696	1,687	1,678	1,670	1,661	1,652	1,643	1,634	20,194
8.	Investment Expenses														
	a. Depreciation (D)		3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	3,620	43,440
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		10,499	10,465	10,429	10,394	10,359	10,323	10,288	10,254	10,219	10,183	10,148	10,113	123,674
	a. Recoverable Costs Allocated to Energy		10,499	10,465	10,429	10,394	10,359	10,323	10,288	10,254	10,219	10,183	10,148	10,113	123,674
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9997895	0.9999343	0.9999774	0.9998727	0.9987957	0.9980413	0.9979397	0.9975653	0.9983219	0.9986438	0.9998917	0.9999727	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		10,497	10,464	10,429	10,393	10,347	10,303	10,267	10,229	10,202	10,169	10,147	10,113	123,560
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$10,497	$10,464	$10,429	$10,393	$10,347	$10,303	$10,267	$10,229	$10,202	$10,169	$10,147	$10,113	$123,560

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Classifier Replacement
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	$984,794	
3.	Less: Accumulated Depreciation	(460,278)	(462,822)	(465,366)	(467,910)	(470,454)	(472,998)	(475,542)	(478,086)	(480,630)	(483,174)	(485,718)	(488,262)	(490,806)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$524,516	521,972	519,428	516,884	514,340	511,796	509,252	506,708	504,164	501,620	499,076	496,532	493,988	
6.	Average Net Investment		523,244	520,700	518,156	515,612	513,068	510,524	507,980	505,436	502,892	500,348	497,804	495,260	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		3,802	3,783	3,765	3,746	3,728	3,709	3,691	3,672	3,654	3,635	3,617	3,598	$44,400
	b. Debt Component Grossed Up For Taxes (C)		1,279	1,272	1,266	1,260	1,254	1,248	1,241	1,235	1,229	1,223	1,216	1,210	14,933
8.	Investment Expenses														
	a. Depreciation (D)		2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	2,544	30,528
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		7,625	7,599	7,575	7,550	7,526	7,501	7,476	7,451	7,427	7,402	7,377	7,352	89,861
	a. Recoverable Costs Allocated to Energy		7,625	7,599	7,575	7,550	7,526	7,501	7,476	7,451	7,427	7,402	7,377	7,352	89,861
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9997695	0.9999343	0.9999774	0.9998727	0.9987957	0.9980413	0.9979397	0.9975653	0.9983219	0.9986438	0.9998917	0.9999727	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		7,623	7,599	7,575	7,549	7,517	7,486	7,461	7,433	7,415	7,392	7,376	7,352	89,778
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$7,623	$7,599	$7,575	$7,549	$7,517	$7,486	$7,461	$7,433	$7,415	$7,392	$7,376	$7,352	$89,778

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Section 114 Mercury Testing Platform
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	$120,737	
3.	Less: Accumulated Depreciation	(30,883)	(31,084)	(31,285)	(31,486)	(31,687)	(31,888)	(32,089)	(32,290)	(32,491)	(32,692)	(32,893)	(33,094)	(33,295)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$89,854	89,653	89,452	89,251	89,050	88,849	88,648	88,447	88,246	88,045	87,844	87,643	87,442	
6.	Average Net Investment		89,754	89,553	89,352	89,151	88,950	88,749	88,548	88,347	88,146	87,945	87,744	87,543	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		652	651	649	648	646	645	643	642	640	639	638	636	$7,729
	b. Debt Component Grossed Up For Taxes (C)		219	219	218	218	217	217	216	216	215	215	214	214	2,598
8.	Investment Expenses														
	a. Depreciation (D)		201	201	201	201	201	201	201	201	201	201	201	201	2,412
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		1,072	1,071	1,068	1,067	1,064	1,063	1,060	1,059	1,056	1,055	1,053	1,051	12,739
	a. Recoverable Costs Allocated to Energy		1,072	1,071	1,068	1,067	1,064	1,063	1,060	1,059	1,056	1,055	1,053	1,051	12,739
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9997895	0.9999343	0.9999774	0.9998727	0.9987957	0.9980413	0.9979397	0.9975653	0.9983219	0.9986438	0.9998917	0.9999727	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		1,072	1,071	1,068	1,067	1,063	1,061	1,058	1,056	1,054	1,054	1,053	1,051	12,728
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$1,072	$1,071	$1,068	$1,067	$1,063	$1,061	$1,058	$1,056	$1,054	$1,054	$1,053	$1,051	$12,728

Notes:
(A) Applicable depreciable base for Big Bend; account 311.40
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.0%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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ECRC 2012 PROJECTION FILING
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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Units 1 and 2 FGD
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$303,242	$498,617	$236,700	$491,878	$263,642	$18,870	$5,436	$2,261	$0	$0	$0	$0	$1,820,646
	b. Clearings to Plant		4,986	3,000	1,563,004	71,971	1,022,571	18,870	5,436	2,261	0	0	0	0	2,692,099
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$88,877,654	$88,882,640	$88,885,640	$90,448,644	$90,520,615	$91,543,185	$91,562,055	$91,567,491	$91,569,752	$91,569,752	$91,569,752	$91,569,752	$91,569,752	
3.	Less: Accumulated Depreciation	(36,800,075)	(37,014,863)	(37,229,663)	(37,444,470)	(37,663,054)	(37,881,812)	(38,103,041)	(38,324,316)	(38,545,604)	(38,766,898)	(38,988,192)	(39,209,486)	(39,430,780)	
4.	CWIP - Non-Interest Bearing	871,453	1,169,709	1,665,326	339,022	758,929	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$52,949,031	53,037,486	53,321,303	53,343,196	53,616,490	53,661,373	53,459,014	53,243,175	53,024,148	52,802,854	52,581,560	52,360,266	52,138,972	
6.	Average Net Investment		52,993,258	53,179,394	53,332,249	53,479,843	53,638,931	53,560,193	53,351,094	53,133,661	52,913,501	52,692,207	52,470,913	52,249,619	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		385,031	386,384	387,494	388,567	389,723	389,151	387,631	386,051	384,452	382,844	381,236	379,628	$4,628,192
	b. Debt Component Grossed Up For Taxes (C)		129,498	129,953	130,326	130,687	131,076	130,883	130,372	129,841	129,303	128,762	128,221	127,681	1,556,603
8.	Investment Expenses														
	a. Depreciation (D)		214,788	214,800	214,807	218,584	218,758	221,229	221,275	221,288	221,294	221,294	221,294	221,294	2,630,705
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		729,317	731,137	732,627	737,838	739,557	741,263	739,278	737,180	735,049	732,900	730,751	728,603	8,815,500
	a. Recoverable Costs Allocated to Energy		729,317	731,137	732,627	737,838	739,557	741,263	739,278	737,180	735,049	732,900	730,751	728,603	8,815,500
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9997895	0.9999343	0.9999774	0.9998727	0.9987957	0.9980413	0.9979397	0.9975653	0.9983219	0.9986438	0.9998917	0.9999727	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		729,163	731,089	732,610	737,744	738,666	739,811	737,755	735,385	733,816	731,906	730,672	728,583	8,807,200
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$729,163	$731,089	$732,610	$737,744	$738,666	$739,811	$737,755	$735,385	$733,816	$731,906	$730,672	$728,583	$8,807,200

Notes:
(A) Applicable depreciable base for Big Bend; account 312.46
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 2.9%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD Optimization and Utilization
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	$21,739,737	
3.	Less: Accumulated Depreciation	(5,531,197)	(5,572,839)	(5,614,481)	(5,656,123)	(5,697,765)	(5,739,407)	(5,781,049)	(5,822,691)	(5,864,333)	(5,905,975)	(5,947,617)	(5,989,259)	(6,030,901)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$16,208,540	16,166,898	16,125,256	16,083,614	16,041,972	16,000,330	15,958,688	15,917,046	15,875,404	15,833,762	15,792,120	15,750,478	15,708,836	
6.	Average Net Investment		16,187,719	16,146,077	16,104,435	16,062,793	16,021,151	15,979,509	15,937,867	15,896,225	15,854,583	15,812,941	15,771,299	15,729,657	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		117,615	117,312	117,009	116,707	116,404	116,102	115,799	115,497	115,194	114,892	114,589	114,286	$1,391,406
	b. Debt Component Grossed Up For Taxes (C)		39,557	39,456	39,354	39,252	39,150	39,049	38,947	38,845	38,743	38,642	38,540	38,438	467,973
8.	Investment Expenses														
	a. Depreciation (D)		41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	41,642	499,704
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		198,814	198,410	198,005	197,601	197,196	196,793	196,388	195,984	195,579	195,176	194,771	194,366	2,359,083
	a. Recoverable Costs Allocated to Energy		198,814	198,410	198,005	197,601	197,196	196,793	196,388	195,984	195,579	195,176	194,771	194,366	2,359,083
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9997895	0.9999343	0.9999774	0.9998727	0.9987957	0.9980413	0.9979397	0.9975653	0.9983219	0.9986438	0.9998917	0.9999727	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		198,772	198,397	198,001	197,576	196,959	196,408	195,983	195,507	195,251	194,911	194,750	194,361	2,356,876
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$198,772	$198,397	$198,001	$197,576	$196,959	$196,408	$195,983	$195,507	$195,251	$194,911	$194,750	$194,361	$2,356,876

Notes:
(A) Applicable depreciable base for Big Bend; accounts 311.45 ($39,818) and 312.45 ($21,699,919)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 1.5% and 2.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	$0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	$3,190,852	
3.	Less: Accumulated Depreciation	2,605,227	2,596,888	2,588,549	2,580,210	2,571,871	2,563,532	2,555,193	2,546,854	2,538,515	2,530,176	2,521,837	2,513,498	2,505,159	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$5,796,079	5,787,740	5,779,401	5,771,062	5,762,723	5,754,384	5,746,045	5,737,706	5,729,367	5,721,028	5,712,689	5,704,350	5,696,011	
6.	Average Net Investment		5,791,910	5,783,571	5,775,232	5,766,893	5,758,554	5,750,215	5,741,876	5,733,537	5,725,198	5,716,859	5,708,520	5,700,181	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		42,082	42,021	41,961	41,900	41,840	41,779	41,719	41,658	41,597	41,537	41,476	41,416	$500,986
	b. Debt Component Grossed Up For Taxes (C)		14,153	14,133	14,113	14,092	14,072	14,052	14,031	14,011	13,990	13,970	13,950	13,929	168,496
8.	Investment Expenses														
	a. Depreciation (D)		8,339	8,339	8,339	8,339	8,339	8,339	8,339	8,339	8,339	8,339	8,339	8,339	100,068
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		64,574	64,493	64,413	64,331	64,251	64,170	64,089	64,008	63,926	63,846	63,765	63,684	769,550
	a. Recoverable Costs Allocated to Energy		64,574	64,493	64,413	64,331	64,251	64,170	64,089	64,008	63,926	63,846	63,765	63,684	769,550
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9997895	0.9999343	0.9999774	0.9998727	0.9987957	0.9980413	0.9979397	0.9975653	0.9983219	0.9986438	0.9998917	0.9999727	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		64,560	64,489	64,412	64,323	64,174	64,044	63,957	63,852	63,819	63,759	63,758	63,682	768,829
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$64,560	$64,489	$64,412	$64,323	$64,174	$64,044	$63,957	$63,852	$63,819	$63,759	$63,758	$63,682	$768,829

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,675,171), 312.42 ($1,075,718), and 312.43 ($439,963)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 3.3%, 3.1%, and 2.6%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 to December 2012

Form 42-4P

Return on Capital Investments, Depreciation and Taxes
For Project: PM Minimization and Monitoring
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$10,000	$715,000	$15,000	$15,000	$15,000	$15,000	$715,000	$1,500,000
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	$0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$8,517,765	$8,517,765	$8,517,765	$8,517,765	$8,517,765	$8,517,765	$8,517,765	$8,517,765	$8,517,765	$8,517,765	$8,517,765	$8,517,765	$8,517,765	
3.	Less: Accumulated Depreciation	(1,722,767)	(1,744,059)	(1,765,351)	(1,786,643)	(1,807,935)	(1,829,227)	(1,850,519)	(1,871,811)	(1,893,103)	(1,914,395)	(1,935,687)	(1,956,979)	(1,978,271)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	10,000	725,000	740,000	755,000	770,000	785,000	1,500,000	
5.	Net Investment (Lines 2 + 3 + 4)	$6,794,998	6,773,706	6,752,414	6,731,122	6,709,830	6,688,538	6,677,246	7,370,954	7,364,662	7,358,370	7,352,078	7,345,786	8,039,494	
6.	Average Net Investment		6,784,352	6,763,060	6,741,768	6,720,476	6,699,184	6,682,892	7,024,100	7,367,808	7,361,516	7,355,224	7,348,932	7,692,640	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		49,293	49,138	48,983	48,829	48,674	48,556	51,035	53,532	53,486	53,441	53,395	55,892	$614,254
	b. Debt Component Grossed Up For Taxes (C)		16,579	16,527	16,475	16,423	16,371	16,331	17,165	18,004	17,989	17,974	17,958	18,798	206,594
8.	Investment Expenses														
	a. Depreciation (D)		21,292	21,292	21,292	21,292	21,292	21,292	21,292	21,292	21,292	21,292	21,292	21,292	255,504
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		87,164	86,957	86,750	86,544	86,337	86,179	89,492	92,828	92,767	92,707	92,645	95,982	1,076,352
	a. Recoverable Costs Allocated to Energy		87,164	86,957	86,750	86,544	86,337	86,179	89,492	92,828	92,767	92,707	92,645	95,982	1,076,352
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9997895	0.9999343	0.9999774	0.9998727	0.9987957	0.9980413	0.9979397	0.9975653	0.9983219	0.9986438	0.9998917	0.9999727	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		87,146	86,951	86,748	86,533	86,233	86,010	89,308	92,602	92,611	92,581	92,635	95,979	1,075,337
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$87,146	$86,951	$86,748	$86,533	$86,233	$86,010	$89,308	$92,602	$92,611	$92,581	$92,635	$95,979	$1,075,337

Notes:
(A) Applicable depreciable base for Big Bend; accounts 312.41 ($1,513,263), 312.42 ($5,153,072), 312.43 ($955,619), 315.41 ($17,504), 315.44 ($351,594), and 315.43 ($526,713)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 3.3%, 3.1%, 2.6%, 2.5%, 2.1%, and 2.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Polk NO_x Emissions Reduction
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	$1,561,473	
3.	Less: Accumulated Depreciation	(417,882)	(422,306)	(426,730)	(431,154)	(435,578)	(440,002)	(444,426)	(448,850)	(453,274)	(457,698)	(462,122)	(466,546)	(470,970)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,143,591	1,139,167	1,134,743	1,130,319	1,125,895	1,121,471	1,117,047	1,112,623	1,108,199	1,103,775	1,099,351	1,094,927	1,090,503	
6.	Average Net Investment		1,141,379	1,136,955	1,132,531	1,128,107	1,123,683	1,119,259	1,114,835	1,110,411	1,105,987	1,101,563	1,097,139	1,092,715	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		8,293	8,261	8,229	8,196	8,164	8,132	8,100	8,068	8,036	8,004	7,971	7,939	$97,393
	b. Debt Component Grossed Up For Taxes (C)		2,789	2,778	2,768	2,757	2,746	2,735	2,724	2,713	2,703	2,692	2,681	2,670	32,756
8.	Investment Expenses														
	a. Depreciation (D)		4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	4,424	53,088
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		15,506	15,463	15,421	15,377	15,334	15,291	15,248	15,205	15,163	15,120	15,076	15,033	183,237
	a. Recoverable Costs Allocated to Energy		15,506	15,463	15,421	15,377	15,334	15,291	15,248	15,205	15,163	15,120	15,076	15,033	183,237
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9997895	0.9999343	0.9999774	0.9998727	0.9987957	0.9980413	0.9979397	0.9975653	0.9983219	0.9986438	0.9998917	0.9999727	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		15,503	15,462	15,421	15,375	15,316	15,261	15,217	15,168	15,138	15,099	15,074	15,033	183,067
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$15,503	$15,462	$15,421	$15,375	$15,316	$15,261	$15,217	$15,168	$15,138	$15,099	$15,074	$15,033	$183,067

Notes:
(A) Applicable depreciable base for Polk; account 342.81
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SOFA
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	$2,558,730	
3.	Less: Accumulated Depreciation	(448,850)	(453,967)	(459,084)	(464,201)	(469,318)	(474,435)	(479,552)	(484,669)	(489,786)	(494,903)	(500,020)	(505,137)	(510,254)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,109,880	2,104,763	2,099,646	2,094,529	2,089,412	2,084,295	2,079,178	2,074,061	2,068,944	2,063,827	2,058,710	2,053,593	2,048,476	
6.	Average Net Investment		2,107,322	2,102,205	2,097,088	2,091,971	2,086,854	2,081,737	2,076,620	2,071,503	2,066,386	2,061,269	2,056,152	2,051,035	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		15,311	15,274	15,237	15,200	15,162	15,125	15,088	15,051	15,014	14,976	14,939	14,902	$181,279
	b. Debt Component Grossed Up For Taxes (C)		5,150	5,137	5,125	5,112	5,100	5,087	5,075	5,062	5,050	5,037	5,025	5,012	60,972
8.	Investment Expenses														
	a. Depreciation (D)		5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	5,117	61,404
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		25,578	25,528	25,479	25,429	25,379	25,329	25,280	25,230	25,181	25,130	25,081	25,031	303,655
	a. Recoverable Costs Allocated to Energy		25,578	25,528	25,479	25,429	25,379	25,329	25,280	25,230	25,181	25,130	25,081	25,031	303,655
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9997895	0.9999343	0.9999774	0.9998727	0.9987957	0.9980413	0.9979397	0.9975653	0.9983219	0.9986438	0.9998917	0.9999727	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		25,573	25,526	25,478	25,426	25,348	25,279	25,228	25,169	25,139	25,096	25,078	25,030	303,370
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$25,573	$25,526	$25,478	$25,426	$25,348	$25,279	$25,228	$25,169	$25,139	$25,096	$25,078	$25,030	$303,370

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.4%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	$1,649,121	
3.	Less: Accumulated Depreciation	(269,845)	(274,380)	(278,915)	(283,450)	(287,985)	(292,520)	(297,055)	(301,590)	(306,125)	(310,660)	(315,195)	(319,730)	(324,265)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,379,276	1,374,741	1,370,206	1,365,671	1,361,136	1,356,601	1,352,066	1,347,531	1,342,996	1,338,461	1,333,926	1,329,391	1,324,856	
6.	Average Net Investment		1,377,009	1,372,474	1,367,939	1,363,404	1,358,869	1,354,334	1,349,799	1,345,264	1,340,729	1,336,194	1,331,659	1,327,124	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		10,005	9,972	9,939	9,906	9,873	9,840	9,807	9,774	9,741	9,708	9,675	9,642	$117,882
	b. Debt Component Grossed Up For Taxes (C)		3,365	3,354	3,343	3,332	3,321	3,310	3,298	3,287	3,276	3,265	3,254	3,243	39,648
8.	Investment Expenses														
	a. Depreciation (D)		4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	4,535	54,420
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		17,905	17,861	17,817	17,773	17,729	17,685	17,640	17,596	17,552	17,508	17,464	17,420	211,950
	a. Recoverable Costs Allocated to Energy		17,905	17,861	17,817	17,773	17,729	17,685	17,640	17,596	17,552	17,508	17,464	17,420	211,950
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9997895	0.9999343	0.9999774	0.9998727	0.9987957	0.9980413	0.9979397	0.9975653	0.9983219	0.9986438	0.9998917	0.9999727	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		17,901	17,860	17,817	17,771	17,708	17,650	17,604	17,553	17,523	17,484	17,462	17,420	211,753
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$17,901	$17,860	$17,817	$17,771	$17,708	$17,650	$17,604	$17,553	$17,523	$17,484	$17,462	$17,420	$211,753

Notes:
(A) Applicable depreciable base for Big Bend; account 312.41
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.3%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	$0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	$1,581,887	
3.	Less: Accumulated Depreciation	(243,176)	(247,263)	(251,350)	(255,437)	(259,524)	(263,611)	(267,698)	(271,785)	(275,872)	(279,959)	(284,046)	(288,133)	(292,220)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$1,338,711	1,334,624	1,330,537	1,326,450	1,322,363	1,318,276	1,314,189	1,310,102	1,306,015	1,301,928	1,297,841	1,293,754	1,289,667	
6.	Average Net Investment		1,336,668	1,332,581	1,328,494	1,324,407	1,320,320	1,316,233	1,312,146	1,308,059	1,303,972	1,299,885	1,295,798	1,291,711	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		9,712	9,682	9,652	9,623	9,593	9,563	9,534	9,504	9,474	9,445	9,415	9,385	$114,582
	b. Debt Component Grossed Up For Taxes (C)		3,266	3,256	3,246	3,236	3,226	3,216	3,206	3,196	3,186	3,176	3,166	3,157	38,533
8.	Investment Expenses														
	a. Depreciation (D)		4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	4,087	49,044
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		17,065	17,025	16,985	16,946	16,906	16,866	16,827	16,787	16,747	16,708	16,668	16,629	202,159
	a. Recoverable Costs Allocated to Energy		17,065	17,025	16,985	16,946	16,906	16,866	16,827	16,787	16,747	16,708	16,668	16,629	202,159
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9997895	0.9999343	0.9999774	0.9998727	0.9987957	0.9980413	0.9979397	0.9975653	0.9983219	0.9986438	0.9998917	0.9999727	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		17,061	17,024	16,985	16,944	16,886	16,833	16,792	16,746	16,719	16,685	16,666	16,629	201,970
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$17,061	$17,024	$16,985	$16,944	$16,886	$16,833	$16,792	$16,746	$16,719	$16,685	$16,666	$16,629	$201,970

Notes:
(A) Applicable depreciable base for Big Bend; account 312.42
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 Pre-SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	$2,706,507	
3.	Less: Accumulated Depreciation	(259,586)	(265,391)	(271,196)	(277,001)	(282,806)	(288,611)	(294,416)	(300,221)	(306,026)	(311,831)	(317,636)	(323,441)	(329,246)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$2,446,921	2,441,116	2,435,311	2,429,506	2,423,701	2,417,896	2,412,091	2,406,286	2,400,481	2,394,676	2,388,871	2,383,066	2,377,261	
6.	Average Net Investment		2,444,019	2,438,214	2,432,409	2,426,604	2,420,799	2,414,994	2,409,189	2,403,384	2,397,579	2,391,774	2,385,969	2,380,164	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		17,757	17,715	17,673	17,631	17,589	17,547	17,504	17,462	17,420	17,378	17,336	17,293	$210,305
	b. Debt Component Grossed Up For Taxes (C)		5,972	5,958	5,944	5,930	5,916	5,901	5,887	5,873	5,859	5,845	5,831	5,816	70,732
8.	Investment Expenses														
	a. Depreciation (D)		5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	5,805	69,660
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		29,534	29,478	29,422	29,366	29,310	29,253	29,196	29,140	29,084	29,028	28,972	28,914	350,697
	a. Recoverable Costs Allocated to Energy		29,534	29,478	29,422	29,366	29,310	29,253	29,196	29,140	29,084	29,028	28,972	28,914	350,697
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9997895	0.9999343	0.9999774	0.9998727	0.9987957	0.9980413	0.9979397	0.9975653	0.9983219	0.9986438	0.9998917	0.9999727	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		29,528	29,476	29,421	29,362	29,275	29,196	29,136	29,069	29,035	28,989	28,969	28,913	350,369
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$29,528	$29,476	$29,421	$29,362	$29,275	$29,196	$29,136	$29,069	$29,035	$28,989	$28,969	$28,913	$350,369

Notes:
(A) Applicable depreciable base for Big Bend; account 312.43 ($1,995,677) and 315.43 ($710,830)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.6% and 2.5%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 1 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	$0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$84,099,312	$84,099,312	$84,099,312	$84,099,312	$84,099,312	$84,099,312	$84,099,312	$84,099,312	$84,099,312	$84,099,312	$84,099,312	$84,099,312	$84,099,312	
3.	Less: Accumulated Depreciation	(3,694,635)	(3,881,048)	(4,067,461)	(4,253,874)	(4,440,287)	(4,626,700)	(4,813,113)	(4,999,526)	(5,185,939)	(5,372,352)	(5,558,765)	(5,745,178)	(5,931,591)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$80,404,677	80,218,264	80,031,851	79,845,438	79,659,025	79,472,612	79,286,199	79,099,786	78,913,373	78,726,960	78,540,547	78,354,134	78,167,721	
6.	Average Net Investment		80,311,471	80,125,058	79,938,645	79,752,232	79,565,819	79,379,406	79,192,993	79,006,580	78,820,167	78,633,754	78,447,341	78,260,928	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		583,516	582,162	580,808	579,453	578,099	576,744	575,390	574,035	572,681	571,327	569,972	568,618	$6,912,805
	b. Debt Component Grossed Up For Taxes (C)		196,254	195,799	195,343	194,888	194,432	193,977	193,521	193,066	192,610	192,155	191,699	191,244	2,324,988
8.	Investment Expenses														
	a. Depreciation (D)		186,413	186,413	186,413	186,413	186,413	186,413	186,413	186,413	186,413	186,413	186,413	186,413	2,236,956
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		966,183	964,374	962,564	960,754	958,944	957,134	955,324	953,514	951,704	949,895	948,084	946,275	11,474,749
	a. Recoverable Costs Allocated to Energy		966,183	964,374	962,564	960,754	958,944	957,134	955,324	953,514	951,704	949,895	948,084	946,275	11,474,749
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9997895	0.9999343	0.9999774	0.9998727	0.9987957	0.9980413	0.9979397	0.9975653	0.9983219	0.9986438	0.9998917	0.9999727	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		965,980	964,311	962,542	960,632	957,789	955,259	953,356	951,192	950,107	948,607	947,981	946,249	11,464,005
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$965,980	$964,311	$962,542	$960,632	$957,789	$955,259	$953,356	$951,192	$950,107	$948,607	$947,981	$946,249	$11,464,005

Notes:
(A) Applicable depreciable base for Big Bend; account 311.41 ($25,152,322), 312.41 ($52,950,343), 315.41 ($5,040,180), and 316.41 ($956,467).
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 1.4%, 3.3%, 2.5% and 1.2%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 2 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$500,000	$0	$500,000	$0	$0	$500,000	$0	$0	$0	$0	$0	$500,000	$2,000,000
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	2,000,000	$2,000,000
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$92,352,524	$92,352,524	$92,352,524	$92,352,524	$92,352,524	$92,352,524	$92,352,524	$92,352,524	$92,352,524	$92,352,524	$92,352,524	$92,352,524	$94,352,524	
3.	Less: Accumulated Depreciation	(5,415,611)	(5,613,842)	(5,812,073)	(6,010,304)	(6,208,535)	(6,406,766)	(6,604,997)	(6,803,228)	(7,001,459)	(7,199,690)	(7,397,921)	(7,596,152)	(7,794,383)	
4.	CWIP - Non-Interest Bearing	0	500,000	500,000	1,000,000	1,000,000	1,000,000	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000	0	
5.	Net Investment (Lines 2 + 3 + 4)	$86,936,913	87,238,682	87,040,451	87,342,220	87,143,989	86,945,758	87,247,527	87,049,296	86,851,065	86,652,834	86,454,603	86,256,372	86,558,141	
6.	Average Net Investment		87,087,798	87,139,567	87,191,336	87,243,105	87,044,874	87,096,643	87,148,412	86,950,181	86,751,950	86,553,719	86,355,488	86,407,257	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		632,751	633,127	633,503	633,879	632,439	632,815	633,191	631,751	630,311	628,870	627,430	627,806	$7,577,873
	b. Debt Component Grossed Up For Taxes (C)		212,814	212,940	213,067	213,193	212,709	212,835	212,962	212,477	211,993	211,508	211,024	211,151	2,548,673
8.	Investment Expenses														
	a. Depreciation (D)		198,231	198,231	198,231	198,231	198,231	198,231	198,231	198,231	198,231	198,231	198,231	198,231	2,378,772
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		1,043,796	1,044,298	1,044,801	1,045,303	1,043,379	1,043,881	1,044,384	1,042,459	1,040,535	1,038,609	1,036,685	1,037,188	12,505,318
	a. Recoverable Costs Allocated to Energy		1,043,796	1,044,298	1,044,801	1,045,303	1,043,379	1,043,881	1,044,384	1,042,459	1,040,535	1,038,609	1,036,685	1,037,188	12,505,318
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9997895	0.9999343	0.9999774	0.9998727	0.9987957	0.9980413	0.9979397	0.9975653	0.9983219	0.9986438	0.9998917	0.9999727	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		1,043,576	1,044,229	1,044,777	1,045,170	1,042,122	1,041,836	1,042,232	1,039,921	1,038,789	1,037,200	1,036,573	1,037,160	12,493,585
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$1,043,576	$1,044,229	$1,044,777	$1,045,170	$1,042,122	$1,041,836	$1,042,232	$1,039,921	$1,038,789	$1,037,200	$1,036,573	$1,037,160	$12,493,585

Notes:
(A) Applicable depreciable base for Big Bend; account 311.42 ($25,208,869), 312.42 ($52,270,612), 315.42 ($15,914,427), and 316.42 ($958,616).
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 1.6%, 3.1%, 2.5% and 2.0%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 3 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$80,159,055	$80,159,055	$80,159,055	$80,159,055	$80,159,055	$80,159,055	$80,159,055	$80,159,055	$80,159,055	$80,159,055	$80,159,055	$80,159,055	$80,159,055	
3.	Less: Accumulated Depreciation	(6,400,212)	(6,547,514)	(6,694,816)	(6,842,118)	(6,989,420)	(7,136,722)	(7,284,024)	(7,431,326)	(7,578,628)	(7,725,930)	(7,873,232)	(8,020,534)	(8,167,836)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$73,758,843	73,611,541	73,464,239	73,316,937	73,169,635	73,022,333	72,875,031	72,727,729	72,580,427	72,433,125	72,285,823	72,138,521	71,991,219	
6.	Average Net Investment		73,685,192	73,537,890	73,390,588	73,243,286	73,095,984	72,948,682	72,801,380	72,654,078	72,506,776	72,359,474	72,212,172	72,064,870	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		535,372	534,302	533,232	532,161	531,091	530,021	528,951	527,880	526,810	525,740	524,670	523,599	$6,353,829
	b. Debt Component Grossed Up For Taxes (C)		180,062	179,702	179,342	178,982	178,622	178,262	177,902	177,542	177,182	176,822	176,462	176,103	2,136,985
8.	Investment Expenses														
	a. Depreciation (D)		147,302	147,302	147,302	147,302	147,302	147,302	147,302	147,302	147,302	147,302	147,302	147,302	1,767,624
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		862,736	861,306	859,876	858,445	857,015	855,585	854,155	852,724	851,294	849,864	848,434	847,004	10,258,438
	a. Recoverable Costs Allocated to Energy		862,736	861,306	859,876	858,445	857,015	855,585	854,155	852,724	851,294	849,864	848,434	847,004	10,258,438
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9997895	0.9999343	0.9999774	0.9998727	0.9987957	0.9980413	0.9979397	0.9975653	0.9983219	0.9986438	0.9998917	0.9999727	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		862,554	861,249	859,857	858,336	855,983	853,909	852,395	850,648	849,865	848,711	848,342	846,981	10,248,830
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$862,554	$861,249	$859,857	$858,336	$855,983	$853,909	$852,395	$850,648	$849,865	$848,711	$848,342	$846,981	$10,248,830

Notes:
(A) Applicable depreciable base for Big Bend; account 311.43 ($21,689,422), 312.43 ($43,953,995), 315.43 ($13,690,954), and 316.43 ($824,684).
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rates are 1.2%, 2.6%, 2.5%, and 2.7%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend Unit 4 SCR
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	$62,853,033	
3.	Less: Accumulated Depreciation	(6,448,484)	(6,557,082)	(6,665,680)	(6,774,278)	(6,882,876)	(6,991,474)	(7,100,072)	(7,208,670)	(7,317,268)	(7,425,866)	(7,534,464)	(7,643,062)	(7,751,660)	
4.	CWIP - Non-Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$56,404,549	56,295,951	56,187,353	56,078,755	55,970,157	55,861,559	55,752,961	55,644,363	55,535,765	55,427,167	55,318,569	55,209,971	55,101,373	
6.	Average Net Investment		56,350,250	56,241,652	56,133,054	56,024,456	55,915,858	55,807,260	55,698,662	55,590,064	55,481,466	55,372,868	55,264,270	55,155,672	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		409,422	408,633	407,844	407,055	406,266	405,477	404,688	403,899	403,110	402,321	401,532	400,743	$4,860,990
	b. Debt Component Grossed Up For Taxes (C)		137,701	137,436	137,170	136,905	136,640	136,374	136,109	135,844	135,578	135,313	135,047	134,782	1,634,899
8.	Investment Expenses														
	a. Depreciation (D)		108,598	108,598	108,598	108,598	108,598	108,598	108,598	108,598	108,598	108,598	108,598	108,598	1,303,176
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		655,721	654,667	653,612	652,558	651,504	650,449	649,395	648,341	647,286	646,232	645,177	644,123	7,799,065
	a. Recoverable Costs Allocated to Energy		655,721	654,667	653,612	652,558	651,504	650,449	649,395	648,341	647,286	646,232	645,177	644,123	7,799,065
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	-
10.	Energy Jurisdictional Factor		0.9997895	0.9999343	0.9999774	0.9998727	0.9987957	0.9980413	0.9979397	0.9975653	0.9983219	0.9986438	0.9998917	0.9999727	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		655,583	654,624	653,597	652,475	650,719	649,175	648,057	646,762	646,200	645,356	645,107	644,105	7,791,760
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$655,583	$654,624	$653,597	$652,475	$650,719	$649,175	$648,057	$646,762	$646,200	$645,356	$645,107	$644,105	$7,791,760

Notes:
(A) Applicable depreciable base for Big Bend; account 311.44 ($16,857,250), 312.44 ($34,665,822), 315.44 ($10,642,027), and 316.44 ($687,934).
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 1.4%, 2.4%, 2.1%, and 1.7%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Big Bend FGD System Reliability
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$1,076,879	$1,000,000	$700,000	$200,000	$50,000	$50,000	$0	$0	$0	$0	$0	$0	$3,076,879
	b. Clearings to Plant		13,066,851	1,000,000	700,000	200,000	50,000	50,000	0	0	0	0	0	0	15,066,851
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$11,566,029	$24,632,880	$25,632,880	$26,332,880	$26,532,880	$26,582,880	$26,632,880	$26,632,880	$26,632,880	$26,632,880	$26,632,880	$26,632,880	$26,632,880	
3.	Less: Accumulated Depreciation	(1,095,901)	(1,118,190)	(1,165,524)	(1,214,775)	(1,265,367)	(1,316,343)	(1,367,414)	(1,418,581)	(1,469,748)	(1,520,915)	(1,572,082)	(1,623,249)	(1,674,416)	
4.	CWIP - Non-Interest Bearing	11,989,972	0	0	0	0	0	0	0	0	0	0	0	0	
5.	Net Investment (Lines 2 + 3 + 4)	$22,460,100	23,514,690	24,467,356	25,118,105	25,267,513	25,266,537	25,265,466	25,214,299	25,163,132	25,111,965	25,060,798	25,009,631	24,958,464	
6.	Average Net Investment		22,987,395	23,991,023	24,792,730	25,192,809	25,267,025	25,266,001	25,239,882	25,188,715	25,137,548	25,086,381	25,035,214	24,984,047	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		167,019	174,311	180,136	183,043	183,582	183,574	183,385	183,013	182,641	182,269	181,898	181,526	$2,166,397
	b. Debt Component Grossed Up For Taxes (C)		56,174	58,626	60,585	61,563	61,744	61,742	61,678	61,553	61,428	61,303	61,178	61,053	728,627
8.	Investment Expenses														
	a. Depreciation (D)		22,289	47,334	49,251	50,592	50,976	51,071	51,167	51,167	51,167	51,167	51,167	51,167	578,515
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		245,482	280,271	289,972	295,198	296,302	296,387	296,230	295,733	295,236	294,739	294,243	293,746	3,473,539
	a. Recoverable Costs Allocated to Energy		245,482	280,271	289,972	295,198	296,302	296,387	296,230	295,733	295,236	294,739	294,243	293,746	3,473,539
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9997895	0.9999343	0.9999774	0.9998727	0.9987957	0.9980413	0.9979397	0.9975653	0.9983219	0.9986438	0.9998917	0.9999727	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		245,430	280,253	289,965	295,160	295,945	295,806	295,620	295,013	294,741	294,339	294,211	293,738	3,470,221
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$245,430	$280,253	$289,965	$295,160	$295,945	$295,806	$295,620	$295,013	$294,741	$294,339	$294,211	$293,738	$3,470,221

Notes:
(A) Applicable depreciable base for Big Bend; account 312.44 ($1,456,209) and 312.45 ($25,176,671)
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 2.4% and 2.3%.
(E) Line 9a x Line 10
(F) Line 9b x Line 11

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Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 to December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Clean Air Mercury Rule
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Expenditures/Additions		$20,000	$0	$0	$0	$0	$20,000	$0	$0	$0	$0	$0	$0	$40,000
	b. Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	$0
	c. Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d. Other		0	0	0	0	0	0	0	0	0	0	0	0	
2.	Plant-in-Service/Depreciation Base (A)	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	$1,169,053	
3.	Less: Accumulated Depreciation	(92,424)	(95,347)	(98,270)	(101,193)	(104,116)	(107,039)	(109,962)	(112,885)	(115,808)	(118,731)	(121,654)	(124,577)	(127,500)	
4.	CWIP - Non-Interest Bearing	42,458	62,458	62,458	62,458	62,458	62,458	82,458	82,458	82,458	82,458	82,458	82,458	82,458	
5.	Net Investment (Lines 2 + 3 + 4)	$1,119,087	1,136,164	1,133,241	1,130,318	1,127,395	1,124,472	1,141,549	1,138,626	1,135,703	1,132,780	1,129,857	1,126,934	1,124,011	
6.	Average Net Investment		1,127,626	1,134,703	1,131,780	1,128,857	1,125,934	1,133,011	1,140,088	1,137,165	1,134,242	1,131,319	1,128,396	1,125,473	
7.	Return on Average Net Investment														
	a. Equity Component Grossed Up For Taxes (B)		8,193	8,244	8,223	8,202	8,181	8,232	8,283	8,262	8,241	8,220	8,199	8,177	$98,657
	b. Debt Component Grossed Up For Taxes (C)		2,756	2,773	2,766	2,759	2,751	2,769	2,786	2,779	2,772	2,765	2,757	2,750	33,183
8.	Investment Expenses														
	a. Depreciation (D)		2,923	2,923	2,923	2,923	2,923	2,923	2,923	2,923	2,923	2,923	2,923	2,923	35,076
	b. Amortization		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d. Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e. Other		0	0	0	0	0	0	0	0	0	0	0	0	0
9.	Total System Recoverable Expenses (Lines 7 + 8)		13,872	13,940	13,912	13,884	13,855	13,924	13,992	13,964	13,936	13,908	13,879	13,850	166,916
	a. Recoverable Costs Allocated to Energy		13,872	13,940	13,912	13,884	13,855	13,924	13,992	13,964	13,936	13,908	13,879	13,850	166,916
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9997895	0.9999343	0.9999774	0.9998727	0.9987957	0.9980413	0.9979397	0.9975653	0.9983219	0.9986438	0.9998917	0.9999727	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (E)		13,869	13,939	13,912	13,882	13,838	13,897	13,963	13,930	13,913	13,889	13,877	13,850	166,759
13.	Retail Demand-Related Recoverable Costs (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		$13,869	$13,939	$13,912	$13,882	$13,838	$13,897	$13,963	$13,930	$13,913	$13,889	$13,877	$13,850	$166,759

Notes:
(A) Applicable depreciable base for Big Bend and Polk; accounts 315.40 ($1,169,053). Accounts 312.41, 312.43, 312.44, and 345.81 will be applicable when in-service.
(B) Line 6 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(C) Line 6 x 2.9324% x 1/12.
(D) Applicable depreciation rate is 3.0%, 3.3%, 2.6%, 2.4% and 3.1%
(E) Line 9a x Line 10
(F) Line 9b x Line 11

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 to December 2012

For Project: SO_2 Emissions Allowances
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Total
1.	Investments														
	a. Purchases/Transfers		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
	b. Sales/Transfers		$0	0	0	0	0	0	0	0	0	0	0	0	0
	c. Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	0
2.	Working Capital Balance														
	a. FERC 158.1 Allowance Inventory	$0	0	0	0	0	0	0	0	0	0	0	0	0	
	b. FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c. FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d. FERC 254.01 Regulatory Liabilities - Gains	(38,349)	(38,228)	(38,132)	(38,016)	(37,923)	(37,813)	(37,697)	(37,574)	(37,451)	(37,342)	(37,238)	(37,131)	(37,025)	
3.	Total Working Capital Balance	($38,349)	(38,228)	(38,132)	(38,016)	(37,923)	(37,813)	(37,697)	(37,574)	(37,451)	(37,342)	(37,238)	(37,131)	(37,025)	
4.	Average Net Working Capital Balance		($38,289)	($38,180)	($38,074)	($37,970)	($37,868)	($37,755)	($37,636)	($37,513)	($37,397)	($37,290)	($37,185)	($37,078)	
5.	Return on Average Net Working Capital Balance														
	a. Equity Component Grossed Up For Taxes (A)		(278)	(277)	(277)	(276)	(275)	(274)	(273)	(273)	(272)	(271)	(270)	(269)	(3,285)
	b. Debt Component Grossed Up For Taxes (B)		(94)	(93)	(93)	(93)	(93)	(92)	(92)	(92)	(91)	(91)	(91)	(91)	(1,106)
6.	Total Return Component (C)		(372)	(370)	(370)	(369)	(368)	(366)	(365)	(365)	(363)	(362)	(361)	(360)	(4,391)
7.	Expenses:														
	a. Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b. Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c. SO_2 Allowance Expense		1,843	1,706	1,841	1,860	1,913	1,842	1,904	1,902	1,840	1,916	1,855	1,840	22,262
8.	Net Expenses (D)		1,843	1,706	1,841	1,860	1,913	1,842	1,904	1,902	1,840	1,916	1,855	1,840	22,262
9.	Total System Recoverable Expenses (Lines 6 + 8)		1,471	1,336	1,471	1,491	1,545	1,476	1,539	1,537	1,477	1,554	1,494	1,480	17,871
	a. Recoverable Costs Allocated to Energy		1,471	1,336	1,471	1,491	1,545	1,476	1,539	1,537	1,477	1,554	1,494	1,480	17,871
	b. Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10.	Energy Jurisdictional Factor		0.9997895	0.9999343	0.9999774	0.9998727	0.9987957	0.9980413	0.9979397	0.9975653	0.9983219	0.9986438	0.9998917	0.9999727	
11.	Demand Jurisdictional Factor		0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	0.9958152	
12.	Retail Energy-Related Recoverable Costs (D)		1,471	1,336	1,471	1,491	1,543	1,473	1,536	1,533	1,475	1,552	1,494	1,480	17,855
13.	Retail Demand-Related Recoverable Costs (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
14.	Total Juris. Recoverable Costs (Lines 12 + 13)		$1,471	$1,336	$1,471	$1,491	$1,543	$1,473	$1,536	$1,533	$1,475	$1,552	$1,494	$1,480	$17,855

Notes:

(A) Line 4 x 8.7188% x 1/12. Based on ROE of 11.25% and weighted income tax rate of 38.575% (expansion factor of 1.63490).
(B) Line 4 x 2.9324% x 1/12.
(C) Line 6 is reported on Schedules 3P
(D) Line 8 is reported on Schedules 2P
(E) Line 9a x Line 10
(F) Line 9b x Line 11

* Totals on this schedule may not foot due to rounding.

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Project Title: Big Bend Unit 3 Flue Gas Desulfurization Integration

Project Description:

This project involved the integration of Big Bend Unit 3 flue gases into the Big Bend Unit 4 Flue Gas Desulfurization ("FGD") system. The integration was accomplished by installing interconnecting ductwork between Unit 3 precipitator outlet ducts and the Unit 4 FGD inlet duct. The Unit 4 FGD outlet duct was interconnected with the Unit 3 chimney via new ductwork and a new stack breaching. New ductwork, linings, isolation dampers, support steel, and stack annulus pressurization fans were procured and installed. Modifications to the materials handling systems and controls were also necessary.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2011 through December 2011, is $742,259 compared to the original projection of $742,259 representing no variance.

The actual/estimated O&M expense for the period January 2011 through December 2011 is $5,544,173 compared to the original projection of $5,154,400 resulting in an insignificant variance.

Progress Summary: The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2012 through December 2012, is expected to be $768,402.

Estimated O&M costs for the period January 2012 through December 2012 are projected to be $4,490,200.

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Project Title: Big Bend Units 1 & 2 Flue Gas Conditioning

Project Description:

The existing electrostatic precipitators were not designed for the range of fuels needed for compliance with the Clean Air Act Amendments ("CAAA"). Flue gas conditioning was required to assure operation of the generating units in accordance with applicable permits and regulations. This equipment is still required to ensure compliance with the CAAA in the event the FGD system on Units 1 & 2 is not operating.

The project involved the addition of molten sulfur unloading, storage and conveying to sulfur burners and catalytic converters where SO_2 is converted to SO_3. The control and injection system then injects this into the ductwork ahead of the electrostatic precipitators.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2011 through December 2011 is $403,377 compared to the original projection of $403,377 representing no variance.

The actual/estimated O&M expense for this project for the period January 2011 through December 2011 is $0 and did not vary from the original projection.

Progress Summary: The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2012 through December 2012 is projected to be $384,629.

There are no estimated O&M costs for the period January 2012 through December 2012.

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Project Title: Big Bend Unit 4 Continuous Emissions Monitors

Project Description:

Continuous emissions monitors (CEMs) were installed on the flue gas inlet and outlet of Big Bend Unit 4 to monitor compliance with the CAAA requirements. The monitors are capable of measuring, recording and electronically reporting SO_2, NO_x and volumetric gas flow out of the stack. The project consisted of monitors, a CEM building, the CEMs control and power cables to supply a complete system.

40 CFR Part 75 includes the general requirements for the installation, certification, operation and maintenance of CEMs and specific requirements for the monitoring of pollutants, opacity and volumetric flow. These regulations are very comprehensive and specific as to the requirements for CEMs, and in essence, they define the components needed and their configuration.

Project Accomplishment:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2011 through December 2011 is $76,381 compared to the original projection of $76,381 representing no variance.

Progress Summary: The project is complete and in-service.

Projections: Estimated depreciation plus return for the period January 2012 through December 2012 is projected to be $74,263.

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Project Title: Big Bend Unit 1 Classifier Replacement

Project Description:

The boiler modifications at Big Bend Unit 1 are part of Tampa Electric's NO_X compliance strategy for Phase II of the CAAA. The classifier replacements will optimize coal fineness by providing a uniform particle size. This finer classification, combined with the equalized distribution of coal to outlet pipes and furnaces, will enable a uniform, staged combustion. As a result, firing systems will operate at lower NO_X levels.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2011 through December 2011 is $128,734 compared to the original projection of $128,734 representing no variance.

Progress Summary: The project was placed in-service December 1998.

Projections: Estimated depreciation plus return for the period January 2012 through December 2012 is projected to be $123,674.

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Project Title: Big Bend Unit 2 Classifier Replacement

Project Description:

The boiler modifications at Big Bend Unit 2 are part of Tampa Electric's NO_X compliance strategy for Phase II of the CAAA. The classifier replacements will optimize coal fineness by providing a more uniform particle size. This finer classification, combined with the equalized distribution of coal to outlet pipes and furnaces, will enable a uniform, staged combustion. As a result, firing systems will operate at lower NO_X levels.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2011 through December 2011 is $93,421 compared to the original projection of $93,421 representing no variance.

Progress Summary: The project was placed in-service May 1998.

Projections: Estimated depreciation plus return for the period January 2012 through December 2012 is projected to be $89,861.

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Project Title: Big Bend Units 1 & 2 FGD

Project Description:

The Big Bend Units 1 & 2 FGD system consists of equipment capable of removing SO_2 from the flue gas generated by the combustion of coal. The FGD was installed in order to comply with Phase II of the CAAA. Compliance with Phase II is required by January 1, 2000. The CAAA impose SO_2 emission limits on existing steam electric units with an output capacity of greater than 25 megawatts and all new utility units. Tampa Electric conducted an exhaustive analysis of options to comply with Phase II of the CAAA that culminated in the selection of the FGD project to serve Big Bend Units 1 & 2.

In Docket No. 980693-EI, Order No. PSC-99-0075-FOF-EI, issued January 11, 1999, the Commission found that the FGD project was the most cost-effective alternative for compliance with the SO_2 requirements of Phase II of the CAAA.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2011 through December 2011 is $8,682,949 compared to the original projection of $8,896,117 representing an insignificant variance.

The actual/estimated O&M expense for the period January 2011 through December 2011 is $7,629,441 as compared to the original estimate of $7,791,300 representing an insignificant variance.

Progress Summary: The project was placed in-service in December 1999.

Projections: Estimated depreciation plus return for the period January 2012 through December 2012 is expected to be $8,815,500.

Estimated O&M costs for the period January 2012 through December 2012 are projected to be $8,835,100.

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Project Title: Big Bend Section 114 Mercury Testing Platform

Project Description:

The Mercury Emissions Information Collection Effort is mandated by the EPA. The EPA asserts that Section 114 of the CAAA grants to the EPA the authority to request the collection of information necessary for it to study whether it is appropriate and necessary to develop performance or emission standards for electric utility steam generating units.

In a letter dated November 25, 1998, Tampa Electric was notified by the EPA that, pursuant to Section 114 of the CAAA, the company was required to periodically sample and analyze coal shipments for mercury and chlorine content during the period January 1, 1999 through December 31, 1999.

In addition to coal sampling, stack testing and analyses are also required. Tampa Electric received a second letter from EPA, dated March 11, 1999, requiring Tampa Electric to perform specialized mercury testing of the inlet and outlet of the last emission control device installed for Big Bend Units 1, 2 or 3, and Polk Unit 1 as part of the mercury data collection. Part of the cost incurred to perform the stack testing is due to the need to construct special test facilities at the Big Bend stack testing location to meet EPA's testing requirements.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2011 through December 2011, is $13,022 compared to the original projection of $13,022 representing no variance.

Progress Summary: The project was placed in-service in December 1999 and was completed in May 2000.

Projections: Estimated depreciation plus return for the period January 2012 through December 2012 is expected to be $12,739.

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Project Title: Big Bend FGD Optimization and Utilization

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric was required to optimize the SO_2 removal efficiency and operations of the Big Bend Units 1, 2 and 3 FGD systems. Tampa Electric performed activities in three key areas to improve the performance and reliability of the Big Bend Units 1, 2 and 3 FGD systems. The majority of the improvements required on the Unit 3 tower module included the tower piping, nozzle and internal improvements, ductwork improvements, electrical system reliability improvements, tower control improvements, dibasic acid system improvements, booster fan reliability, absorber system improvements, quencher system improvements, and tower demister improvements. Big Bend Units 1 and 2 FGD system improvements included additional preventative maintenance, oxidation air control improvements, and tower water, air reagent and start-up piping upgrades. In order to ensure reliability of the FGD systems, improvements to the common limestone supply, gypsum de-watering stack reliability and wastewater treatment plant were also being performed.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2011 through December 2011 is $2,417,303 compared to the original projection of $2,417,303 representing no variance.

Progress Summary: The project was placed in-service in January 2002.

Projections: Estimated depreciation plus return for the period January 2012 through December 2012 is expected to be $2,359,083.

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Project Title: Big Bend PM Minimization and Monitoring

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to develop a Best Operational Practices ("BOP") study to minimize emissions from each electrostatic precipitator ("ESP") at Big Bend, as well as perform a best available control technology ("BACT") analysis for the upgrade of each existing ESP. The company is also required to install and operate particulate matter continuous emission monitors on Big Bend Units 1, 2 and 3 FGD systems. Tampa Electric has identified improvements that are necessary to optimize ESP performance such as modifications to the turning vanes and precipitator distribution plates, and upgrades to the controls and software system of the precipitators. Tampa Electric has incurred costs associated with the recommendations of the BOP study and the BACT analysis in 2001 and will continue to experience O&M and capital expenditures during 2002 and beyond.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2011 through December 2011 is $1,062,800 as compared to the original projection of $1,081,441 resulting in an insignificant variance.

The actual/estimated O&M expense the period January 2011 through December 2011 is $279,413 as compared to the original projection of $479,200 resulting in a variance of 42 percent. The variance is driven by the reduction in maintenance costs associated with implementing best operating practices that have been developed over time.

Progress Summary: This project was placed in-service July 2005.

Projections: Estimated depreciation plus return for the period January 2012 through December 2012 is expected to be $1,076,352.

Estimated O&M costs for the period January 2012 through December 2012 are projected to be $390,400.

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Project Title: Big Bend NO_x Emissions Reduction

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to spend up to $3 million with the goal to reduce NO_x emissions at Big Bend Station. The Consent Decree requires that by December 31, 2002, the company must achieve at least a 30 percent reduction beyond 1998 levels for Big Bend Units 1 and 2 and at least a 15 percent reduction in NO_x emissions from Big Bend Unit 3. Tampa Electric has identified projects that are the first steps to decrease NO_x emissions in these units such as burner and windbox modifications and the installation of a neural network system on each of the Big Bend units.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2011 through December 2011 is $781,211 as compared to the original projection of $791,631 representing an insignificant variance.

The actual/estimated O&M expense the period January 2011 through December 2011 is $379,930 as compared to the original projection of $396,000 resulting in an insignificant variance.

Progress Summary: The project was placed in-service January 2006.

Projections: Estimated depreciation plus return for the period January 2012 through December 2012 is expected to be $769,550.

Estimated O&M costs for the period January 2012 through December 2012 are projected to be $395,000.

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Project Title: Big Bend Fuel Oil Tank No. 1 Upgrade

Project Description:

The Big Bend Fuel Oil Tank No. 1 Upgrade is a 500,000 gallon field-erected fuel storage tank that is required to meet the requirements of FDEP Rule 62-762 as an existing field-erected above ground storage tank containing a regulated pollutant (diesel fuel). The rule required various modifications and a complete internal inspection by the end of 1999.

The scope of work for this project included cleaning and inspecting the tank in accordance with API 653 specifications, coating the internal floor plus 30 inches up the tank wall, installing an AEI Segundo bottom to the tank as well as installing a leak detection system, installing a spill containment for piping fittings and valves surrounding the tank, installing a new truck unloading facility and spill containment for the truck unloading facility, installing level instrumentation for overfill protection, installing secondary containment for below ground piping or reroute to above ground, and conducting a tank closure assessment.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2011 through December 2011 is $51,572 compared to the original projection of $51,572 representing no variance.

Progress Summary: The project was placed in-service October 1998.

Projections: Estimated depreciation plus return for the period January 2012 through December 2012 is projected to be $50,065.

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Project Title: Big Bend Fuel Oil Tank No. 2 Upgrade

Project Description:

The Big Bend Fuel Oil Tank No. 2 Upgrade is a 4,200,000 gallon field-erected fuel storage tank that is required to meet the requirements of FDEP Rule 62-762 as an existing field-erected above ground storage tank containing a regulated pollutant (diesel fuel). The rule required various modifications and a complete internal inspection by the end of 1999.

The scope of work for this project included cleaning and inspecting the tank in accordance with API 653 specifications, coating the internal floor plus 30 inches up the tank wall, installing an AEI Segundo bottom to the tank as well as installing a leak detection system, installing a spill containment for piping fittings and valves surrounding the tank, installing a new truck unloading facility and spill containment for the truck unloading facility, installing level instrumentation for overfill protection, installing secondary containment for below ground piping or reroute to above ground, and conducting a tank closure assessment.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2011 through December 2011 is $84,824 compared to the original projection of $84,824 representing no variance.

Progress Summary: The project was placed in-service December 1998.

Projections: Estimated depreciation plus return for the period January 2012 through December 2012 is projected to be $82,344.

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Project Title: Phillips Oil Tank No. 1 Upgrade

Project Description:

The Phillips Oil Tank No. 1 Upgrade is a 1,300,000 gallon field-erected fuel storage tank that is required to meet the requirements of FDEP Rule 62-762 as an existing field-erected above ground storage tank containing a regulated pollutant (diesel fuel). The rule required various modifications and a complete internal inspection by the end of 1999.

The scope of work for this project included cleaning and inspecting the tank in accordance with API 653 specifications, coating the internal floor plus 30 inches up the tank wall, installing a spill containment for piping fittings and valves surrounding the tank, installing level instrumentation for overfill protection, installing secondary containment for below ground piping or reroute to above ground, and conducting a tank closure assessment.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2011 through December 2011, is $5,461 compared to the original projection of $5,461 representing no variance.

Progress Summary: The project is complete and was placed in-service October 1998.

Projections: Estimated depreciation plus return for the period January 2012 through December 2012 is projected to be $5,267.

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Project Title: Phillips Oil Tank No. 4 Upgrade

Project Description:

The Phillips Oil Tank No. 4 Upgrade is a 57,000 gallon field-erected fuel storage tank that is required to meet the requirements of FDEP Rule 62-762 as an existing field-erected above ground storage tank containing a regulated pollutant (diesel fuel). The rule required various modifications and a complete internal inspection by the end of 1999.

The scope of work for this project included cleaning and inspecting the tank in accordance with API 653 specifications, coating the internal floor plus 30 inches up the tank wall, installing a spill containment for piping fittings and valves surrounding the tank, installing level instrumentation for overfill protection, installing secondary containment for below ground piping or reroute to above ground, and conducting a tank closure assessment.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2011 through December 2011 is $8,584 compared to the original projection of $8,584 representing no variance.

Progress Summary: The project is complete and was placed in-service October 1998.

Projections: Estimated depreciation plus return for the period January 2012 through December 2012 is projected to be $8,267.

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Project Title: SO_2 Emission Allowances

Project Description:

The acid rain control title of the CAAA sets forth a comprehensive regulatory mechanism designed to control acid rain by limiting sulfur dioxide emissions by electric utilities. The CAAA requires reductions in SO_2 emissions in two phases. Phase I began on January 1, 1995 and applies to 110 mostly coal-fired utility plants containing about 260 generating units. These plants are owned by some 40 jurisdictional utility systems that are expected to reduce annual SO_2 emissions by as much as 4.5 million tons. Phase II began on January 1, 2000, and applies to virtually all existing steam-electric generating utility units with capacity exceeding 25 megawatts and to new generating utility units of any size. The EPA issues to the owners of generating units allowances (defined as an authorization to emit, during or after a specified calendar year, one ton of SO_2) equal to the number of tons of SO_2 emissions authorized by the CAAA. EPA does not assess a charge for the allowances it awards.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated return on average net working capital for the period January 2011 through December 2011 is ($4,556) compared to the original projection of ($4,530) representing an insignificant variance.

The actual/estimated O&M for the period January 2011 through December 2011 is $26,956 compared to the original projection of $601,313 representing a variance of 96 percent. The variance is driven by less cogeneration purchases than expected and the application of a lower rate than originally projected.

Progress Summary: SO_2 emission allowances are being used by Tampa Electric to meet compliance standards for Phase I of the CAAA.

Project Projections: Estimated return on average net working capital for the period January 2012 through December 2011 is projected to be ($4,391).

Estimated O&M costs for the period January 2012 through December 2012 are projected to be $22,262.

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Project Title: National Pollutant Discharge Elimination System ("NPDES") Annual Surveillance Fees

Project Description:

Chapter 62-4.052, Florida Administrative Code ("F. A. C."), implements the annual regulatory program and surveillance fees for wastewater permits. These fees are in addition to the application fees described in Rule 62-4.050, F. A. C. Tampa Electric's Big Bend, Hookers Point, Polk Power and Gannon Stations are affected by this rule.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M expense for the period January 2011 through December 2011 is $34,500 compared to the original projection of $34,500 representing no variance.

Progress Summary: NPDES Surveillance fees are paid annually for the prior year.

Projections: Estimated O&M costs for the period January 2012 through December 2012 are projected to be $34,500.

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Project Title: Gannon Thermal Discharge Study

Project Description:

This project is a direct requirement from the FDEP in conjunction with the renewal of Tampa Electric's Industrial Wastewater Facility Permit under the provisions of Chapter 403, Florida Statutes, and applicable rules of the Florida Administrative Code, which constitute authorization for the company's Gannon Station facility to discharge to waters of the State under the NPDES. The FDEP permit is Permit No. FL0000809. Specifically, Tampa Electric is required to perform a 316(a) determination for Gannon Station to ensure the protection and propagation of a balanced, indigenous population of shellfish, fish and wildlife with in the primary area of study. The project will have two facets: 1) develop the plan of study and identify the thermal plume, and 2) implement the plan of study through appropriate sampling to make the determination if any adverse impacts are occurring.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M expense for the period January 2011 through December 2011 is $73,495 compared to the original projection of $30,000, which represents a variance of 145 percent. The variance is due to an evaluation to determine a method of how to lower cooling water discharge temperatures.

Progress Summary: This project was approved by the Commission in Docket No. 010593-EI on September 4, 2001.

Projections: Estimated O&M costs for the period January 2012 through December 2012 are projected to be $20,000.

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Project Title: Polk NO_x Emissions Reduction

Project Description:

This project is designed to meet a lower NO_x emissions limit established by the FDEP for Polk Unit 1 by July 1, 2005. The lower limit of 15 parts per million by volume dry basis at 15 percent O_2 is specified in FDEP Permit No. PSD-FL-194F issued February 5, 2002. The project will consist of two phases: 1) the humidification of syngas through the installation of a syngas saturator; and 2) the modification of controls and the installation of additional guide vanes to the diluent nitrogen compressor.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2011 through December 2011 is $189,422 as compared to the original projection of $189,422 representing no variance.

The actual/estimated O&M for the period January 2011 through December 2011 is $(20,284) compared to the original projection of $50,000, which represents a variance of 141 percent. The variance is due to the sale of NO_x emissions which offset the cost of maintenance activities.

Progress Summary: The project was placed in-service January 2005.

Project Projections: Estimated depreciation plus return for the period January 2012 through December 2012 is projected to be $183,237.

Estimated O&M costs for the period January 2012 through December 2012 are projected to be $35,000.

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Project Title: Bayside SCR Consumables

Project Description:

This project is necessary to achieve the NO_x emissions limit of 3.5 parts per million established by the FDEP Consent Final Judgment and the EPA Consent Decree for the natural gas-fired Bayside Power Station. To achieve this NO_x limit, the installation of selective catalytic reduction (SCR) systems is required. An SCR system requires consumable goods – primarily anhydrous ammonia – to be injected into the catalyst bed in order to achieve the required NO_x emissions limit. Principally, the project is designed to capture the cost of consumable goods necessary to operate the SCR systems.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M expense for the period January 2011 through December 2011 is $102,108 compared to the original projection of $115,200 resulting in an insignificant variance.

Progress Summary: This project was approved by the Commission in Docket No. 021255-EI, Order No. PSC-03-0469-PAA-EI, issued April 4, 2003. As an O&M project, expenses are ongoing annually.

Projections: Estimated O&M costs for the period January 2012 through December 2012 are projected to be $106,400.

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Project Title: Big Bend Unit 4 Separated Overfire Air ("SOFA")

Project Description:

This project is necessary to assist in achieving the NO_x emissions limit established by the FDEP Consent Final Judgment and the EPA Consent Decree for Big Bend Unit 4. A SOFA system stages secondary combustion air to prevent NO_x formation that would otherwise require removal by post-combustion technology. In-furnace combustion control through a SOFA system is the most cost-effective means to reduce NO_x emissions prior to the application of these technologies. Costs associated with the SOFA system will entail capital expenditures for equipment installation and subsequent annual maintenance.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2011 through December 2011 is $310,809 compared to the original projection of $310,809 representing no variance.

The actual/estimated O&M for the period January 2011 through December 2011 is $0 compared to the original projection of $0 representing no variance.

Progress Summary: The project was placed in-service November 2004.

Projections: Estimated depreciation plus return for the period January 2012 through December 2012 is projected to be $303,655.

There are no estimated O&M costs for the period January 2012 through December 2012.

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Project Title: Big Bend Unit 1 Pre-SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2012 through 2012. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal which will necessitate the installation of cost-effective SCR technology on the generating units to meet NO_x emissions requirements. Therefore, this project is a necessary precursor to an SCR system designed to reduce inlet NO_x concentrations to the SCR system thereby mitigating overall capital and O&M costs. The Big Bend Unit 1 Pre-SCR technologies include a neural network system, secondary air controls and windbox modifications.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2011 through December 2011 is $218,293 compared to the original projection of $261,143 representing a variance 16 percent. The variance is due to the retirement of the neural network component related to Big Bend Pre-SCR program and the resultant decrease of the construction work in progress.

The actual/estimated O&M for the period January 2011 through December 2011 is $249 compared to the original projection of $0 representing an insignificant variance.

Progress Summary: This project was approved by the Commission in Docket No. 040750-EI, Order No. PSC-04-1080-CO-EI, issued November 4, 2004.

Projections: Estimated depreciation plus return for the period January 2012 through December 2012 is projected to be $211,950.

There are no estimated O&M costs for the period January 2012 through December 2012.

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Project Title: Big Bend Unit 2 Pre-SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2012through 2012. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal which will necessitate the installation of cost-effective SCR technology on the generating units to meet NO_x emissions requirements. Therefore, this project is a necessary precursor to an SCR system designed to reduce inlet NO_x concentrations to the SCR system thereby mitigating overall capital and O&M costs. The Big Bend Unit 2 Pre-SCR technologies include secondary air controls and windbox modifications.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2011 through December 2011 is $207,873 compared to the original projection of $207,873 representing no variance.

The actual/estimated O&M for the period January 2011 through December 2011 is $0 compared to the original projection of $0 representing no variance.

Progress Summary: This project was approved by the Commission in Docket No. 040750-EI, Order No. PSC-04-1080-CO-EI, issued November 4, 2004.

Projections: Estimated depreciation plus return for the period January 2012 through December 2012 is projected to be $202,159.

There are no estimated O&M costs for the period January 2012 through December 2012.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2012 through December 2012
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 3 Pre-SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2012 through 2012. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal, which will necessitate the installation of cost-effective SCR technology on the generating units to meet NO_x emissions requirements. Therefore, this project is a necessary precursor to an SCR system designed to reduce inlet NO_x concentrations to the SCR system thereby mitigating overall capital and O&M costs. The Big Bend Unit 3 Pre-SCR technologies include a neutral network system, secondary air controls, windbox modifications and primary coal/air flow controls.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2011 through December 2011 is $358,814 compared to the original projection of $358,814, resulting in no variance.

The actual/estimated O&M for the period January 2011 through December 2011 is $200 compared to the original projection of $0 resulting in no variance.

Progress Summary: This project was approved by the Commission in Docket No. 040750-EI, Order No. PSC-04-1080-CO-EI, issued November 4, 2004.

Projections: Estimated depreciation plus return for the period January 2012 through December 2012 is projected to be $350,697.

There are no estimated O&M costs for the period January 2012 through December 2012.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2012 through December 2012
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Clean Water Act Section 316(b) Phase II Study

Project Description:

This project is a direct requirement from the EPA to reduce impingement and entrainment of aquatic organisms related to the withdrawal of waters for cooling purposes through cooling water intake structures. The Phase II Rule requires that power plants meeting certain criteria to comply with national performance standards for impingement and entrainment. Accordingly, Tampa Electric must develop its compliance strategies for its H. L. Culbreath Bayside Power and the Big Bend Power Stations and then submit these strategies for approval through a Comprehensive Demonstration Study to the FDEP.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M for the period January 2011 through December 2011 is $54,260 compared to the original projection of $60,000 resulting in an insignificant variance.

Progress Summary: This project was approved by the Commission in Docket No. 041300-EI, Order No. PSC-05-0164-PAA-EI, issued February 10, 2005.

Projections: Estimated O&M costs for the period January 2012 through December 2012 are projected to be $30,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2012 through December 2012
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 1 SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2012 through 2012. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal, which will necessitate the installation of cost-effective SCR technology on the generating units to meet NO_x emissions requirements. This project is associated with the installation of an SCR system on Big Bend Unit 1 and is scheduled to go in-service April 2010.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2011 through December 2011 is $11,720,715 compared to the original projection of $11,823,188 resulting in an insignificant variance.

The actual/estimated O&M for the period January 2011 through December 2011 is $1,992,957 compared to the original projection of $958,900 resulting in a variance of 108 percent. This variance is due to an increase in maintenance expenses associated with the higher than projected contractor and material costs. Additionally, ammonia usage was greater than projected.

Progress Summary: This project was approved by the Commission in Docket No. 041376-EI, Order No. PSC-05-0616-CO-EI, issued June 3, 2005.

Projections: Estimated depreciation plus return for the period January 2012 through December 2012 is projected to be $11,474,749.

Estimated O&M costs for the period January 2012 through December 2012 are projected to be $2,466,489.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2012 through December 2012
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 2 SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2012 through 2012. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal, which will necessitate the installation of cost-effective SCR technology on the generating units to meet NO_x emissions requirements. This project is associated with the installation of an SCR system on Big Bend Unit 2 and is scheduled to go in-service September 2009.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2011 through December 2011 is $12,562,769 compared to the original projection of $12,522,896, resulting an insignificant variance.

The actual/estimated O&M for the period January 2011 through December 2011 is $1,280,394 compared to the original projection of $1,728,400 representing a variance of 26 percent. The variance is due to consumption of ammonia being less than projected.

Progress Summary: This project was approved by the Commission in Docket No. 041376-EI, Order No. PSC-05-0616-CO-EI, issued June 3, 2005.

Projections: Estimated depreciation plus return for the period January 2012 through December 2012 is projected to be $12,505,318.

Estimated O&M costs for the period January 2012 through December 2012 are projected to be $2,536,432.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2012 through December 2012
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 3 SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2012 through 2012. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal which will necessitate the installation of cost-effective SCR technology on the generating units to meet NO_x emissions requirements. This project is associated with the installation of an SCR system on Big Bend Unit 3 and is scheduled to go in-service July 2008.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2011 through December 2011 is $10,430,446 compared to the original projection of $10,323,816 resulting in an insignificant variance.

The actual/estimated O&M for the period January 2011 through December 2011 is $1,856,640 compared to the original projection of $1,695,400 resulting in an insignificant variance.

Progress Summary: This project was approved by the Commission in Docket No. 041376-EI, Order No. PSC-05-0616-CO-EI, issued June 3, 2005.

Projections: Estimated depreciation plus return for the period January 2012 through December 2012 is projected to be $10,258,438.

Estimated O&M costs for the period January 2012 through December 2012 are projected to be $1,513,033.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2012 through December 2012
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Unit 4 SCR

Project Description:

In order to meet the requirements of the FDEP Consent Final Judgment and the EPA Consent Decree, Tampa Electric is required to make additional reductions of NO_x emissions at Big Bend Station on a per unit basis at prescribed times from 2012 through 2012. Based on a comprehensive study, Tampa Electric has declared the future fuel for Big Bend Station to be coal which will necessitate the installation of cost-effective SCR technology on the generating units to meet NO_x emissions requirements. This project is associated with the installation of an SCR system on Big Bend Unit 4 and is scheduled to go in-service May 2007.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2011 through December 2011 is $7,950,899 compared to the original projection of $7,722,172 resulting in an insignificant variance.

The actual/estimated O&M for the period January 2011 through December 2011 is $1,441,134 compared to the original projection of $758,200 representing a variance of 90 percent. The variance is due to maintenance costs being greater than projected as well as an increase in the usage of ammonia.

Progress Summary: This project went in to service in May 2007.

Projections: Estimated depreciation plus return for the period January 2012 through December 2012 is projected to be $7,799,065.

Estimated O&M costs for the period January 2012 through December 2012 are projected to be $998,269.

<u>Tampa Electric Company</u>
Environmental Cost Recovery Clause
January 2012 through December 2012
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Arsenic Groundwater Standard Program

Project Description:
The Arsenic Groundwater Standard Program that is required by the Environmental Protection Agency and the Department of Environmental Protection became effective January 1, 2005. It requires regulated entities of the State of Florida to monitor the drinking water and groundwater Maximum Contaminant Level ("MCL") for arsenic under the federal rule known as the Safe Drinking Water Act.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M for the period January 2011 through December 2011 is $119,369 compared to the original projection of $170,000 resulting in a variance of 30 percent. The variance is due to FDEP delay in approval of activity associated with projected work.

Progress Summary: In Docket No. 050683-EI, Order No. PSC-06-0138-PAA-EI, issued February 23, 2006, the Commission granted Tampa Electric cost recovery approval for prudent costs associated with this project.

Projections: Estimated O&M costs for the period January 2012 through December 2012 are projected to be $667,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2012 through December 2012
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Big Bend Flue Gas Desulfurization ("FGD") System Reliability

Project Description:
The Big Bend FGD Reliability project is necessary to maintain the FGD system operations that are required by the Consent Decree. Tampa Electric is required to operate the FGD systems at Big Bend Station whenever coal is combusted in the units with few exceptions. The compliance dates for the strictest operational characteristics are January 1, 2011 for Big Bend Unit 3 and January 1, 2013 for Big Bend Units 1 and 2.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2011 through December 2011 is $1,732,791 compared to the original projection of $1,959,594 resulting in variance of 12 percent. The variance is due to the overall expenditures for the project now estimated to be less for the year. Additionally, the original expenditures were projected to occur throughout the year but will now be occurring during the latter part of the year. This timing change on expenditures lowered the original monthly CWIP amounts and thus the monthly return on average net investment amounts thereby creating the modest annual estimated variance.

Progress Summary: In Docket No. 050598-EI, Order No. PSC-06-0602-PAA-EI, issued July 10, 2006, the Commission granted cost recovery approval for prudent costs associated with this project.

Projections: Estimated depreciation plus return for the period January 2012 through December 2012 is projected to be $3,473,539.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2012 through December 2012
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Clean Air Mercury Rule ("CAMR")

Project Description:
The EPA established standards of performance for mercury for new and existing coal-fired electric utility steam generating units as defined in the federal Clean Air Act, known as the Clean Air Mercury Rule ("CAMR"). CAMR was designed to permanently cap mercury emissions nation-wide in two phases ending in 2018. On February 8, 2008 the Washington, D.C. Circuit Court vacated EPA's rule removing power plants from the Clean Air Act list of regulated sources of hazardous air pollutants under section 112 and vacated the Clean Air Mercury Rule. However, on May 3, 2011 EPA published a new proposed rule for mercury and other hazardous air pollutants according to the National Emissions Standards for Hazardous Air Pollutants section of the Clean Air Act. The proposed rule calls for mercury monitoring requirements comparable to CAMR by 2014. Tampa Electric must conduct extensive emissions testing and engineering studies at Big Bend Station and Polk Power Station to determine what actions are required to meet the proposed standards.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated depreciation plus return for the period January 2011 through December 2011 is $164,511 compared to the original projection of $167,154 resulting in an insignificant variance.

The actual/estimated O&M for the period January 2011 through December 2011 is $26,839 compared to the original projection of $8,000 resulting in a variance of 236 percent. The variance is due to the EPA Information Collection Request requiring extensive air emission testing at Polk Power Station and Big Bend Station. EPA is collecting data in support of Clean Air Act National Emission Standards for Hazardous Air Pollutant rulemaking that is under way.

Progress Summary: A petition was filed on August 30, 2006 seeking Commission approval of cost recovery through the ECRC for the new CAMR program.

Projections: Estimated depreciation plus return for the period January 2012 through December 2012 is projected to be $166,916.

Estimated O&M costs for the period January 2012 through December 2012 are projected to be $24,000.

Tampa Electric Company
Environmental Cost Recovery Clause
January 2012 through December 2012
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: Greenhouse Gas Reduction Program

Project Description:
On September 22, 2009, the EPA enacted a new rule for reporting Greenhouse Gas ("GHG") emissions from large sources and suppliers effective January 1, 2010 in preparation for the first annual GHG report, due March 31, 2011. The new rule is intended to collect accurate and timely emissions data to inform future policy decisions as set forth in the final rule for GHG emission reporting pursuant to the Florida Climate Protection Act, Chapter 403.44 of the Florida Statutes and the docket EPA-HQ-OAR2008-0508-054. The nationwide GHG emissions reduction rule will impact Tampa Electric's generation fleet, components of its transmission and distribution system as well as company service vehicles. According to the rule, the company must begin collecting greenhouse gas emissions data effective January 1, 2010 to establish a baseline inventory to report to the EPA.

Project Accomplishments:

Fiscal Expenditures: The actual/estimated O&M for the period January 2011 through December 2011 is $42,958 compared to the original projection of $56,100 resulting in a variance of 23 percent. The variance is due to the project taking less time than originally expected.

Progress Summary: Cost recovery was approved in Docket No. 090508-EI, Order No. PSC-10-0157-PAA-EI, issued March 22, 2010.

Projections: Estimated O&M costs for the period January 2012 through December 2012 are projected to be $40,000.

Form 42 - 6P

Tampa Electric Company

Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2012 to December 2012

Rate Class	(1) Average 12 CP Load Factor at Meter (%)	(2) Projected Sales at Meter (MWh)	(3) Effective Sales at Secondary Level (MWh)	(4) Projected Avg 12 CP at Meter (MW)	(5) Demand Loss Expansion Factor	(6) Energy Loss Expansion Factor	(7) Projected Sales at Generation (MWh)	(8) Projected Avg 12 CP at Generation (MW)	(9) Percentage of MWh Sales at Generation (%)	(10) Percentage of 12 CP Demand at Generation (%)	(11) 12 CP & 25% Allocation Factor (%)
RS	53.82%	8,889,736	8,889,736	1,886	1.08084	1.05540	9,382,208	2,038	46.84%	57.09%	54.53%
GS, TS	59.28%	1,041,638	1,041,638	201	1.08084	1.05538	1,099,328	217	5.49%	6.08%	5.93%
GSD, SBF	80.91%	7,875,219	7,862,368	1,111	1.07633	1.05161	8,281,683	1,196	41.34%	33.50%	35.46%
IS	102.46%	1,023,749	1,006,067	114	1.03157	1.01880	1,042,990	118	5.21%	3.31%	3.78%
LS1	2255.01%	213,911	213,911	1	1.08084	1.05540	225,761	1	1.13%	0.03%	0.30%
TOTAL *		19,044,253	19,013,720	3,313			20,031,970	3,570	100.00%	100.00%	100.00%

Notes:
(1) Average 12 CP load factor based on 2011 projected calendar data
(2) Projected MWh sales for the period January 2012 to December 2012
(3) Effective sales at secondary level for the period January 2012 to December 2012.
(4) Column 2 / (Column 1 x 8760)
(5) Based on 2011 proposed demand losses.
(6) Based on 2011 projected energy losses.
(7) Column 2 x Column 6
(8) Column 4 x Column 5
(9) Column 7 / Total Column 7
(10) Column 8 / Total Column 8
(11) Column 9 x 0.25 + Column 10 x 0.75

* Totals on this schedule may not foot due to rounding

DOCKET NO. 110007-EI
ECRC 2012 PROJECTION FILING
EXHIBIT NO. HTB-3
DOCUMENT NO. 6

Form 42 - 7P

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2012 to December 2012

Rate Class	(1) Percentage of MWh Sales at Generation (%)	(2) 12 CP & 25% Allocation Factor (%)	(3) Energy-Related Costs ($)	(4) Demand-Related Costs ($)	(5) Total Environmental Costs ($)	(6) Projected Sales at Meter (MWh)	(7) Effective Sales at Secondary Level (MWh)	**(8) Environmental Cost Recovery Factors (¢/kWh)**
RS	46.84%	54.53%	40,421,573	494,577	40,916,150	8,889,736	8,889,736	**0.460**
GS, TS	5.49%	5.93%	4,736,259	53,805	4,790,064	1,041,638	1,041,638	**0.460**
GSD, SBF	41.34%	35.46%	35,680,157	321,641	36,001,798	7,875,219	7,862,368	
Secondary								**0.458**
Primary								**0.453**
Transmission								**0.449**
IS	5.21%	3.78%	4,493,537	34,324	4,527,861	1,023,749	1,006,067	
Secondary								**0.450**
Primary								**0.446**
Transmission								**0.441**
LS1	1.13%	0.30%	972,651	2,760	975,411	213,911	213,911	**0.456**
TOTAL *	100.00%	100.00%	86,304,177	907,039	87,211,216	19,044,253	19,013,720	**0.459**

* Totals on this schedule may not foot due to rounding

Notes:
(1) From Form 42-6P, Column 9
(2) From Form 42-6P, Column 11
(3) Column 1 x Total Energy Jurisdictional Dollars from Form 42-1P, line 5
(4) Column 2 x Total Demand Jurisdictional Dollars from Form 42-1P, line 5
(5) Column 3 + Column 4
(6) From Form 42-6P, Column 2
(7) From Form 42-6P, Column 3
(8) Column 5 / Column 7 x 100

DOCKET NO. 110007-EI
ECRC 2012 PROJECTION FILIN(
EXHIBIT NO. HTB-3
DOCUMENT NO. 7

Form 42 - 8P

Tampa Electric Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 to December 2012

Calculation of Revenue Requirement Rate of Return
(In Dollars)

	(1) Jurisdictional Rate Base 2009 Test Year ($000)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %
Long Term Debt	$ 1,384,999	40.29%	6.80%	2.7397%
Short Term Debt	7,905	0.23%	2.75%	0.0063%
Preferred Stock	0	0.00%	0.00%	0.0000%
Customer Deposits	99,502	2.89%	6.07%	0.1754%
Common Equity	1,632,612	47.49%	11.25%	5.3426%
Deferred ITC - Weighted Cost	8,964	0.26%	9.19%	0.0239%
Accumulated Deferred Income Taxes & Zero Cost ITCs	303,629	8.83%	0.00%	0.0000%
Total	$ 3,437,611	100.00%		8.2879%

ITC split between Debt and Equity:

Long Term Debt	$ 1,384,999	Long Term Debt	45.78%
Short Term Debt	7,905	Short Term Debt	0.26%
Equity - Preferred	0	Equity - Preferred	0.00%
Equity - Common	1,632,612	Equity - Common	53.96%
Total	$ 3,025,516	Total	100.00%

Deferred ITC - Weighted Cost:

Debt = .0239% * 46.04%	0.0110%
Equity = .0239% * 53.96%	0.0129%
Weighted Cost	0.0239%

Total Equity Cost Rate:

Preferred Stock	0.0000%
Common Equity	5.3426%
Deferred ITC - Weighted Cost	0.0129%
	5.3555%
Times Tax Multiplier	1.628002
Total Equity Component	8.7188%

Total Debt Cost Rate:

Long Term Debt	2.7397%
Short Term Debt	0.0063%
Customer Deposits	0.1754%
Deferred ITC - Weighted Cost	0.0110%
Total Debt Component	2.9324%

Notes:
Column (1) - From Order No. PSC-09-0571-FOF-EI
Column (2) - Column (1) / Total Column (1)
Column (3) - From Order No. PSC-09-0571-FOF-EI
Column (4) - Column (2) x Column (3)

Florida Department of Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Rick Scott
Governor

Jennifer Carroll
Lt. Governor

Herschel Vinyard, Jr.
Secretary

NOTICE OF PERMIT

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

In the Matter of an
Application for Permit by:

Gulf Power Company
James O. Vick
One Energy Place
Pensacola, Florida 32520

PA File No. FL0002275-013-IW1S
Escambia County
Crist Electric Generating Plant
NPDES Permit No. FL0002275

Enclosed is Permit Number FL0002275 to operate the Crist Electric Generating Plant, issued under Chapter 403, Florida Statutes.

Monitoring requirements under this permit are effective on the first day of the second month following permit issuance. Until such time, the permittee shall continue to monitor and report in accordance with previously effective permit requirements, if any.

Any party to this order (permit) has the right to seek judicial review of the permit action under Section 120.68, Florida Statutes, by the filing of a notice of appeal under Rules 9.110 and 9.190, Florida Rules of Appellate Procedure, with the Clerk of the Department of Environmental Protection, Office of General Counsel, 3900 Commonwealth Boulevard, Mail Station 35, Tallahassee, Florida 32399-3000, and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate district court of appeal. The notice of appeal must be filed within 30 days from the date when this document is filed with the Clerk of the Department.

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

Director
Division of Water Resource Management
2600 Blair Stone Road
Tallahassee, FL 32399-2400
(850) 245-8336

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI EXHIBIT 34
PARTY GULF POWER COMPANY (DIRECT)
DESCRIPTION J. O. VICK (JOV-1)
DATE 11/01/11

CERTIFICATE OF SERVICE

The undersigned duly designated deputy clerk hereby certifies that this INTENT TO ISSUE and all copies were mailed by certified mail before the close of business on 01-26-2011 to the listed persons.

[Clerk Stamp]

FILING AND ACKNOWLEDGMENT

FILED, on this date, under section 120.52(7), Florida Statutes, with the designated Department Clerk, receipt of which is hereby acknowledged.

Shirley Shields 01-26-2011
Clerk Date

Certified copies furnished to:
- Mark Nuhfer, NPDES Permitting Section, EPA Region 4, Atlanta, GA
- Chairman, Board of Escambia County Commissioners
- Susan Kennedy, Q.E.P., Gulf Power Company
- Mike Markey, Gulf Power Company

Copies furnished by intradepartmental mail to:
- David Morres, P.E., DEP Pensacola
- Bill Armstrong, P.E., DEP Pensacola
- Kim Allen, DEP Pensacola
- Dawn Templin, P.E. DEP Pensacola
- Nancy Ross, DEP Tallahassee
- Michael Tanski, DEP Tallahassee
- Justin Wolfe, Esq., DEP Tallahassee

STATE OF FLORIDA
INDUSTRIAL WASTEWATER FACILITY PERMIT

PERMIT NUMBER:	FL0002275 (Major)
FILE NUMBER:	FL0002275-013-IW1S
ISSUANCE DATE:	January 28, 2011
EXPIRATION DATE:	January 27, 2016

PERMITTEE:
Gulf Power Company

RESPONSIBLE OFFICIAL:
James O. Vick
One Energy Place
Pensacola, Florida 32520
(850) 444-6429

FACILITY:

Crist Electric Generating Plant
End of Pate Road, off Ten Mile Road
Pensacola, FL 32414
Escambia County
Latitude: 30° 33' 54.57" N Longitude: 87° 13' 33.41" W

This permit is issued under the provisions of Chapter 403, Florida Statutes (F.S.), and applicable rules of the Florida Administrative Code (F.A.C.) and constitutes authorization to discharge to waters of the state under the National Pollutant Discharge Elimination System. This permit does not constitute authorization to discharge wastewater other than as expressly stated in this permit. The above named permittee is hereby authorized to operate the facilities in accordance with the documents attached hereto and specifically described as follows:

FACILITY DESCRIPTION:
This facility consists of seven coal-fired steam electric generating units (Units 1-7). Units 1-3 are currently retired and Units 4-7 are in use. The total nameplate capacity is 930 megawatts (MW) with a gross generation capacity of 994 MW. Units 4 and 5 use once-through cooling water (OTCW) for condenser cooling. A once-through helper cooling tower located at the discharge canal may be operated during the summer months (based on discharge temperature) to lower the temperature of the combined once-through cooling water discharge.

The closed-loop cooling tower systems for Units 6 and 7 use either reclaimed water from the Emerald Coast Utilities Authority (ECUA) Central Water Reclamation Facility (CWRF), FLA559351, or water from the Escambia River as makeup water. When river water is used as makeup for the Units 6 and 7 cooling towers, blowdown is discharged to the ash pond. When reclaimed water from ECUA is used as makeup for the Units 6 and 7 cooling towers, a portion of the blowdown (spent reclaimed water) from the cooling towers is used as process water for the flue gas desulfurization (FGD) system, and the remaining portion is returned to the headworks of the ECUA CWRF via the sanitary sewer collection system. During cooling tower outages, reclaimed water is used in the Units 4 and 5 OTCW systems.

WASTEWATER TREATMENT:
Non-process, once-through cooling water from Units 4 and 5 discharges to the Escambia River, a Class III fresh water. All treated and untreated industrial process wastewater is discharged to the ash pond or via underground injection (permit number IW0085658). Wastewater streams that discharge to the ash pond include: ash sluice water, overflow from the bottom ash dewatering bins, neutralized demineralizer regeneration wastewater, cooling tower blowdown, boiler blowdown, floor drainage, auxiliary equipment cooling water and seal water, coal pile runoff, yard sump discharge, and treated metal cleaning wastewater. The wastewater streams listed above that have the potential to contain oil are first routed through the oil skimmer pond prior to discharge to the ash pond. All domestic wastewater generated at the facility is collected and piped to Emerald Coast Utilities Authority (ECUA) sanitary sewer collection system.

Combustion By-Products management areas and their wastewater treatment.

Ash Landfill: on-site 78-acre solid waste management facility

Fly Ash Storage Area
Bottom Ash Storage Area.

Surface water runoff from the on-site solid waste management facility shall be collected into the stormwater pond which discharges through evaporation and percolation to groundwater or by a pipeline to the recycling cooling tower basin for Units 6 or 7.

Gypsum Storage Areas 1 and 2

The gypsum slurry is conveyed to either the new onsite lined gypsum storage area or the new gypsum dewatering system. Gypsum slurry that is transported to the storage area is stacked in piles. The gypsum solids will build up on the piles with the water separating from the solids by gravity. The produced water will be pumped into the return water pond.

Gypsum slurry that is routed to the gypsum dewatering system will be separated into two separate streams. One, referred to as filter cake, will contain mostly solids gypsum with little water while the other, referred to as filtrate, will be mostly water with little gypsum solids. The filter cake will be stored onsite until it is either loaded onto barges that are moored on Governor's Bayou or loaded to other types of transporters for delivery to wall board manufacturers. Gypsum determined not to meet the wall board manufacturing specifications may be marketed for agricultural use as authorized by the Florida Department of Agriculture and Consumer Services (FDACS) or other uses as authorized by the appropriate authorizing agency. The filtrate will be pumped to the return water pond.

Pumps will withdraw water from the return water pond to the return water tank for reuse back into the FGD system.

There are no surface water discharges associated with either the lined gypsum storage area or the gypsum dewatering system.

REUSE OR DISPOSAL:

Surface Water Discharge D-010: An existing 274 MGD maximum permitted discharge to Escambia River, Class III Fresh Waters, (WBID 10F). The point of discharge is located approximately at latitude 30° 33' 40" N, longitude 87° 13' 10" W.

Internal Outfall I-150: An existing permitted discharge to the on-site ash pond.

Internal Outfall I-170: An existing permitted discharge to the on-site ash pond.

Internal Outfall I-180: An existing permitted discharge to the intake tunnel for use as once-through cooling water.

Internal Outfall I-1C0: An existing permitted discharge to the main discharge canal prior to Outfall D-010.

IN ACCORDANCE WITH: The limitations, monitoring requirements and other conditions set forth in this Cover Sheet and Part I through Part IX on pages 1 through 35 of this permit.

PERMITTEE: Gulf Power Company
FACILITY: Crist Electric Generating Plant

PERMIT NUMBER: FL0002275 (Major)
EXPIRATION DATE: January 27, 2016

I. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

A. Surface Water Discharges

1. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **once-through non-contact cooling water, restricted supply of reclaimed water from ECUA, and ash pond overflow** from **Outfall D-010** to Escambia River. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.D.3.:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Daily Average Daily Maximum	Daily; 24 hours	Calculated	FLW-1	
Temperature (F), Water	Deg F	Min	94.0	Daily Average	Continuous	Calculated	EFF-1	See I.A.4
pH	s.u.	Min Max	6.0 8.5	Daily Minimum Daily Maximum	Weekly	Grab	EFF-1	
Oxidants, Total Residual	mg/L	Max Max	0.01 0.01	Monthly Average Daily Maximum	Weekly	Multiple Grab[1]	EFF-1	See I.A.5, I.A.6
Total Residual Oxidants (TRO) Discharge Time	min/ day/ unit	Max Max	120 120	Monthly Average Daily Maximum	Quarterly	Meter	EFF-1	See I.A.5, I.A.6
Oil and Grease	mg/L	Max Min	5.0 5.0	Monthly Average Daily Maximum	Quarterly	Grab	EFF-1	
Arsenic, Total Recoverable	ug/L	Max Max	50.0 50.0	Monthly Average Daily Maximum	Quarterly	24-hr TPC	EFF-1 INT-1	See I.A.8
Cadmium, Total Recoverable	ug/L	Max		Monthly Average Daily Maximum	Quarterly	24-hr TPC	EFF-1 INT-1	See I.A.7, I.A.8
Chromium, Hexavalent Total Recoverable	ug/L	Max Max	11 11	Monthly Average Daily Maximum	Quarterly	24-hr TPC	EFF-1 INT-1	See I.A.8, I.A.9
Copper, Total Recoverable	ug/L	Max		Monthly Average Daily Maximum	Quarterly	24-hr TPC	EFF-1 INT-1	See I.A.7, I.A.8
Iron, Total Recoverable	mg/L	Max Max	1.0 1.0	Monthly Average Daily Maximum	Quarterly	24-hr TPC	EFF-1 INT-1	See I.A.8
Lead, Total Recoverable	ug/L	Max		Monthly Average Daily Maximum	Quarterly	24-hr TPC	EFF-1 INT-1	See I.A.7, I.A.8
Mercury, Total Recoverable	ug/L	Max Max	0.012 0.012	Monthly Average Daily Maximum	Quarterly	Grab	EFF-1 INT-1	See I.A.8
Nickel, Total Recoverable	ug/L	Max		Monthly Average Daily Maximum	Annually	24-hr TPC	EFF-1 INT-1	See I.A.7, I.A.8
Selenium, Total Recoverable	ug/L	Max Max	5.0 5.0	Monthly Average Daily Maximum	Annually	24-hr TPC	EFF-1 INT-1	See I.A.8
Zinc, Total Recoverable	ug/L	Max		Monthly Average Daily Maximum	Quarterly	24-hr TPC	EFF-1 INT-1	See I.A.7, I.A.8
Hardness, Total (as CaCO3)	mg/L	Max	Report	Single Sample	Quarterly	24-hr TPC	EFF-1	
Alpha, Gross Particle Activity	pCi/L	Max Max	15.0 15.0	Monthly Average Daily Maximum	Quarterly	24-hr TPC	EFF-1 INT-1	See I.A.8
Radium 226 + Radium 228, Total	pCi/L	Max Max	5.0 5.0	Monthly Average Daily Maximum	Quarterly	24-hr TPC	EFF-1 INT-1	See I.A.8

[1] Multiple grabs for Total Residual Oxidants shall consist of grab samples collected at approximately the beginning of the period of expected oxidant discharge and once every 15 minutes thereafter until the end of the period of expected oxidant discharge.

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Chronic Whole Effluent Toxicity, 7-Day IC25 (Ceriodaphnia dubia/ Mysidopsis bahia)	percent	Min	100	Single Sample	Quarterly	24-hr TPC	EFF-1	See I.A.13
Chronic Whole Effluent Toxicity, 7-Day IC25 (Pimephales promelas/ Menidia beryllina)	percent	Min	100	Single Sample	Quarterly	24-hr TPC	EFF-1	See I.A.13

2. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.A.1. and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-1	Flow from condenser inlets.
EFF-1	Immediately upstream of the underflow at Thompson's Bayou.
INT-1	Intake to condensers.

3. The discharge shall not contain components that settle to form putrescent deposits or float as debris, scum, oil, or other matter. *[62-302.500(1)(a)]*

4. Pursuant to Condition I.A.1, the Maximum Daily Average temperature shall not exceed 94 °F over a 24 hour period as measured at EFF-1. However, the cooling towers for Units 1-5 shall be placed in full operation (defined as both booster pumps and all available fans, but not less than seven) as expeditiously as possible (but, in no case, no later than 45 minutes) after the discharge temperature exceeds 97.0°F as a 60 minute rolling average as measured at EFF-1(updated not less than every 15 minutes).

   The permittee shall maintain and operate the facilities so as to achieve compliance; however, failure to achieve compliance with this requirement does not constitute violation of this permit if due to mechanical malfunctions of pumps, fans, and/or other cooling tower components beyond the normal control of the permittee. Failure to have two booster pumps and all available fans (but not less than seven) when required shall be reported to the Department's Northwest District Office via telephone not later than the next business day and, in writing, within five business days of the occurrence. The reports shall provide all relevant information including, but not necessarily limited to, causes, temperatures, and period(s) of exceedance(s), plant loadings, unit(s) in operation, and remedial action taken.

5. Neither Free Available Oxidants nor Total Residual Oxidants shall be discharged for more than two hours per day from the main condensers serving Units 4-5.

6. Limitations and monitoring requirements for Total Residual Oxidants shall be applicable for any week in which either:

   a. The once-through cooling water intake is chlorinated; or

   b. An oxidant (e.g., chlorine or Nalco Actibrom 7342) is used in the cooling towers for Units 6 and 7 and the blowdown is discharged to surface waters of the state.

7. The limit for "Cadmium, Total Recoverable", "Copper, Total Recoverable", "Lead, Total Recoverable", "Nickel, Total Recoverable", and "Zinc, Total Recoverable" shall be calculated using the following equation(s):

   $Cd \leq e^{(0.7409[\ln H]-4.719)}$
   $Cu \leq e^{(0.8545[\ln H]-1.702)}$

$Pb \le e^{(1.273[\ln H]-4.705)}$
$Ni \le e^{(0.846[\ln H]+0.0584)}$
$Zn \le e^{(0.8473[\ln H]+0.884)}$

Total hardness shall be measured at the time of the effluent sample. The "ln H" means the natural logarithm of total hardness expressed as mg/L of $CaCO_3$. For metals criteria involving equations with hardness, the hardness shall be set at 25 mg/L if actual hardness is <25 mg/L and set at 400 mg/L if actual hardness is >400 mg/L.

The measured effluent value shall be recorded on the DMR in the parameter row for "Cadmium, Total Recoverable, Copper, Total Recoverable, Lead, Total Recoverable, Nickel, Total Recoverable, and Zinc, Total Recoverable (effluent)." The calculated effluent limit shall be recorded on the DMR in the parameter row for "Cadmium, Total Recoverable, Copper, Total Recoverable, Lead, Total Recoverable, Nickel, Total Recoverable, and Zinc, Total Recoverable (calculated limit)." Compliance with the effluent limitation is determined by calculating the difference between the measured effluent value and the calculated. The compliance value shall be recorded on the DMR in the parameter row for "Cadmium, Total Recoverable, Copper, Total Recoverable, Lead, Total Recoverable, Nickel, Total Recoverable, and Zinc, Total Recoverable (effluent minus calculated limit)." The compliance value shall not exceed 0.00. *[62-302.530(15), 62-302.530(23), 62-302.530(39), 62-302.530(44), and 62-302.530(70)]*

8. The actual limits for Arsenic, Cadmium, Chromium, Copper, Iron, Lead, Mercury, Nickel, Selenium, Zinc, Gross Alpha, and Combined Radium shall be the water quality standard set forth in 62-302.530, F.A.C. for Class III fresh waters (as provided in Conditions I.A.1 and I.A.7), or the concentration of the intake cooling water, whichever is greater. If the Outfall D-010 composite sample exceeds the intake concentration (and the intake concentration exceeds the water quality standard), a minimum of five (5) additional subsamples shall be measured from the original intake and outfall composites and a "student's t-test" shall be run on these additional subsamples comparing discharge concentrations with the intake concentrations; unless the discharge concentration exceeds the intake concentration at the 95% confidence level, the facility shall be in compliance with the limitation.

9. The permittee may sample and analyze for total recoverable Chromium in lieu of Chromium VI; however, if the total recoverable chromium result exceeds 11.0 µg/l then the permittee shall resample and Chromium VI analysis shall be performed and reported.

10. The permittee shall maintain the current intake through-screen velocity such that the existing maximum velocity is not exceeded. *[C.W.A. 316(b)]*

11. The permittee shall maintain current traveling screen practices at Units 1 and 2 so as to assure that the screens are cycled twice during each 24 hours of continuous operation unless precluded by repair/maintenance requirements. *[C.W.A. 316(b)]*

12. The permittee shall develop a plan in accordance with the schedule in Condition VI.3 to help return live fish, shellfish, and other aquatic organisms collected or trapped on the intake screens to their natural habitat. Other material shall be removed from the intake screens and disposed of in accordance with all existing Federal, State and/or Local laws and regulations that apply to waste disposal. Such material shall not be returned to the receiving waters. *[C.W.A. 316(b)]*

13. The permittee shall comply with the following requirements to evaluate chronic whole effluent toxicity of the discharge from outfall D-010.

    a. Effluent Limitation
        (1) In any routine or additional follow-up test for chronic whole effluent toxicity, the 25 percent inhibition concentration (IC25) shall not be less than 100% effluent. *[Rules 62-302.530(61) and 62-4.241(1)(b), F.A.C.]*
        (2) For acute whole effluent toxicity, the 96-hour LC50 shall not be less than 100% effluent in any test. *[Rule 62-302.500(1)(a)4. and 62-4.241(1)(a), F.A.C.]*

b. Monitoring Frequency
   (1) Routine toxicity tests shall be conducted once every three months, the first starting within 60 days of the issuance date of this permit and lasting for the duration of this permit.
   (2) Upon completion of four consecutive, valid routine tests that demonstrate compliance with the effluent limitation in 13.a.(1) above, the permittee may submit a written request to the Department for a reduction in monitoring frequency to once every six months. The request shall include a summary of the data and the complete bioassay laboratory reports for each test used to demonstrate compliance. The Department shall act on the request within 45 days of receipt. Reductions in monitoring shall only become effective upon the Department's written confirmation that the facility has completed four consecutive valid routine tests that demonstrate compliance with the effluent limitation in 13.a.(1) above.
   (3) If a test within the sequence of the four is deemed invalid based on the acceptance criteria in EPA-821-R-02-013, but is replaced by a repeat valid test initiated within 21 days after the last day of the invalid test, the invalid test will not be counted against the requirement for four consecutive valid tests for the purpose of evaluating the reduction of monitoring frequency.

c. Sampling Requirements
   (1) For each routine test or additional follow-up test conducted, a total of three 24-hour composite samples of final effluent shall be collected and used in accordance with the sampling protocol discussed in EPA-821-R-02-013, Section 8.
   (2) The first sample shall be used to initiate the test. The remaining two samples shall be collected according to the protocol and used as renewal solutions on Day 3 (48 hours) and Day 5 (96 hours) of the test.
   (3) Samples for routine and additional follow-up tests shall not be collected on the same day.

d. Test Requirements
   (1) Routine Tests: All routine tests shall be conducted using a control (0% effluent) and a minimum of five test dilutions: **100%, 50%, 25%, 12.5%**, and **6.25%** final effluent.
   (2) If the composite effluent salinity is less than 1.0 parts per thousand (ppt) measured as conductivity, the permittee shall conduct a daphnid, **Ceriodaphnia dubia**, Survival and Reproduction Test and a fathead minnow, **Pimephales promelas**, Larval Survival and Growth Test, concurrently. If the composite effluent sample salinity is greater than or equal to 1 ppm, measured as conductivity, the permittee may conduct 7-day survival and growth chronic toxicity tests with a mysid shrimp, **Americamysis (Mysidopsis) bahia**, Method 1007.0, and an inland silverside, **Menidia beryllina**, Method 1006.0, concurrently. When using freshwater species, the permittee should consider whether the salinity of the composite effluent in the second and third sample will continue to be less than 1 ppt.
   (3) All test species, procedures and quality assurance criteria used shall be in accordance with **Short-term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Freshwater Organisms**, 4th Edition, EPA-821-R-02-013 if using freshwater species; and **Short-term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Marine and Estuarine Organisms**, 3rd Edition, EPA-821-R-02-014, if using saltwater species. Any deviation of the bioassay procedures outlined herein shall be submitted in writing to the Department for review and approval prior to use. In the event the above method is revised, the permittee shall conduct chronic toxicity testing in accordance with the revised method.
   (4) (a) If freshwater species are used, the control water and dilution water shall be moderately hard water as described in EPA-821-R-02-013, Section 7.2.3.
   (b) If saltwater species are used, the control water and dilution water used shall be artificial sea salts as described in EPA-821-R-02-014, Section 7.2. The test salinity shall be determined as follows:
      i. For the **Americamysis bahia** bioassays, the effluent shall be adjusted to a salinity of 20 parts per thousand (ppt) with artificial sea salts. The salinity of the control/dilution water (0% effluent) shall be 20 ppt. If the salinity of the effluent is greater than 20 ppt, no salinity adjustment shall be made to the effluent and the test shall be run at the effluent salinity. The salinity of the control/dilution water shall match the salinity of the effluent.
      ii. For the **Menidia beryllina** bioassays, if the effluent salinity is less than 5ppt, the salinity shall be adjusted to 5 ppt with artificial sea salts. The salinity of the control/dilution water (0% effluent) shall be 5 ppt. If the salinity of the effluent is greater than 5 ppt, no salinity adjustment shall be made to the effluent and the test shall be run at the effluent salinity. The salinity of the control/dilution water shall match the salinity of the effluent.

iii. If the salinity of the effluent requires adjustment, a salinity adjustment control should be prepared and included with each bioassay. The salinity adjustment control is intended to identify toxicity resulting from adjusting the effluent salinity with artificial sea salts. To prepare the salinity adjustment control, dilute the control/dilution water to the salinity of the effluent and adjust the salinity of the salinity adjustment control at the same time and to the same salinity that the salinity of the effluent is adjusted using the same artificial sea salts.

e. Quality Assurance Requirements

(1) A standard reference toxicant (SRT) quality assurance (QA) chronic toxicity test shall be conducted with each species used in the required toxicity tests either concurrently or initiated no more than 30 days before the date of each routine or additional follow-up test conducted. Additionally, the SRT test must be conducted concurrently if the test organisms are obtained from outside the test laboratory unless the test organism supplier provides control chart data from at least the last five monthly chronic toxicity tests using the same reference toxicant and test conditions. If the organism supplier provides the required SRT data, the organism supplier's SRT data and the test laboratory's monthly SRT-QA data shall be included in the reports for each companion routine or additional follow-up test required.

(2) If the mortality in the control (0% effluent) exceeds 20% for either species in any test or any test does not meet "test acceptability criteria", the test for that species (including the control) shall be invalidated and the test repeated. Test acceptability criteria for each species are defined in EPA-821-R-02-013, Section 13.12 (**Ceriodaphnia dubia**) and Section 11.11 (**Pimephales promelas**); and EPA-821-R-02-014, Section 14.12 (**Americamysis bahia**) and Section 13.12 (**Menidia beryllina**). The repeat test shall begin within 21 days after the last day of the invalid test.

(3) If 100% mortality occurs in all effluent concentrations for either test species prior to the end of any test and the control mortality is less than 20% at that time, the test (including the control) for that species shall be terminated with the conclusion that the test fails and constitutes non-compliance.

(4) Routine and additional follow-up tests shall be evaluated for acceptability based on the observed dose-response relationship as required by EPA-821-R-02-013, or EPA-821-R-02-014 Section 10.2.6., and the evaluation shall be included with the bioassay laboratory reports.

f. Reporting Requirements

(1) Results from all required tests shall be reported on the Discharge Monitoring Report (DMR) as follows:

i. Routine and Additional Follow-up Test Results: The calculated IC25 for each test species shall be entered on the DMR.

(2) A bioassay laboratory report for each routine test shall be prepared according to EPA-821-R-02-013, EPA-821-R-02-014, Section 10, Report Preparation and Test Review, and mailed to the Department at the address below within 30 days after the last day of the test.

(3) For additional follow-up tests, a single bioassay laboratory report shall be prepared according to EPA-821-R-02-013 or EPA-821-R-02-014, Section 10, and mailed within 30 days after the last day of the second valid additional follow-up test.

(4) Data for invalid tests shall be included in the bioassay laboratory report for the repeat test.

(5) The same bioassay data shall not be reported as the results of more than one test.

(6) All bioassay laboratory reports shall be sent to:
Florida Department of Environmental Protection
Northwest District Office
160 Governmental Center
Pensacola, Florida 32502-5794

g. Test Failures

(1) A test fails when the test results do not meet the limits in 13.a.(1).

(2) Additional Follow-up Tests:

(a) If a routine test does not meet the chronic toxicity limitation in 13.a.(1) above, the permittee shall notify the Department at the address above within 21 days after the last day of the failed routine test and conduct two additional follow-up tests on each species that failed the test in accordance with 13.d.

(b) The first test shall be initiated within 28 days after the last day of the failed routine test. The remaining additional follow-up tests shall be conducted weekly thereafter until a total of two valid additional follow-up tests are completed.

(c) The first additional follow-up test shall be conducted using a control (0% effluent) and a minimum of five dilutions: 100%, 50%, 25%, 12.5%, and 6.25% effluent. The permittee may modify the dilution series in the second additional follow-up test to more accurately bracket the toxicity such that at least two dilutions above and two dilutions below the target concentration and a control (0% effluent) are run. All test results shall be analyzed according to the procedures in EPA-821-R-02-013 or EPA-821-R-02-014, as appropriate.

(3) In the event of three valid test failures (whether routine or additional follow-up tests) within a 12-month period, the permittee shall notify the Department within 21 days after the last day of the third test failure.
- (a) The permittee shall submit a plan for correction of the effluent toxicity within 60 days after the last day of the third test failure.
- (b) The Department shall review and approve the plan before initiation.
- (c) The plan shall be initiated within 30 days following the Department's written approval of the plan.
- (d) Progress reports shall be submitted quarterly to the Department at the address above.
- (e) During the implementation of the plan, the permittee shall conduct quarterly routine whole effluent toxicity tests in accordance with 13.d. Additional follow-up tests are not required while the plan is in progress. Following completion or termination of the plan, the frequency of monitoring for routine and additional follow-up tests shall return to the schedule established in 13.b.(1). If a routine test is invalid according to the acceptance criteria in EPA-821-R-02-013, or EPA-821-R-02-014, as appropriate, a repeat test shall be initiated within 21 days after the last day of the invalid routine test.
- (f) Upon completion of four consecutive quarterly valid routine tests that demonstrate compliance with the effluent limitation in 13.a.(1) above, the permittee may submit a written request to the Department to terminate the plan. The plan shall be terminated upon written verification by the Department that the facility has passed at least four consecutive quarterly valid routine whole effluent toxicity tests. If a test within the sequence of the four is deemed invalid, but is replaced by a repeat valid test initiated within 21 days after the last day of the invalid test, the invalid test will not be counted against the requirement for four consecutive quarterly valid routine tests for the purpose of terminating the plan.

(4) If chronic toxicity test results indicate greater than 50% mortality within 96 hours in an effluent concentration equal to or less than the effluent concentration specified as the acute toxicity limit in 13.(a)(2), the Department may revise this permit to require acute definitive whole effluent toxicity testing.

(5) The additional follow-up testing and the plan do not preclude the Department taking enforcement action for acute or chronic whole effluent toxicity failures.

[62-4.241, 62-620.620(3)]

B. Internal Outfalls

1. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **ash pond overflow from Internal Outfall I-1C0** to the main discharge canal prior to D-010. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.D.3.:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Daily Maximum Monthly Average	Daily, when discharging	Totalizer[2]	FLW-3	
Oil and Grease	mg/L	Max	7.0	Monthly Average	Bi-weekly;	Grab	EFF-2	

[2] Recording flow meters and totalizers shall be calibrated at least annually.

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
		Max	10.0	Daily Average	every 2 weeks			
Solids, Total Suspended	mg/L	Max Max	30.0 65.0	Monthly Average Daily Average	Weekly, when discharging	24-hr TPC	EFF-2	
Hydrazine	mg/L	Max	300	Instantaneous Maximum	See I.B.3	Multiple Grab	EFF-2	See I.B.3
pH	s.u.	Min Max	6.0 9.0	Daily Minimum Daily Maximum	Weekly, when discharging	Grab	EFF-2	

2. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.1**Error! Reference source not found.**. and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-3	Flow from ash pond discharge weir.
EFF-2	Ash pond discharge weir.

3. The monitoring frequency for hydrazine shall be three times per cold dump discharge event when the amount of residual hydrazine in the boiler water discharged into the ash pond during a two day period exceeds the threshold level of 43.2 kg. Grab samples shall be taken at 6, 12, and 24 hours from the time approximately 50 percent of the discharge is complete. The total amount of hydrazine going to the ash pond will be calculated by multiplying the capacity of each boiler being dumped within a two day period by the measured hydrazine residual concentration in that boiler.

   For the purposes of this condition, a two day period begins at the start of a boiler discharge to the pond and includes the subsequent 48 hours. Monitoring for hydrazine is not required during a cold dump discharge event provided the total boiler water residual hydrazine amount being discharged is below 43.2 kg. The facility will establish and maintain a log to verify the total residual level being discharged to the ash pond.

   A discharge event is defined as a cold dump of a single boiler following cold stand-by status which required hydrazine to be added to the boiler water to achieve concentrations higher than normal for protection of metal surfaces. Boiler blowdown, under normal operating conditions with hydrazine concentrations of 10 to 50 μg/l, may be discharged without limitations or monitoring requirements for hydrazine.

4. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **metal cleaning wastewater** from **Internal Outfall I-150** to the ash pond. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.D.3.:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Monthly Average Daily Maximum	Per discharge	Calculated	FLW-4	
Copper, Total Recoverable	mg/L	Max Max	1.0 1.0	Monthly Average Daily Maximum	Per discharge	Time Proportional Composite[3]	EFF-3	
Iron, Total Recoverable	mg/L	Max Max	1.0 1.0	Daily Maximum Monthly Average	Per discharge	Time Proportional Composite[3]	EFF-3	
Solids, Total Suspended	mg/L	Max Max	30.0 100.0	Monthly Average Daily Maximum	Per discharge	Time Proportional Composite[3]	EFF-3	
Oil and Grease	mg/L	Max Max	15.0 20.0	Monthly Average Daily Maximum	Per discharge	Grab	EFF-3	

5. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.4. and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-4	Flow from metal cleaning treatment pond.
EFF-3	Metal cleaning treatment pond pump discharge.

6. Metal cleaning wastes shall mean any chemical cleaning compounds, initial rinse waters following each chemical cleaning, or any other waterborne residues derived from chemical cleaning any metal process equipment including, but not limited to, boiler tube cleaning, boiler fireside cleaning, and air preheater cleaning.

7. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **cooling tower blowdown from Internal Outfall I-170** to the ash pond **only when river water is used as makeup water for the Units 6 and 7 cooling towers.** Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.D.3.:

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
Flow	MGD	Max Max	Report Report	Monthly Average Daily Maximum	Weekly, when discharging	Calculated	FLW-5	
Total Residual Oxidants Discharge Time	min/day	Max Max	120 120	Monthly Average Daily Maximum	Daily, when discharging	Meter	EFF-1	See I.B.9
Oxidants, Free Available	mg/L	Max Max	0.2 0.5	Monthly Average Daily Maximum	Per occurrence	Grab	OUI-6	See I.B.10
Chromium, Total Recoverable	mg/L	Max Max	0.2 0.2	Monthly Average Daily Maximum	Quarterly, when discharging	Grab	OUI-6	
Zinc, Total Recoverable	mg/L	Max Max	1.0 1.0	Monthly Average Daily Maximum	Quarterly, when discharging	Grab	OUI-6	

[3] One aliquot collected immediately after the start of discharge to the ash pond, one aliquot immediately prior to termination of the discharge, and six aliquots collected at approximately equal times in between.

			Effluent Limitations		Monitoring Requirements			
Parameter	Units	Max/ Min	Limit	Statistical Basis	Frequency of Analysis	Sample Type	Monitoring Site Number	Notes
126 priority pollutants	mg/L	Max Max	<MDL <MDL	Monthly Average Daily Maximum	Annually	Grab or Calculation	OUI-6	See I.B.11

8. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.7. and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-5	Flow of reclaimed water pipeline for makeup of Units 6 and 7 cooling towers.
OUI-6	Cooling tower conveyance line, prior to valve that directs blowdown to either the intake structure or the ash pond.

9. Total Residual Oxidants (TRO) shall not be discharged from Unit 6 and 7 cooling towers for more than two hours per day when river water is used as make-up water.

10. Limitations and monitoring requirements for Free Available Oxidants shall be applicable when an oxidant (e.g., chlorine or Nalco Actibrom 7342) is used in the cooling towers for Units 6 and 7 and the blowdown is discharged to the ash pond.

11. The permittee shall, within 30 days of permit issuance and yearly thereafter, provide certification that the 126 priority pollutants (as listed in 40 CFR Part 423, Appendix A) are below the method detection limits (MDL) for the applicable analytical methods required under permit Condition I.B.7 in the cooling tower blowdown as a result of the addition of any maintenance chemicals. Compliance shall be demonstrated by one of the three methods:

    Method 1: Sampling at a frequency of not less than once per year for all priority pollutants referenced above with submission of analysis results with each certification.

    Method 2: Submission of certification(s) from the manufacturer that each product used contains no priority pollutants. Such submission is required only once for each product used, unless subsequent changes in the product formulation occur or the product is obtained from a different source. Certifications for all products in use shall be maintained on site.

    Method 3: Calculations to assure that if priority pollutants are contained in any product(s), no discharge of any individual priority pollutant can occur at concentrations greater than detectable levels using analytical methods in 40 CFR Part 136 due to dilution within the cooling water system.

    The certification shall be in the following form: "I certify that no priority pollutants at concentrations greater than detectable levels using analytical methods in 40 CFR Part 136 are being discharged from any maintenance chemicals added to the cooling towers. Compliance is demonstrated by Method____."

12. During the period beginning on the issuance date and lasting through the expiration date of this permit, the permittee is authorized to discharge **ECUA reclaimed water and spent reclaimed water** through **Internal Outfall I-180** to the intake tunnel for use in the OTCW for Units 4 and 5 **during scheduled and unscheduled outages of Unit 6 or Unit 7 cooling towers**. Such discharge shall be limited and monitored by the permittee as specified below and reported in accordance with Permit Condition I.D.3.:

			Effluent Limitations		Monitoring Requirements			
Parameter	**Units**	**Max/ Min**	**Limit**	**Statistical Basis**	**Frequency of Analysis**	**Sample Type**	**Monitoring Site Number**	**Notes**
Flow	MGD	Max	20 Report	Daily Annual Average Monthly Average	Continuous	Totalizer[4]	FLW-5	
		Max Max Max	855 Report Report	Annual Maximum Monthly Average Daily Maximum	Continuous	Totalizer[4]	FLW-6 FLW-7	See I.B.15, I.B.16
Duration of Discharge	hr	Max Max	Report Report	Annual Total Monthly Total	Weekly, when discharging	Calculated	FLW-6 FLW-7	
Total Residual Oxidants Discharge Time	min/ day	Max Max	120 120	Monthly Average Daily Maximum	Weekly; when discharging	Calculated	OUI-6 OUI-7	See I.B.21
Oxidants, Total Residual	mg/L	Max Max	0.2 0.5	Monthly Average Daily Maximum	Weekly, when discharging	Grab	OUI-6 OUI-7	
Chromium, Total Recoverable	mg/L	Max Max	0.2 0.2	Monthly Average Daily Maximum	Quarterly, when discharging	Grab	OUI-6 OUI-7	See I.B.23
Zinc, Total Recoverable	mg/L	Max Max	1.0 1.0	Monthly Average Daily Maximum	Quarterly, when discharging	Grab	OUI-6 OUI-7	See I.B.23
Nitrogen, Ammonia, Total (as N)	mg/L	Max Max Max	Report Report Report	Monthly Average Weekly Average Daily Maximum	Weekly, when discharging	Grab	OUI-5 OUI-6 OUI-7	
Nitrogen, Kjeldahl, Total (as N)	mg/L	Max Max Max	Report Report Report	Monthly Average Weekly Average Daily Maximum	Weekly, when discharging	Grab	OUI-5 OUI-6 OUI-7	
Nitrite plus Nitrate, Total (as N)	mg/L	Max Max Max	Report Report Report	Monthly Average Weekly Average Daily Maximum	Weekly, when discharging	Grab	OUI-5 OUI-6 OUI-7	
Nitrogen, Total	mg/L	Max Max Max	3.75 4.5 6.0	Monthly Average Weekly Average Daily Maximum	Weekly, when discharging	Calculated	OUI-5	See I.B.17
		Max Max	Report Report	Monthly Average Weekly Average	Weekly, when discharging	Grab	OUI-6 OUI-7	See I.B.17
Nitrogen, Total (Monthly Net Loading)	lb/mth	Max	Report	Monthly Total	Weekly, when discharging	Grab	OUI-5 OUI-6 OUI-7	See I.B.17
Nitrogen, Total (Annual Net Loading)	lb/yr	Max	Report	Annual Total	Weekly, when discharging	Calculated	OUI-5 OUI-6 OUI-7	See I.B.17
Phosphorus, Total (as P)	mg/L	Max Max Max	0.4 0.6 0.8	Monthly Average Weekly Average Daily Maximum	Weekly, when discharging	Grab	OUI-5	See I.B.18, I.B.19
		Max	Report	Weekly Average	Weekly, when discharging	Grab	OUI-6 OUI-7	See I.B.19
Phosphorus, Total (as P) (Monthly Net Loading)	lb/mth	Max	Report	Monthly Total	Weekly, when discharging	Grab	OUI-5 OUI-6 OUI-7	See I.B.17
Phosphorus, Total (as P) (Annual Net Loading)	lb/yr	Max	Report	Annual Total	Weekly, when discharging	Calculated	OUI-5 OUI-6 OUI-7	See I.B.17

[4] Recording flow meters and totalizers shall be calibrated at least annually

13. Effluent samples shall be taken at the monitoring site locations listed in Permit Condition I.B.12. and as described below:

Monitoring Site Number	Description of Monitoring Site
FLW-5	Flow of reclaimed water pipeline for makeup of Units 6 and 7 cooling towers.
FLW-6	Flow of reclaimed and spent reclaimed water directed for reuse into the intake tunnel.
FLW-7	Flow of reclaimed and spent reclaimed water directed for reuse into the discharge tunnel.
OUI-5	Reclaimed water pipeline for makeup of Units 6 and 7 cooling towers.
OUI-6	Cooling tower conveyance line, prior to valve that directs blowdown to either the intake structure or the ash pond.
OUI-7	Reclaimed water pipeline prior to discharge into the discharge tunnel.

14. Planned (anticipated) outages shall be scheduled for the months of October through April unless the Department approves otherwise. The permittee shall seek approval from the Department at least 30 days prior to each outage not planned for the months of October through April. The permittee shall submit a request to the Department at the address specified below:

Florida Department of Environmental Protection
Industrial Wastewater Section, Mail Station 3545
Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

15. During outages when both Unit 6 and 7 cooling towers are offline, the permittee shall reuse up to11.5 MGD, with a total maximum of 207 million gallons per year, of reclaimed water from ECUA and spent reclaimed water through Internal Outfall I-180. The term outage includes Unit 6 and 7 cooling towers transitioning from reclaimed water to river water and vice-versa as makeup water.

16. During outages when either Unit 6 or 7 cooling tower is off-line, the permittee shall reuse up to 7.4 MGD, with a total maximum of 648 million gallons per year, of reclaimed water from ECUA and spent reclaimed water through Internal Outfall I-180. The term outage includes Unit 6 or 7 cooling tower transitioning from reclaimed water to river water and vice-versa as makeup water.

17. The net Total Nitrogen (TN) loading is defined as the pounds of TN discharged at OUI-6 minus the pounds of TN in the makeup water for Units 6 and 7 cooling towers at OUI-5, over a corresponding time period. The permittee shall report the monthly net TN loading, which equals the pounds of TN discharged during a month minus the pounds of TN entering Units 6 and 7 cooling towers during the same month. The annual net TN loading (in pounds per year) on any given month is equal to the monthly TN net loading for that month plus the previous eleven monthly TN loadings and is considered a rolling annual maximum value.

18. The permittee shall not add nitrogen or phosphorous containing products to the Unit 6 and 7 cooling towers without Department approval.

19. During the first 24 hours of reuse through Internal Outfall I-180 for unscheduled outages, the single sample maximum for Total Phosphorus shall be 2.0 mg/L.

20. Unscheduled discharges shall be subject to General Conditions VIII.22 and VIII.23 for bypass and upset.

21. Neither Free Available Oxidants nor Total Residual Oxidants shall be discharged for more than two hours per day from the cooling towers for Units 6 and 7 when discharging the blowdown to surface waters of the State.

22. Limitations and monitoring requirements for Total Residual Oxidants and Free Available Oxidants shall be applicable when an oxidant (e.g., chlorine or Nalco Actibrom 7342) is used in the cooling towers for Units 6 and 7 and discharging the blowdown to surface waters of the state.

23. Limitations and monitoring requirements for Total Recoverable Chromium and Total Recoverable Zinc shall be applicable when discharging the cooling tower blowdown to surface waters of the state.

24. The permittee shall meet the Department-approved ECUA pretreatment program requirements when discharging to ECUA sanitary sewer system.

C. Underground Injection Control Systems

1. Requirements for the discharge from the FGD scrubber to two Class I injection wells (IW-1 and IW-2) are established under Department UIC Permit Number IW17-0085658-001-UC.

D. Other Limitations and Monitoring and Reporting Requirements

1. The sample collection, analytical test methods, and method detection limits (MDLs) applicable to this permit shall be conducted using a sufficiently sensitive method to ensure compliance with applicable water quality standards and effluent limitations and shall be in accordance with Rule 62-4.246, Chapters 62-160 and 62-601, F.A.C., and 40 CFR 136, as appropriate. The list of Department established analytical methods, and corresponding MDLs (method detection limits) and PQLs (practical quantitation limits), which is titled "FAC 62-4 MDL/PQL Table (April 26, 2006)" is available at http://www.dep.state.fl.us/labs/library/index.htm. The MDLs and PQLs as described in this list shall constitute the minimum acceptable MDL/PQL values and the Department shall not accept results for which the laboratory's MDLs or PQLs are greater than those described above unless alternate MDLs and/or PQLs have been specifically approved by the Department for this permit. Any method included in the list may be used for reporting as long as it meets the following requirements:

   a. The laboratory's reported MDL and PQL values for the particular method must be equal or less than the corresponding method values specified in the Department's approved MDL and PQL list;

   b. The laboratory reported MDL for the specific parameter is less than or equal to the permit limit or the applicable water quality criteria, if any, stated in Chapter 62-302, F.A.C. Parameters that are listed as "report only" in the permit shall use methods that provide an MDL, which is equal to or less than the applicable water quality criteria stated in 62-302, F.A.C.; and

   c. If the MDLs for all methods available in the approved list are above the stated permit limit or applicable water quality criteria for that parameter, then the method with the lowest stated MDL shall be used.

   When the analytical results are below method detection or practical quantitation limits, the permittee shall report the actual laboratory MDL and/or PQL values for the analyses that were performed following the instructions on the applicable discharge monitoring report.

   Where necessary, the permittee may request approval of alternate methods or for alternative MDLs or PQLs for any approved analytical method. Approval of alternate laboratory MDLs or PQLs are not necessary if the laboratory reported MDLs and PQLs are less than or equal to the permit limit or the applicable water quality criteria, if any, stated in Chapter 62-302, F.A.C. Approval of an analytical method not included in the above-referenced list is not necessary if the analytical method is approved in accordance with 40 CFR 136 or deemed acceptable by the Department. *[62-4.246, 62-160]*

2. The permittee shall provide safe access points for obtaining representative influent and effluent samples which are required by this permit. *[62-620.320(6)]*

3. Monitoring requirements under this permit are effective on the first day of the second month following permit issuance. Until such time, the permittee shall continue to monitor and report in accordance with previously effective permit requirements, if any. During the period of operation authorized by this permit, the permittee shall complete and submit to the Department Discharge Monitoring Reports (DMRs) in accordance with the frequencies specified by the REPORT type (i.e. monthly, toxicity, quarterly, semiannual, annual, etc.) indicated on the DMR forms attached to this permit. Monitoring results for each monitoring period shall be submitted in accordance with the associated DMR due dates below.

REPORT Type on DMR	Monitoring Period	Due Date
Monthly or Toxicity	first day of month - last day of month	28th day of following month
Quarterly	January 1 - March 31 April 1 - June 30 July 1 - September 30 October 1 - December 31	April 28 July 28 October 28 January 28

REPORT Type on DMR	Monitoring Period	Due Date
Semiannual	January 1 - June 30 July 1 - December 30	July 28 January 28
Annual	January 1 - December 31	January 28

DMRs shall be submitted for each required monitoring period including months of no discharge. The permittee may submit either paper or electronic DMR form(s). If submitting paper DMR form(s), the permittee shall make copies of the attached DMR form(s). If submitting electronic DMR form(s), the permittee shall use a Department-approved electronic DMR system.

The electronic submission of DMR forms shall accepted only if approved in writing by the Department. For purposes of determining compliance with this permit, data submitted in electronic format is legally equivalent to data submitted on signed and certified DMR forms.

The permittee shall submit the completed DMR form(s) to the Department by the twenty-eighth (28th) of the month following the month of operation at the addresses specified below:

Florida Department of Environmental Protection
Wastewater Compliance Evaluation Section, Mail Station 3551
Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

[62-620.610(18)]

4. Unless specified otherwise in this permit, all reports and other information required by this permit, including 24-hour notifications, shall be submitted to or reported to, as appropriate, the Department's Northwest Office at the address specified below:

   Florida Department of Environmental Protection
   Northwest District Office
   160 Government Center
   Pensacola, Florida 32501-5794

   Phone Number - (850) 595-8300
   FAX Number - (850) 595-8417 (All FAX copies and e-mails shall be followed by original copies.)

   [62-620.305]

5. All reports and other information shall be signed in accordance with the requirements of Rule 62-620.305, F.A.C. *[62-620.305]*

6. If there is no discharge from the facility on a day when the facility would normally sample, the sample shall be collected on the day of the next discharge. *[62-620.320(6)]*

7. There shall be no discharge of polychlorinated biphenyl compounds such as those commonly used for transformer fluid. *[40 CFR Part 423.12(b)(2)]*

8. Discharge of any product registered under the Federal Insecticide, Fungicide, and Rodenticide Act to any waste stream which ultimately may be released to waters of the State is prohibited unless specifically authorized elsewhere in this permit. This requirement is not applicable to products used for lawn and agricultural purposes or to the use of herbicides if used in accordance with labeled instructions and any applicable State permit. A permit revision from the Department shall be required prior to the use of any biocide or chemical additive used in the cooling system (except chlorine as authorized elsewhere in this permit) or any other portion of the treatment system which may be toxic to aquatic life. The permit revision request shall include:
   a. Name and general composition of biocide or chemical

b. Frequencies of use

c. Quantities to be used

d. Proposed effluent concentrations

e. Acute and/or chronic toxicity data (laboratory reports shall be prepared according to Section 12 of EPA document no. EPA-821-R-02-012 EP entitled, Methods for Measuring the Acute Toxicity of Effluents and Receiving Waters for Freshwater and Marine Organisms, or most current addition.)

f. Product data sheet

g. Product label

The Department shall review the above information to determine if a major or minor permit revision is necessary. Discharge associated with the use of such biocide or chemical is not authorized without a permit revision by the Department. Permit revisions shall be processed in accordance with the requirements of Chapter 62-620, F.A.C.

The permittee shall submit the aforementioned information to and obtain written permission from Escambia County Utility Authority (ECUA) to use any biocide or chemical additive in Unit 6 or 7 cooling tower prior to requesting a permit revision from the Department. The permittee shall provide proof of permission from ECUA as part of the permit revision application.

9. Discharge of uncontaminated storm water, intake screen backwash water, turbine oil cooler water, and hydrogen generator cooler water is permitted without limitations or monitoring requirements, except that there shall be no discharge of floating oil.

10. Discharge of any waste resulting from the combustion of toxic, hazardous, or metal cleaning wastes to any waste stream which ultimately discharges to waters of the State is prohibited, unless specifically authorized elsewhere in this permit. The discharge of plant ash transport water, resulting from the combustion of on-specification used oil as authorized under the Resource Conservation and Recovery Act and 40 CFR Part 266, via the ash pond shall be an authorized discharge of this permit.

11. The permittee shall not store coal, soil, or other similar erodable materials in a manner in which runoff is uncontrolled, or conduct construction activities in a manner which produces uncontrolled runoff.

12. The permittee shall notify the Department and ECUA when directing ECUA reclaimed water or spent reclaimed water for reuse as OTCW during outages, as follows:

    a. Notify the Department's Northwest District and the Superintendent of ECUA in writing at least seven days before the start date of scheduled outages at the Units 6 or 7 cooling towers.

    b. Notify the Department's Northwest District and the Superintendent of ECUA of an unscheduled outage as required by Condition X.22.

13. The permittee is authorized to utilize the following water treatment chemicals and biocides in the recirculating cooling tower systems for generating Units 6 and 7 and other wastewater streams:

Chemical Name	System Used
Sodium Hypochlorite	Units 6 and 7 Cooling Tower System
Betz Depositrol PY5200	Units 6 and 7 Cooling Tower System
Betz Dearborn AF1440	Units 6 and 7 Cooling Tower System
Ondeo Nalco 9353	Units 6 and 7 Cooling Tower System
Ondeo Nalco 7468	Units 6 and 7 Cooling Tower System
Nalco 73200	Units 6 and 7 Cooling Tower System
Nalco Actibrom 7342	Units 6 and 7 Cooling Tower System
Sulfuric Acid (93% by weight)	Units 6 and 7 Cooling Tower System
Nalsperse 7308	Units 4 & 5, 6 & 7 Service Water Systems

Chemical Name	System Used
Ferric Chloride	Ash Pond
Nalco Optimer® 7128 @ 0.5 mg/L	Ash Pond
Nalco Cat-Floc 8103 Plus @ 5.0 mg/L	Ash Pond

14. The permittee is authorized to use the treatment additive Nalsperse 7308 in the facility's service water systems for Units 4 and 5, and Units 6 and 7. Discharges from the service water systems shall not be concurrent, and not within 48 hours of one another.

15. The permittee is authorized to use the treatment additives Nalco Optimer® 7128 and Nalco Cat-Floc 8103 Plus in the facility's ash pond on an intermittent basis for turbidity control. During the first period of usage of each of the two chemicals, the permittee shall:

    a. Record the amount used and the duration of the chemical application in the ash pond;

    b. Calculate and record the maximum expected final effluent concentration;

    c. Perform a chronic toxicity test in accordance with the procedures listed in Condition I.A.13, with the inclusion of the following:

        (1) The toxicity test shall be performed using effluent from the ash pond containing either chemical, with the appropriate dilution with once-through non-contact cooling water from Units 4 and 5. 24-hour composite sampling of the effluent from the ash pond shall begin when the chemical is expected to be discharged out of the ash pond. The once-through non-contact cooling water used to prepare the dilution may be a grab sample. The dilution shall represent the typical ratio of ash pond water to cooling water contained in the final effluent at Outfall D-001 and shall constitute the 100% effluent sample in the procedures of Condition I.A.13.

        (2) Results of the toxicity test shall be sent to:

        Florida Department of Environmental Protection
        Industrial Wastewater Section, Mail Station 3545
        Bob Martinez Center
        2600 Blair Stone Road
        Tallahassee, Florida 32399-2400

II. COMBUSTION BY-PRODUCTS MANAGEMENT REQUIREMENTS

1. Combustion by-products produced by the operation of Plant Crist: ash, non-hazardous metal cleaning wastewater sludge, and other solid waste approved by the Department shall be disposed of in the on-site 78-acre solid waste management facility permitted through this permit or to another appropriate solid waste management facility permitted by the Department.

2. The disposal of combustion by-products in the on-site solid waste management facility permitted by the this permit shall be in accordance with the construction permit, IC17-031700, issued October 13, 1980, and the requirements of Chapter 62-701, F.A.C., except as modified by Evaluation of Solid Waste Management Practices and Requirements for the Florida Electric Utility Industry.

3. A copy of the engineering drawings, plans, reports, construction permit, and supporting information shall be kept at this landfill at all times for reference and inspections.

4. In no event shall any solid waste other than combustion by-products or other materials approved by the Department be disposed of on the plant site other than in areas specifically designated in the application. Small amounts of accumulated debris that has been removed from the plant's cooling water intake screens, consisting mainly of vegetation, may be placed in a central location near the ash landfill.

5. The solid waste management facility has been and will be constructed in phases.

6. The final cover system, including the drainage soil, top soil and seeding, shall be completed within 180 days after the final waste deposit date.

7. Final closure of the facility shall comply with the provisions of Rules 62-701.600 through 62-701.620, FAC, except as modified by Evaluation of Solid Waste Management Practices and Requirements for the Florida Electric Utility Industry and any additional requirements in effect at the time wastes cease to be accepted by the facility.

8. Surface water runoff shall be controlled during operation under this permit and shall comply with Chapter 62-302, F.A.C., at the site boundary. Specifically, surface water runoff from the on-site solid waste management facility shall be collected into the stormwater pond which discharges through evaporation or percolation to groundwater and by a pipeline to the recycling cooling tower basin for Units 6 or 7.

III. GROUND WATER REQUIREMENTS

1. The allowable zone of discharge (ZOD) for this permit shall be as follows:

   a. The horizontal ZOD shall consist of the north, south, and west property lines and the un-submerged land limits to the east as shown on Drawing Number ES1607.dwg, October 23, 2007, as shown in Attachment 2.

   b. The vertical ZOD shall extend from the land surface down to the top of the low permeability zone at the base of Unit 2 at approximately -10 to -40 feet National Geodetic Vertical Datum (ft. NGVD).

   c. Compliance with water quality standards of Rule 62-520.420, F.A.C., and as contained in Rule 62-550.310, F.A.C. and Rule 62-550.320, F.A.C. shall be met at and beyond the edges of the ZOD. Compliance with minimum groundwater criteria of Rule 62-520.400, F.A.C. shall be met within and beyond the edge of the ZOD. Surface water criteria in accordance with Rule 62-302.500, F.A.C. and Rule 62-302.530, F.A.C. shall be met beyond the ZOD. *[Permit application received Date and subsequent incompleteness information]*

2. Any new or replacement wells shall be of an appropriate diameter so as to provide reliable and representative water quality results. They shall have appropriate screen length and shall be constructed in accordance with the guidelines provided on Attachment 3. Sieve analyses shall be submitted and shall be used for proper well design. Monitoring wells should be locked to minimize the potential for unauthorized access in accordance with Rule 62-701.510(3)(d).5, F.A.C. Required well construction permits shall be obtained from the Northwest Florida Water Management District. Upon installation and after settling, new wells shall be properly developed. Upon completion of construction of new wells, the lithologic logs, "as-installed" diagrams and descriptions of well development shall be submitted to the Department.

   A registered Florida land surveyor shall locate all wells and the coordinates shall be reported in accordance with Rule 62-701.510(3) (d) 1, F.A.C. Existing wells not used in the approved monitoring network for collection of samples or water elevation data shall be properly maintained or shall be properly abandoned in accordance with Rule 62-532.500(4), F.A.C. Appropriate well abandonment permits shall be obtained from the Northwest Florida Water Management District. *[Rule 62-701.510(3) (d) 1, F.A.C. and Rule 62-532.500(4), F.A.C.]*

3. The water-quality monitoring network shall consist of (47) ground water monitoring wells (3 -background, 24-detection, 10-compliance, 10-Piezometers) and 7-Surface Water Sampling Points. The surface water and groundwater monitoring well network is graphically represented on Attachment 2. The following designations shall be used for groundwater and surface water monitoring identification purposes in all future analysis reports:

   a. Ash Landfill

Well Name	Designation	Approximate Location	Test Site Number
MWB-1	Background	Unit 5	9106
MWC-3	Compliance	Unit 5	9107
MWC-4	Compliance	Unit 5	9108
GE-5D	Detection	Unit 5 (Gypsum Area 1)	9109
MWC-7	Compliance	Unit 5	9111
MWC-8	Compliance	Unit 5	9112
MWC-9	Compliance	Unit 5	8942

Well Name	Designation	Approximate Location	Test Site Number
MWB-2	Background	Unit 2	9113
GW-1S	Background	Unit 2 (Gypsum Area 2)	9114
MWI-1	Detection	Unit 2	9115
MWI-2	Detection	Unit 2	9116
GE-5S	Detection	Unit 2 (Gypsum Area 1)	9117
MWI-4	Detection	Unit 2	9119
MWC-10	Compliance	Unit 2	9118
MWC-11	Compliance	Unit 1	9121
MWC-12	Compliance	Unit 1	9122
MWP-1	Compliance	Unit 1	9123
MWP-2	Compliance	Unit 1	9124
MWP-3	Piezometer	Unit 1	9125
MWP-4	Piezometer	Unit 1	9126
MWP-5	Piezometer	Unit 1	9127
MWP-7	Piezometer	Unit 1	9129
MWP-8	Piezometer	Unit 2	9130
MWP-9	Piezometer	Unit 5	9131
MWP-10	Piezometer	Unit 2	9132
MWP-11	Piezometer	Unit 5	9133
MWP-12	Piezometer	Unit 2	9134
MWP-13	Piezometer	Unit 5	9135

b. Gypsum Storage Area 1 and Area 2

Well Name	Designation	Approximate Location	Test Site Number
GW-1S	Background	Unit 2, Gypsum Area 2	9114
GW-2S	Detection	Unit 2, Gypsum Area 2	22847
GW-3S	Detection	Unit 2, Gypsum Area 2	22849
GW-2D	Detection	Unit 5, Gypsum Area 2	22848
GW-3D	Detection	Unit 5, Gypsum Area 2	22850
GW-4S	Detection	Unit 2, Gypsum Area 2	22851
GW-4D	Detection	Unit 5, Gypsum Area 2	22852
GW-5S	Detection	Unit 2, Gypsum Area 2	22853
GW-5D	Detection	Unit 5, Gypsum Area 2	22854
GW-6S	Detection	Unit 2, Gypsum Area 2	22855
GW-6D	Detection	Unit 5, Gypsum Area 2	22856
GE-1S	Detection	Unit 2, Gypsum Area 1	22857
GE-1D	Detection	Unit 5, Gypsum Area 1	22858
GE-2S	Detection	Unit 2, Gypsum Area 1	22859
GE-2D	Detection	Unit 5, Gypsum Area 1	22860
GE-3S	Detection	Unit 2, Gypsum Area 1	22861
GE-3D	Detection	Unit 5, Gypsum Area 1	22862
GE-4S	Detection	Unit 2, Gypsum Area 1	22863
GE-4D	Detection	Unit 2, Gypsum Area 1	22864
GE-5S	Detection	Unit 2, Gypsum Area 1	9117
GE-5D	Detection	Unit 5, Gypsum Area 1	9109
GE-6S	Detection	Unit 2, Gypsum Area 1	22865
GE-6D	Detection	Unit 5, Gypsum Area 1	22866

c. Surface Water

Surface Water Name	Designation	Approximate Location	Test Site Number
SW-1	Upgradient	Approx 150 ft W of GW-1S	22867

Surface Water Name	Designation	Approximate Location	Test Site Number
SW-2	Down Gradient	Approx 225 ft SSW of GW-2S	22868
SW-3	Down Gradient	Approx 60 ft WSW of GW-3S	22869
SW-4	Down Gradient	Approx 430 ft WNW of GW-4S	22870
SW-5	Down Gradient	Approx 800 ft W of GE-1S	22871
SW-6	Down Gradient	Approx 980 ft NNW of GE-1S	22872
SW-7	Down Gradient	Approx 1,870 ft NE of GE-1S	22873
SW-8	Down Gradient	Approx 270 ft NE of GE-6S	22874

d. Construction of wells MWI-4 and MWC-7 shall be delayed until disposal of ash begins in Parcel 2 of the Bottom Ash Storage Area. Background well GW-1S shall be installed prior to storage of gypsum in Area 1 or Area 2. All other monitoring wells identified in Gypsum Area 1 shall be installed prior to storage of gypsum in Area 1 and all other monitoring wells identified in Gypsum Area 2 shall be installed prior to storage of gypsum in Area 2. *[Rule 62-520, F.A.C.]*

4. The water-quality monitoring parameters shall consist of groundwater and Surface Water parameters for each area. The following parameters shall be used for groundwater and surface water purposes in all future analysis reports:

a. All Ash Landfill groundwater monitoring wells shall be sampled semiannually for parameters listed below:

Field Parameters	Laboratory Parameters
Static water level in wells before purging	Aluminum, Total Recoverable
Specific conductivity	Arsenic, Total Recoverable
pH	Cadmium, Total Recoverable
Dissolved oxygen	Chloride
Turbidity	Chromium, Total Recoverable
Temperature	Copper, Total Recoverable
Oxidation –Reduction Potential	Iron, Total Recoverable
Colors and sheens (by observation)	Lead, Total Recoverable
	Manganese, Total Recoverable
	Mercury, Total Recoverable
	Magnesium, Total Recoverable
	Nickel, Total Recoverable
	Potassium, Total Recoverable
	Selenium, Total Recoverable
	Sodium, Total Recoverable
	Sulfates
	Zinc, Total Recoverable
	Total Dissolved Solids (TDS)
	Total Suspended Solids (TSS)

b. Compliance wells are exempt from compliance with the groundwater standard for arsenic. Surface Water Monitoring points shall meet the surface water standards as set forth in Chapter 62-302, F.A.C.

c. Monitoring wells are exempt from compliance with secondary drinking water standards unless the Department determines that compliance with one or more secondary standards is necessary to protect groundwater used or reasonably likely to be used as a potable water source. *[62-520.520(1), F.A.C.]*

d. All Gypsum Storage Area groundwater monitoring wells shall be sampled semiannually for parameters listed below:

Field parameters	Laboratory parameters
Static water level in wells before purging	Antimony
Specific conductivity	Arsenic
pH	Calcium
Dissolved oxygen	Magnesium
Turbidity	Mercury

Field parameters	**Laboratory parameters**
Temperature	Potassium
Oxidation –Reduction Potential	Selenium
Colors and sheens (by observation)	Sodium
	Thallium
	Bicarbonate Alkalinity
	Bromide (071870)
	Chloride
	Sulfates
	Total Dissolved Solids (TDS)

Water levels in each monitoring well shall be measured in a single day. During well sampling, water levels shall be measured on the sample day and recorded prior to evacuating the wells or collecting samples. Water level, top of well casing and land surface elevations at each well site, at a precision of plus or minus 0.01 feet NGVD, shall be reported on each analysis report. Prior to sampling, the field parameters of Rule 62-701.730(4) (b) 4, F.A.C., shall be stabilized from each well. Sampling and purging methods in the SOP's, as allowed in Chapter 62-160, F.A.C., must be used.

e. The surface water test sites shall be sampled semiannually for the parameters listed below.

Field Parameters	Laboratory Parameters
pH	Antimony
Turbidity	Arsenic
Temperature	Calcium
Specific Conductivity	Magnesium
Dissolved Oxygen	Mercury
Colors and Sheens (by observation)	Potassium
	Selenium
	Sodium
	Thallium
	Bicarbonate Alkalinity
	Bromide
	Chloride
	Sulfates
	Total Dissolved Solids (TDS)

All analyses of samples shall be conducted using approved State and Federal analytical methods with detection limits at or below the maximum allowable concentrations for all parameters, whenever possible.

Background water quality shall be sampled and analyzed in accordance with the provisions of Rule 62-701.510(6) (b), F.A.C. All background and detection wells shall be sampled and analyzed at least once prior to permit renewal for those parameters listed in Part III.B.4.a., c., and e. above.

A permit modification request to delete specific laboratory or field parameters must contain a demonstration that these parameters are not reasonably expected to be in or derived from the waste which was received or disposed of at the facility.

5. Rainfall at the site shall be measured on a daily basis and the results submitted with the semiannual reports.

6. An initial baseline sampling event of Gypsum Area 1 wells shall occur prior to placement of gypsum in Area 1 and an initial baseline sampling event of Gypsum Area 2 wells shall occur prior to placement of gypsum in Area 2. Semi-annual sampling for Gypsum Area 1 wells shall begin after gypsum disposal has occurred in Gypsum Area 1. Semi-annual sampling for Gypsum Area 2 wells shall begin after gypsum disposal has occurred in Gypsum Area 2. The results of each set of semiannual groundwater analyses shall be submitted under separate cover, no later than February 15 and August 15 each year, commencing with the August 15, 2009 report. *[Rule 62-701.730(4) (b), Rules 62-701.510(6) & (8), F.A.C., and permit application received December 6, 2006 and subsequent incompleteness information]*

The results of each set of semiannual ground water and surface water analyses may be submitted electronically on floppy diskettes or compact disc media readable by a Microsoft Windows computer. The data may be evaluated using ADaPT to conduct data quality review and compliance checking. Electronic laboratory shall may be submitted in a specific format called an Electronic Data Deliverable (EDD). The permittee shall include **Form 62-701.900(31)**, Water Quality Monitoring Certification, hereby adopted and incorporated by reference, with each report certifying that the laboratory results have been reviewed and approved by the permittee. Copies of this form are available from a local District Office or by writing to the Department of Environmental Protection, Solid Waste Section, MS 4565, 2600 Blair Stone 80 Road, Tallahassee, Florida 32399-2400. The website with information on ADaPT can be viewed using the following internet link: http://www.dep.state.fl.us/labs/dqa/adaptedms.htm.

All submittals in response to this specific condition shall be sent both to:

Florida Department of Environmental Protection
Northwest District Office
160 Governmental Center
Pensacola, Florida 32533

And to:

Florida Department of Environmental Protection
Solid Waste Section
2600 Blair Stone Road, MS 4565
Tallahassee, Florida, 32399-2400

The following data fields must be present in the data:	
Analytical Method	Analytical Result
Analytical Result Units	Appropriate Data Qualifiers (as listed in Chapter 62-160, F.A.C.)
Date of Analysis	Date of Preparation (if applicable)
Date of Sampling	Detection Limit of the Analysis
DOH Certification Number of the Laboratory	Facility Identification Number
Matrix (Aqueous, Drinking Water, Saline/Estuarine, or Solids)	Parameter Name (Name of the Compound Analyzed for/Test Performed)
	Test site ID

The submittal shall also include laboratory reports, Chain of Custody sheets, field data sheets, Water Sampling Logs (attached), ground water contour maps, a summary of any water quality standards or minimum criteria that are exceeded and any other required documents. These reports may be submitted electronically in portable document format (PDF) in lieu of a paper copy. If a specific document has a requirement to be signed and sealed, an original signed and sealed paper copy must also be submitted unless it is specifically permitted by law or rule to be signed electronically. *[Rules 62-701.510(6) and (8) (a), (b) and (d), F.A.C.]*

7. If at any time it is determined that any well in the routine monitoring system is not functioning properly and is not providing representative water quality samples, permittee shall have the wells evaluated, redeveloped, or replaced such that representative samples will be obtained during the next required routine sampling event.

   Any well which must be redeveloped should be surged with formation water or a surge block only. Wells which still produce sediment and high turbidity should be considered for replacement. Wells with high turbidity should be evaluated using the procedures called for in Rule 62-520.300(9), F.A.C.

   Any well requiring replacement shall be designed, installed and completed in accordance with the suggested practices of document ASTM D5092. *[Rule 62-701.510, F.A.C. and Rule 62-520, F.A.C.]*

8. Attachment 4, DEP Form 62-522.900(2), shall be reproduced by permittee and be used for water quality data submittals. A separate report is required for each sampling point. All water quality-monitoring reports required by this permit shall be submitted to:

   Department of Environmental Protection
   Northwest District Office
   Solid Waste Section
   160 Governmental Center
   Pensacola, Florida 32502

   The Department FDEP File Number and Facility Identification Number (WACS – 2216) for this facility shall be recorded on each report. The Test Site Number and Well Name shall be used on each report to identify the sampling point. *[Rule 62-701.510, F.A.C. and Rule 62-520, F.A.C.]*

9. A complete sampling record shall be provided for each sampling point. This record shall include:

   Water level; total depth of the well; volume of water in the well; volume of water removed; stabilization documentation including pH, conductivity, temperature, turbidity and dissolved oxygen; time interval of purging; time sample is taken; and device(s) used for purging (including discharge rate) and sampling.

   The permittee may wish to reproduce and use Attachment 6 (DEP-SOP-001/01 Form FD 9000-24) for reporting this information. Sampling methodologies must be capable of measuring concentrations of constituents at or below the maximum concentrations allowed, whenever possible. *[Rules 62-701.510 and 62-520, F.A.C.]*

10. In the event that water quality monitoring shows a violation of the applicable water quality standards, permittee shall arrange for a confirmation resampling within 30 days after permittee's receipt of laboratory results. In the event that permittee chooses not to conduct the reconfirmation sampling, the Department shall consider the initial analysis to be representative of the current water quality conditions at this facility. If the initial results demonstrates or the resampling confirms the ground water and/or surface water contamination, permittee shall notify the Department in writing within 14 days of this finding.

    Upon notification by the Department, permittee shall initiate evaluation monitoring in accordance with Rule 62-701.510(7), F.A.C.

11. If the parameters detected in the detection wells identified in Rule 62-701.510(7)(a), F.A.C., consist only of iron, aluminum, manganese, sulfates, or total dissolved solids (TDS), either individually or in any combination, then only the detected parameters are required to be monitored in the representative background wells, affected detection wells and down gradient compliance wells required in the section, rather than the parameters listed in Rule 62-701.510(8)(a), F.A.C., and Rule 62-701.510(8)(d), F.A.C. However, if the facility is unlined, the parameters specified in Rule 62-701.510(8)(a), F.A.C, shall also be analyzed for in the initial sampling event for the affected detection wells and down gradient compliance wells.

12. All water quality monitoring required by this permit shall be in accordance with Rules 62-520.300, F.A.C. and Rule 62-4.246, F.A.C., and shall be carried out under the requirements of DEP-SOP-001/01 (December 3, 2008) FS 2000 or applicable Standard Operating Procedures (SOPs) in accordance with Chapter 62-160, F.A.C. (effective April 9, 2002). Requirements for these plans may be obtained from the Department's Environmental Assessment Section, (850) 488-2796.

13. A technical report and a stabilization report required by Rule 62-701.620(6), F.A.C., signed and sealed by a professional geologist or professional engineer with experience in hydrogeologic investigations, shall be submitted to the Department every two and one-half years during the active life of the facility, and every five years during the long-term care periods. The report shall summarize and interpret the water quality monitoring results and water level measurements collected during the past two and one-half years. The report shall contain, at a minimum, the following::

a. Tabular displays of any data which shows that a monitoring parameter has been detected, and graphical displays of any leachate key indicator parameters detected (such as pH, specific conductance, TDS, TOC, sulfate, chloride, sodium and iron), including hydrographs for all monitor wells.

b. Trend analyses of any monitoring parameters consistently detected.

c. Comparisons among shallow, middle and deep zone wells.

d. Comparisons between background water quality and the water quality in detection and compliance wells.

e. Correlations between related parameters such as total dissolved solids and specific conductance.

f. Discussion of erratic and/or poorly correlated data.

g. An interpretation of the ground water contour maps, including an evaluation of ground water flow rates.

h. An evaluation of the adequacy of the water quality monitoring frequency and sampling locations based upon site conditions

The technical report shall be submitted under separate cover with the permit renewal application, no later than the date of the permit expiration, November 13, 2010. *[Rule 62-701.510(9) (b), F.A.C.]*

14. If water-quality monitoring demonstrates contaminants are detected and confirmed in compliance wells or surface water sampling points in concentrations which exceed both background levels and Department water quality standards or criteria, the permittee shall notify the Department within 14 days of this finding and shall initiate corrective actions. Evaluation monitoring shall continue according to the requirements of Rule 62-701.510 (7) (a), F.A.C.

The permittee shall initiate and complete corrective actions in accordance with Chapter 62-780, F.A.C. within the manner and timeframes specified therein and provide a site assessment report (SAR) in accordance with Rule 62-780.600, F.A.C. that meets the objectives of said Rule within the manner and timeframes specified therein. *[Rule 62-701.510(7)(b)2, F.A.C]*

IV. ADDITIONAL LAND APPLICATION REQUIREMENTS

This section is not applicable to the facility.

V. OPERATION AND MAINTENANCE REQUIREMENTS

1. During the period of operation authorized by this permit, the wastewater facilities shall be operated under the supervision of a person who is qualified by formal training and/or practical experience in the field of water pollution control. *[62-620.320(6)]*

2. The permittee shall maintain the following records and make them available for inspection on the site of the permitted facility.

   a. Records of all compliance monitoring information, including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation, including, if applicable, a copy of the laboratory certification showing the certification number of the laboratory, for at least three years from the date the sample or measurement was taken;

   b. Copies of all reports required by the permit for at least three years from the date the report was prepared;

   c. Records of all data, including reports and documents, used to complete the application for the permit for at least three years from the date the application was filed:

   d. A copy of the current permit;

   e. A copy of any required record drawings; and

   f. Copies of the logs and schedules showing plant operations and equipment maintenance for three years from the date of the logs or schedules.

[62-620.350]

VI. SCHEDULES

1. The following improvement actions shall be completed according to the following schedule. The Best Management Practices/Pollution Prevention (BMP3) Plan shall be prepared and implemented in accordance with Part VIII of this permit:

Action Item	Completion Date
1. Continue implementing the existing BMP3 Plan	Issuance date of permit

[62-620.320(6)]

2. If the permittee wishes to continue operation of this wastewater facility after the expiration date of this permit, the permittee shall submit an application for renewal no later than one-hundred and eighty days (180) prior to the expiration date of this permit. Application shall be made using the appropriate forms listed in Rule 62-620.910, F.A.C., including submittal of the appropriate processing fee set forth in Rule 62-4.050, F.A.C. *[62-620.335(1) and (2)]*

3. Within six months of the effective date of this permit, the permittee shall schedule a meeting with the Department to discuss the contents of the aquatic organism return plan in accordance with Condition I.A.12 and shall submit the plan to the Department within 12 months of the effective date of this permit. The plan shall be implemented within 24 months subsequent to approval by the Department.

4. The permittee shall submit technical reports in accordance with Condition III.13.

VII. BEST MANAGEMENT PRACTICES/STORMWATER POLLUTION PREVENTION PLANS

1. General Conditions

   In accordance with Section 304(e) and 402(a)(2) of the Clean Water Act (CWA) as amended, 33 U.S.C. §§ 1251 et seq., and the Pollution Prevention Act of 1990, 42 U.S.C. §§ 13101-13109, the permittee must develop and implement a plan for utilizing practices incorporating pollution prevention measures. References to be considered in developing the plan are "Criteria and Standards for Best Management Practices Authorized Under Section 304(e) of the Act," found at 40 CFR 122.44 Subpart K and the Storm Water Management Industrial Activities Guidance Manual, EPA/833-R92-002 and other EPA documents relating to Best Management Practice guidance.

   a. Definitions
      (1) The term "pollutants" refers to conventional, non-conventional and toxic pollutants.
      (2) Conventional pollutants are: biochemical oxygen demand (BOD), suspended solids, pH, fecal coliform bacteria and oil & grease.
      (3) Non-conventional pollutants are those which are not defined as conventional or toxic.
      (4) Toxic pollutants include, but are not limited to: (a) any toxic substance listed in Section 307(a)(1) of the CWA, any hazardous substance listed in Section 311 of the CWA, or chemical listed in Section 313(c) of the Superfund Amendments and Reauthorization Act of 1986; and (b) any substance (that is not also a conventional or non-conventional pollutant except ammonia) for which EPA has published an acute or chronic toxicity criterion.
      (5) "Significant Materials" is defined as raw materials; fuels; materials such as solvents and detergents; hazardous substances designated under Section 101(14) of CERCLA; and any chemical the facility is required to report pursuant to EPCRA. Section 313; fertilizers; pesticides; and waste products such as ashes, slag and sludge.
      (6) "Pollution prevention" and "waste minimization" refer to the first two categories of EPA's preferred hazardous waste management strategy: first, source reduction and then, recycling.
      (7) "Recycle/Reuse" is defined as the minimization of waste generation by recovering and reprocessing usable products that might otherwise become waste; or the reuse or reprocessing of usable waste products in place

of the original stock, or for other purposes such as material recovery, material regeneration or energy production.

(8) "Source reduction" means any practice which: (a) reduces the amount of any pollutant entering a waste stream or otherwise released into the environment (including fugitive emissions) prior to recycling, treatment or disposal; and (b) reduces the hazards to public health and the environment associated with the release of such pollutant. The term includes equipment or technology modifications, process or procedure modifications, reformulation or redesign of products, substitution of raw materials, and improvements in housekeeping, maintenance, training, or inventory control. It does not include any practice which alters the physical, chemical, or biological characteristics or the volume of a pollutant through a process or activity which itself is not integral to, or previously considered necessary for, the production of a product or the providing of a service.

(9) "BMP3" means a Best Management Practices Pollution Prevention Plan incorporating the requirements of 40 CFR § 125, Subpart K, plus pollution prevention techniques, except where other existing programs are deemed equivalent by the permittee. The permittee shall certify the equivalency of the other referenced programs.

(10) The term "material" refers to chemicals or chemical products used in any plant operation (i.e., caustic soda, hydrazine, degreasing agents, paint solvents, etc.). It does not include lumber, boxes, packing materials, etc.

2. Best Management Practices/Pollution Prevention Plan

The permittee shall develop and implement a BMP3 plan for the facility, which is the source of wastewater and storm water discharges, covered by this permit. The plan shall be directed toward reducing those pollutants of concern which discharge to surface waters and shall be prepared in accordance with good engineering and good housekeeping practices. For the purposes of this permit, pollutants of concern shall be limited to toxic pollutants, as defined above, known to the discharger. The plan shall address all activities which could or do contribute these pollutants to the surface water discharge, including process, treatment, and ancillary activities.

a. Signatory Authority & Management Responsibilities

The BMP3 plan shall be signed by permittee or their duly authorized representative in accordance with rule 62-620.305(2)(a) and (b). The BMP3 plan shall be reviewed by plant environmental/engineering staff and plant manager. Where required by Chapter 471-(P.E.) or Chapter 492 (P.G.) Florida Statutes, applicable portions of the BMP3 plant shall be signed and sealed by the professional(s) who prepared them.

A copy of the plant shall be retained at the facility and shall be made available to the permit issuing authority upon request.

The BMP3 plan shall contain a written statement from corporate or plant management indicating management's commitment to the goals of the BMP3 program. Such statements shall be publicized or made known to all facility employees. Management shall also provide training for the individuals responsible for implementing the BMP3 plan.

b. BMP3 Plan Requirements

(1) Name & description of facility, a map illustrating the location of the facility & adjacent receiving waters, and other maps, plot plans or drawings, as necessary;

(2) Overall objectives (both short-term and long-term) and scope of the plan, specific reduction goals for pollutants, anticipated dates of achievement of reduction, and a description of means for achieving each reduction goal;

(3) A description of procedures relative to spill prevention, control & countermeasures and a description of measures employed to prevent storm water contamination;

(4) A description of practices involving preventive maintenance, housekeeping, recordkeeping, inspections, and plant security; and

(5) The description of a waste minimization assessment performed in accordance with the conditions outlined in condition c below, results of the assessment, and a schedule for implementation of specific waste reduction practices.

c. Waste Minimization Assessment

The permittee is encouraged but not required to conduct A waste minimization assessment (WMA) for this facility to determine actions that could be taken to reduce waste loading and chemical losses to all wastewater and/or storm water streams as described in Part VII.D.2 of this permit.

If the permittee elects to develop and implement a WMA, information on plan components can be obtained forms the Department's Industrial Wastewater website, or from:

Florida Department of Environmental Protection
Industrial Wastewater Section, Mail Station 3545
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
(850) 245-8589
(850) 245-8669 – Fax

d. Best Management Practices & Pollution Prevention Committee Recommended:

A Best Management Practices Committee (Committee) should be established to direct or assist in the implementation of the BMP3 plan. The Committee should be comprised of individuals within the plant organization who are responsible for developing the BMP3 plan and assisting the plant manager in its implementation, monitoring of success, and revision. The activities and responsibilities of the Committee should address all aspects of the facility's BMP3 plan. The scope of responsibilities of the Committee should be described in the plan.

e. Employee Training

Employee training programs shall inform personnel at all levels of responsibility of the components & goals of the BMP3 plan and shall describe employee responsibilities for implementing the plan. Training shall address topics such as good housekeeping, materials management, record keeping & reporting, spill prevention & response, as well as specific waste reduction practices to be employed. Training should also disclose how individual employees may contribute suggestions concerning the BMP3 plan or suggestions regarding Pollution Prevention. The plan shall identify periodic dates for such training.

f. Plan Development & Implementation

The BMP3 plan shall be developed and implemented 6 months after the effective date of this permit, unless any later dates are specified in this permit. Any portion of the WMA which is ongoing at the time of development or implementation shall be described in the plan. Any waste reduction practice which is recommended for implementation over a period of time shall be identified in the plan, including a schedule for its implementation.

g. Submission of Plan Summary & Progress/Update Reports

(1) Plan Summary: Not later than 2 years after the effective date of the permit, a summary of the BMP3 plan shall be developed and maintained at the facility and made available to the permit issuing authority upon request. The summary should include the following: a brief description of the plan, its implementation process, schedules for implementing identified waste reduction practices, and a list of all waste reduction practices being employed at the facility. The results of waste minimization assessment studies already completed as well as any scheduled or ongoing WMA studies shall be discussed.

(2) Progress/Update Reports: Annually thereafter for the duration of the permit progress/update reports documenting implementation of the plan shall be maintained at the facility and made available to the permit issuing authority upon request. The reports shall discuss whether or not implementation schedules were met and revise any schedules, as necessary. The plan shall also be updated as necessary and the attainment or progress made toward specific pollutant reduction targets documented. Results of any ongoing WMA studies as well as any additional schedules for implementation of waste reduction practices shall be included.

(3) A timetable for the various plan requirements follows:

Timetable for BMP3 Plan Requirements:

REQUIREMENT	TIME FROM EFFECTIVE DATE OF THIS PERMIT
Progress/Update Reports	3 years, and then annually thereafter

The permittee shall maintain the plan and subsequent reports at the facility and shall make the plan available to the Department upon request.

h. Plan Review & Modification

If following review by the Department, the BMP3 plan is determined insufficient, the permittee will be notified that the BMP3 plan does not meet one or more of the minimum requirements of this Part. Upon such notification from the Department, the permittee shall amend the plan and shall submit to the Department a written certification that the requested changes have been made. Unless otherwise provided by the Department, the permittee shall have 30 days after such notification to make the changes necessary.

The permittee shall modify the BMP3 plan whenever there is a change in design, construction, operation, or maintenance, which has a significant effect on the potential for the discharge of pollutants to waters of the State or if the plan proves to be ineffective in achieving the general objectives of reducing pollutants in wastewater or storm water discharges. Modifications to the plan may be reviewed by the Department in the same manner as described above.

VIII. OTHER SPECIFIC CONDITIONS

A. Specific Conditions Applicable to All Permits

1. Where required by Chapter 471 or Chapter 492, F.S., applicable portions of reports that must be submitted under this permit shall be signed and sealed by a professional engineer or a professional geologist, as appropriate. *[62-620.310(4)]*

2. Drawings, plans, documents or specifications submitted by the permittee, not attached hereto, but retained on file at the Department's Northwest District Office, are made a part hereof.

3. This permit satisfies Industrial Wastewater program permitting requirements only and does not authorize operation of this facility prior to obtaining any other permits required by local, state or federal agencies.

4. The permittee shall provide verbal notice to the Department's Northwest District Office as soon as practical after discovery of a sinkhole or other karst feature within an area for the management or application of wastewater, or wastewater sludges. The permittee shall immediately implement measures appropriate to control the entry of contaminants, and shall detail these measures to the Department's Northwest District Office in a written report within 7 days of the sinkhole discovery. *[62-620.320(6)]*

B. Specific Conditions Related to Existing Manufacturing, Commercial, Mining, and Silviculture Wastewater Facilities or Activities

1. Existing manufacturing, commercial, mining, and silvicultural wastewater facilities or activities that discharge into surface waters shall notify the Department as soon as they know or have reason to believe:

   a. That any activity has occurred or will occur which would result in the discharge, on a routine or frequent basis, of any toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following levels;
      (1) One hundred micrograms per liter,
      (2) Two hundred micrograms per liter for acrolein and acrylonitrile; five hundred micrograms per liter for 2, 4-dinitrophenol and for 2-methyl-4, 6-dinitrophenol; and one milligram per liter for antimony, or
      (3) Five times the maximum concentration value reported for that pollutant in the permit application; or

   b. That any activity has occurred or will occur which would result in any discharge, on a non-routine or infrequent basis, of a toxic pollutant which is not limited in the permit, if that discharge will exceed the highest of the following levels;
      (1) Five hundred micrograms per liter,
      (2) One milligram per liter for antimony, or
      (3) Ten times the maximum concentration value reported for that pollutant in the permit application.

   [62-620.625(1)]

C. Impoundment Design, Construction, Operation, and Maintenance

1. All ash impoundments used to hold or treat wastewater and other associated wastes shall be operated and maintained to prevent the discharge of pollutants to waters of the State, except as authorized under this permit.

2. Operation and maintenance of any ash impoundment shall be in accordance with all applicable State regulations. When practicable, piezometers or other instrumentation shall be used as a means to aid monitoring of impoundment integrity.

D. Impoundment Integrity Inspections

1. No later than January 31, 2011, and annually thereafter, all impoundments shall be inspected by qualified personnel with knowledge and training in impoundment integrity. Annual inspections shall include observations of dike and toe areas for erosion, cracks or bulges, seepage, wet or soft soil, changes in geometry, the depth and elevation of the impounded water, sediment or slurry, freeboard, changes in vegetation such as overly lush, dead or unnaturally tilted vegetation, and any other changes which may indicate a potential compromise to impoundment integrity.

2. Within 30 days after the annual inspection, a qualified, responsible officer shall certify to the Department that no breaches or structural defects resulting in the discharges to surface waters of the State and that no changes were observed which may indicate a potential compromise to impoundment integrity during the previous calendar year.

   The certification shall also include a statement that the ash pond provides the necessary minimum wet weather detention volume to contain the combined volume for all direct rainfall and all rainfall runoff to the pond resulting from the 10-year, 24-hour rainfall event and maximum dry weather plant waste flows which could occur during a 24-hour period.

3. The permittee shall conduct follow-up inspections within 7 days after large or extended rain events (i.e., 25-year, 24-hour precipitation event).

4. In the event that a critical condition in the ash impoundment, such as the conditions listed below, is suspected that may result in a potential discharge to surface waters of the State, the permittee shall notify the Department within twenty-four (24) hours of becoming aware of the situation and provide a proposed course of corrective action and implementation schedule within fifteen (15) days from the time existence of the critical condition is confirmed and the Department was notified.

   Critical conditions include observed changes such as concentrated seepage on the downstream of the slope, at the top of the slope, or downstream from the toe of the slope, evidence of slope instability including sloughing, bulging, or heaving of the downstream slope, or subsidence of the impoundment slope or crest, cracking of surface on the crest or either face of the impoundment, or general or concentrated seepage in the vicinity of or around any conduit through the impoundment may be signs imminent impoundment failure and should be addressed immediately.

E. Reporting and Recordkeeping Requirements for Impoundments

1. The summarized findings of all monitoring activities, inspections, and corrective actions pertaining to the impoundment integrity, and operation and maintenance of all impoundments shall be documented and kept on-site in accordance with permit Condition V.3, and made available to Department inspectors upon request.

2. Starting with the issuance of this permit, all pertinent impoundment permits, design, construction, operation, and maintenance information, including but not limited to: plans, geotechnical and structural integrity studies, copies of permits, associated certifications by qualified, Florida-registered professional engineer, and regulatory approvals, shall be kept on site in accordance with permit Condition V.3 and made available to Department inspectors upon request.

F. Duty to Reapply

1. The permittee is not authorized to discharge to waters of the State after the expiration date of this permit, unless:

   a. the permittee has applied for renewal of this permit at least 180 days before the expiration date (**July, 31, 2015**) using the appropriate forms listed in Rule 62-620.910, F.A.C., and in the manner established in the Department of Environmental Protection Guide to Permitting Wastewater Facilities or Activities Under Chapter 62-620, F.A.C., including submittal of the appropriate processing fee set forth in Rule 62-4.050, F.A.C.; or

   b. the permittee has made complete the application for renewal of this permit before the permit expiration date.

   [62-620.335(1)-(4), F.A.C.]

2. When publishing Notice of Draft and Notice of Intent in accordance with Rules 62-110.106 and 62-620.550, F.A.C., the permittee shall publish the notice at its expense in a newspaper of general circulation in the county or counties in which the activity is to take place either

   a. Within thirty days after the permittee has received a notice; or
   b. Within thirty days after final agency action.

   Failure to publish a notice is a violation of this permit.

G. Reopener Clauses

1. The permit shall be revised, or alternatively, revoked and reissued in accordance with the provisions contained in Rules 62-620.325 and 62-620.345 F.A.C., if applicable, or to comply with any applicable effluent standard or limitation issued or approved under Sections 301(b)(2)(C) and (D), 304(b)(2) and 307(a)(2) of the Clean Water Act (the Act), as amended, if the effluent standards, limitations, or water quality standards so issued or approved:

   a. Contains different conditions or is otherwise more stringent than any condition in the permit/or;
   b. Controls any pollutant not addressed in the permit.

   The permit as revised or reissued under this paragraph shall contain any other requirements then applicable.

2. The permit may be reopened to adjust effluent limitations or monitoring requirements should future Water Quality Based Effluent Limitation determinations, water quality studies, DEP approved changes in water quality standards, EPA established Total Maximum Daily Loads (TMDLs), or other information show a need for a different limitation, monitoring requirement, or more stringent requirements or any applicable standards pertaining to the operation and maintenance of coal combustion waste impoundments.

3. The Department or EPA may develop a TMDL during the life of the permit. Once a TMDL has been established and adopted by rule, the Department shall revise this permit to incorporate the final findings of the TMDL.

4. The permit shall be reopened for revision as appropriate to address new information that was not available at the time of this permit issuance or to comply with requirements of new regulations, standards, or judicial decisions relating to CWA 316(b).

IX. GENERAL CONDITIONS

1. The terms, conditions, requirements, limitations and restrictions set forth in this permit are binding and enforceable pursuant to Chapter 403, Florida Statutes. Any permit noncompliance constitutes a violation of Chapter 403, Florida Statutes, and is grounds for enforcement action, permit termination, permit revocation and reissuance, or permit revision. *[62-620.610(1)]*

2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviations from the approved drawings, exhibits, specifications or conditions of this permit constitutes grounds for revocation and enforcement action by the Department. *[62-620.610(2)]*

3. As provided in subsection 403.087(7), F.S., the issuance of this permit does not convey any vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor authorize any infringement of federal, state, or local laws or regulations. This permit is not a waiver of or approval of any other Department permit or authorization that may be required for other aspects of the total project which are not addressed in this permit. *[62-620.610(3)]*

4. This permit conveys no title to land or water, does not constitute state recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title. *[62-620.610(4)]*

5. This permit does not relieve the permittee from liability and penalties for harm or injury to human health or welfare, animal or plant life, or property caused by the construction or operation of this permitted source; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department. The permittee shall take all reasonable steps to minimize or prevent any discharge, reuse of reclaimed water, or residuals use or disposal in violation of this permit which has a reasonable likelihood of adversely affecting human health or the environment. It shall not be a defense for a permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit. *[62-620.610(5)]*

6. If the permittee wishes to continue an activity regulated by this permit after its expiration date, the permittee shall apply for and obtain a new permit. *[62-620.610(6)]*

7. The permittee shall at all times properly operate and maintain the facility and systems of treatment and control, and related appurtenances, that are installed and used by the permittee to achieve compliance with the conditions of this permit. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to maintain or achieve compliance with the conditions of the permit. *[62-620.610(7)]*

8. This permit may be modified, revoked and reissued, or terminated for cause. The filing of a request by the permittee for a permit revision, revocation and reissuance, or termination, or a notification of planned changes or anticipated noncompliance does not stay any permit condition. *[62-620.610(8)]*

9. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, including an authorized representative of the Department and authorized EPA personnel, when applicable, upon presentation of credentials or other documents as may be required by law, and at reasonable times, depending upon the nature of the concern being investigated, to:

   a. Enter upon the permittee's premises where a regulated facility, system, or activity is located or conducted, or where records shall be kept under the conditions of this permit;

   b. Have access to and copy any records that shall be kept under the conditions of this permit;

   c. Inspect the facilities, equipment, practices, or operations regulated or required under this permit; and

   d. Sample or monitor any substances or parameters at any location necessary to assure compliance with this permit or Department rules.

   [62-620.610(9)]

10. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data, and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except as such use is proscribed by Section 403.111, F.S., or Rule 62-620.302, F.A.C. Such evidence shall only be used to the extent that it is consistent with the Florida Rules of Civil Procedure and applicable evidentiary rules. *[62-620.610(10)]*

11. When requested by the Department, the permittee shall within a reasonable time provide any information required by law which is needed to determine whether there is cause for revising, revoking and reissuing, or terminating this permit, or to determine compliance with the permit. The permittee shall also provide to the Department upon request copies of records required by this permit to be kept. If the permittee becomes aware of relevant facts that

were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be promptly submitted or corrections promptly reported to the Department. *[62-620.610(11)]*

12. Unless specifically stated otherwise in Department rules, the permittee, in accepting this permit, agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance; provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules. A reasonable time for compliance with a new or amended surface water quality standard, other than those standards addressed in Rule 62-302.500, F.A.C., shall include a reasonable time to obtain or be denied a mixing zone for the new or amended standard. *[62-620.610(12)]*

13. The permittee, in accepting this permit, agrees to pay the applicable regulatory program and surveillance fee in accordance with Rule 62-4.052, F.A.C. *[62-620.610(13)]*

14. This permit is transferable only upon Department approval in accordance with Rule 62-620.340, F.A.C. The permittee shall be liable for any noncompliance of the permitted activity until the transfer is approved by the Department. *[62-620.610(14)]*

15. The permittee shall give the Department written notice at least 60 days before inactivation or abandonment of a wastewater facility or activity and shall specify what steps will be taken to safeguard public health and safety during and following inactivation or abandonment. *[62-620.610(15)]*

16. The permittee shall apply for a revision to the Department permit in accordance with Rules 62-620.300, F.A.C., and the Department of Environmental Protection Guide to Permitting Wastewater Facilities or Activities Under Chapter 62-620, F.A.C., at least 90 days before construction of any planned substantial modifications to the permitted facility is to commence or with Rule 62-620.325(2), F.A.C., for minor modifications to the permitted facility. A revised permit shall be obtained before construction begins except as provided in Rule 62-620.300, F.A.C. *[62-620.610(16)]*

17. The permittee shall give advance notice to the Department of any planned changes in the permitted facility or activity which may result in noncompliance with permit requirements. The permittee shall be responsible for any and all damages which may result from the changes and may be subject to enforcement action by the Department for penalties or revocation of this permit. The notice shall include the following information:

    a. A description of the anticipated noncompliance;
    b. The period of the anticipated noncompliance, including dates and times; and
    c. Steps being taken to prevent future occurrence of the noncompliance.

    [62-620.610(17)]

18. Sampling and monitoring data shall be collected and analyzed in accordance with Rule 62-4.246 and Chapters 62-160, 62-601, and 62-610, F.A.C., and 40 CFR 136, as appropriate.

    a. Monitoring results shall be reported at the intervals specified elsewhere in this permit and shall be reported on a Discharge Monitoring Report (DMR), DEP Form 62-620.910(10), or as specified elsewhere in the permit.

    b. If the permittee monitors any contaminant more frequently than required by the permit, using Department approved test procedures, the results of this monitoring shall be included in the calculation and reporting of the data submitted in the DMR.

    c. Calculations for all limitations which require averaging of measurements shall use an arithmetic mean unless otherwise specified in this permit.

    d. Except as specifically provided in Rule 62-160.300, F.A.C., any laboratory test required by this permit shall be performed by a laboratory that has been certified by the Department of Health Environmental Laboratory Certification Program (DOH ELCP). Such certification shall be for the matrix, test method and analyte(s) being measured to comply with this permit. For domestic wastewater facilities, testing for parameters listed in Rule 62-160.300(4), F.A.C., shall be conducted under the direction of a certified operator.

    e. Field activities including on-site tests and sample collection shall follow the applicable standard operating procedures described in DEP-SOP-001/01 adopted by reference in Chapter 62-160, F.A.C.

f. Alternate field procedures and laboratory methods may be used where they have been approved in accordance with Rules 62-160.220, and 62-160.330, F.A.C.

[62-620.610(18)]

19. Reports of compliance or noncompliance with, or any progress reports on, interim and final requirements contained in any compliance schedule detailed elsewhere in this permit shall be submitted no later than 14 days following each schedule date. *[62-620.610(19)]*

20. The permittee shall report to the Department's Northwest District Office any noncompliance which may endanger health or the environment. Any information shall be provided orally within 24 hours from the time the permittee becomes aware of the circumstances. A written submission shall also be provided within five days of the time the permittee becomes aware of the circumstances. The written submission shall contain: a description of the noncompliance and its cause; the period of noncompliance including exact dates and time, and if the noncompliance has not been corrected, the anticipated time it is expected to continue; and steps taken or planned to reduce, eliminate, and prevent recurrence of the noncompliance.

   a. The following shall be included as information which must be reported within 24 hours under this condition:
      (1) Any unanticipated bypass which causes any reclaimed water or effluent to exceed any permit limitation or results in an unpermitted discharge,
      (2) Any upset which causes any reclaimed water or the effluent to exceed any limitation in the permit,
      (3) Violation of a maximum daily discharge limitation for any of the pollutants specifically listed in the permit for such notice, and
      (4) Any unauthorized discharge to surface or ground waters.

   b. Oral reports as required by this subsection shall be provided as follows:
      (1) For unauthorized releases or spills of treated or untreated wastewater reported pursuant to subparagraph (a)4. that are in excess of 1,000 gallons per incident, or where information indicates that public health or the environment will be endangered, oral reports shall be provided to the STATE WARNING POINT TOLL FREE NUMBER (800) 320-0519, as soon as practical, but no later than 24 hours from the time the permittee becomes aware of the discharge. The permittee, to the extent known, shall provide the following information to the State Warning Point:
         (a) Name, address, and telephone number of person reporting;
         (b) Name, address, and telephone number of permittee or responsible person for the discharge;
         (c) Date and time of the discharge and status of discharge (ongoing or ceased);
         (d) Characteristics of the wastewater spilled or released (untreated or treated, industrial or domestic wastewater);
         (e) Estimated amount of the discharge;
         (f) Location or address of the discharge;
         (g) Source and cause of the discharge;
         (h) Whether the discharge was contained on-site, and cleanup actions taken to date;
         (i) Description of area affected by the discharge, including name of water body affected, if any; and
         (j) Other persons or agencies contacted.
      (2) Oral reports, not otherwise required to be provided pursuant to subparagraph b.1 above, shall be provided to the Department's Northwest District Office within 24 hours from the time the permittee becomes aware of the circumstances.

   c. If the oral report has been received within 24 hours, the noncompliance has been corrected, and the noncompliance did not endanger health or the environment, the Department's Northwest District Office shall waive the written report.

[62-620.610(20)]

21. The permittee shall report all instances of noncompliance not reported under Permit Conditions IX. 17, 18 or 19 of this permit at the time monitoring reports are submitted. This report shall contain the same information required by Permit Condition IX.20 of this permit. *[62-620.610(21)]*

22. Bypass Provisions.

a. "Bypass" means the intentional diversion of waste streams from any portion of a treatment works.

b. Bypass is prohibited, and the Department may take enforcement action against a permittee for bypass, unless the permittee affirmatively demonstrates that:
   (1) Bypass was unavoidable to prevent loss of life, personal injury, or severe property damage; and
   (2) There were no feasible alternatives to the bypass, such as the use of auxiliary treatment facilities, retention of untreated wastes, or maintenance during normal periods of equipment downtime. This condition is not satisfied if adequate back-up equipment should have been installed in the exercise of reasonable engineering judgment to prevent a bypass which occurred during normal periods of equipment downtime or preventive maintenance; and
   (3) The permittee submitted notices as required under Permit Condition IX. 22. b. of this permit.

c. If the permittee knows in advance of the need for a bypass, it shall submit prior notice to the Department, if possible at least 10 days before the date of the bypass. The permittee shall submit notice of an unanticipated bypass within 24 hours of learning about the bypass as required in Permit Condition IX. 20. of this permit. A notice shall include a description of the bypass and its cause; the period of the bypass, including exact dates and times; if the bypass has not been corrected, the anticipated time it is expected to continue; and the steps taken or planned to reduce, eliminate, and prevent recurrence of the bypass.

d. The Department shall approve an anticipated bypass, after considering its adverse effect, if the permittee demonstrates that it will meet the three conditions listed in Permit Condition IX. 22. a. 1 through 3 of this permit.

e. A permittee may allow any bypass to occur which does not cause reclaimed water or effluent limitations to be exceeded if it is for essential maintenance to assure efficient operation. These bypasses are not subject to the provisions of Permit Condition IX. 22. b. through d. of this permit.

[62-620.610(22)]

23. Upset Provisions.

a. "Upset" means an exceptional incident in which there is unintentional and temporary noncompliance with technology-based effluent limitations because of factors beyond the reasonable control of the permittee.
   (1) An upset does not include noncompliance caused by operational error, improperly designed treatment facilities, inadequate treatment facilities, lack of preventive maintenance, careless or improper operation.
   (2) An upset constitutes an affirmative defense to an action brought for noncompliance with technology based permit effluent limitations if the requirements of upset provisions of Rule 62-620.610, F.A.C., are met.

b. A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed contemporaneous operating logs, or other relevant evidence that:
   (1) An upset occurred and that the permittee can identify the cause(s) of the upset;
   (2) The permitted facility was at the time being properly operated;
   (3) The permittee submitted notice of the upset as required in Permit Condition IX.5. of this permit; and
   (4) The permittee complied with any remedial measures required under Permit Condition IX. 5. of this permit.

c. In any enforcement proceeding, the burden of proof for establishing the occurrence of an upset rests with the permittee.

d. Before an enforcement proceeding is instituted, no representation made during the Department review of a claim that noncompliance was caused by an upset is final agency action subject to judicial review.

[62-620.610(23)]

Executed in Tallahassee, Florida.

STATE OF FLORIDA DEPARTMENTOF
ENVIRONMENTAL PROTECTION

Director
Division of Water Resource Management
2600 Blair Stone Road
Tallahassee, Florida 32399-2400
(850) 245-8336

Attached:

Attachment 1: Final Discharge Monitoring Report
Attachment 2: DEP Form 62-701.900(31) – Water Quality Monitoring Certification
Attachment 3: DEP Form 9000-24 – Ground Water Sampling Log

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME:	Gulf Power Company	PERMIT NUMBER:	FL0002275-013-IW1S		
MAILING ADDRESS:	One Energy Place Pensacola, Florida 32520				
		LIMIT:	Interim	REPORT FREQUENCY:	Quarterly
		CLASS SIZE:	MA	PROGRAM:	Industrial
FACILITY:	Crist Electric Generating Plant	MONITORING GROUP NUMBER:	D-010		
LOCATION:	Ten Mile Road Pensacola, FL	MONITORING GROUP DESCRIPTION:	Combined Main Plant Discharge (Formerly D-001)		
		RE-SUBMITTED DMR:	☐		
		NO DISCHARGE FROM SITE:	☐		
COUNTY:	Escambia	MONITORING PERIOD From:	____________	To:	____________
OFFICE:	Northwest District				

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex	Frequency of Analysis	Sample Type
TRO-Discharge Time	Sample Measurement										
PARM Code 04223 1 Mon. Site No. EFF-1	Permit Requirement					120 (Mo.Avg.)	120 (Day.Max.)	min/day		Quarterly	Meter
Oil and Grease	Sample Measurement										
PARM Code 00556 1 Mon. Site No. EFF-1	Permit Requirement					5.0 (Mo.Avg.)	5.0 (Day.Max.)	mg/L		Quarterly	Grab
Arsenic, Total Recoverable (effluent)	Sample Measurement										
PARM Code 00978 1 Mon. Site No. EFF-1	Permit Requirement					50.0[1] (Mo.Avg.)	50.0[1] (Day.Max.)	ug/L		Quarterly	24-hr TPC
Arsenic, Total Recoverable (Intake)	Sample Measurement										
PARM Code 00978 Q Mon Site No. INT-1	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ug/L		Quarterly	24-hr TPC
Cadmium, Total Recoverable (effluent)	Sample Measurement										
PARM Code 01113 1 Mon. Site No. EFF-1	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ug/L		Quarterly	24-hr TPC
Cadmium, Total Recoverable (calculated limit)	Sample Measurement										
PARM Code 01113 Q Mon. Site No. EFF-1	Permit Requirement					Report[2] (Mo.Avg.)	Report[2] (Day.Max.)	ug/L		Quarterly	Calculated
Cadmium, Total Recoverable (effluent minus calculated limit)	Sample Measurement										
PARM Code 01113 R Mon. Site No. EFF-1	Permit Requirement					0.0 (Mo.Avg.)	0.0 (Day.Max.)	ug/L		Quarterly	Calculated

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO.	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

[1] See Permit Condition I.A.8. If the concentration of the intake is greater than 50.0 ug/L, the intake concentration should be used as the effluent limit.

[2] See Permit Conditions I.A.7 & I.A.8. If the concentration of the intake is greater than the limit calculated in Condition I.A.7, the intake concentration should be used as the effluent limit.

Docket No. 110007-EI
Plant Crist NPDES Permit
Exhibit JOV-1, Page 38 of 63

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: Crist Electric Generating Plant MONITORING GROUP NUMBER: D-010 PERMIT NUMBER: FL0002275-013-IW1S

MONITORING PERIOD From: ____________ To: ____________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Cadmium, Total Recoverable (Intake)	Sample Measurement										
PARM Code 01113 S Mon. Site No. INT-1	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ug/L		Quarterly	24-hr TPC
Chromium, Hexavalent Total Recoverable (Effluent)	Sample Measurement										
PARM Code 78247 1 Mon. Site No. EFF-1	Permit Requirement					11[3] (Mo.Avg.)	11[3] (Day.Max.)	ug/L		Quarterly	24-hr TPC
Chromium, Hexavalent Total Recoverable (Intake)	Sample Measurement										
PARM Code 78247 Q Mon. Site No. INT-1	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ug/L		Quarterly	24-hr TPC
Copper, Total Recoverable (effluent)	Sample Measurement										
PARM Code 01119 1 Mon. Site No. EFF-1	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ug/L		Quarterly	24-hr TPC
Copper, Total Recoverable (calculated limit)	Sample Measurement										
PARM Code 01119 Q Mon. Site No. EFF-1	Permit Requirement					Report[4] (Mo.Avg.)	Report[4] (Day.Max.)	ug/L		Quarterly	Calculated
Copper, Total Recoverable (effluent minus calculated limit)	Sample Measurement										
PARM Code 01119 R Mon. Site No. EFF-1	Permit Requirement					Report[5] (Mo.Avg.)	Report (Day.Max.)	ug/L		Quarterly	Calculated
Copper, Total Recoverable (Intake)	Sample Measurement										
PARM Code 01119 S Mon. Site No. INT-1	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ug/L		Quarterly	24-hr TPC
Iron, Total Recoverable (effluent)	Sample Measurement										
PARM Code 00980 1 Mon. Site No. EFF-1	Permit Requirement					1.0[6] (Mo.Avg.)	1.0[5] (Day.Max.)	mg/L		Quarterly	24-hr TPC
Iron, Total Recoverable (Intake)	Sample Measurement										
PARM Code 00980 Q Mon. Site No. INT-1	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	mg/L		Quarterly	24-hr TPC
Lead, Total Recoverable (effluent)	Sample Measurement										
PARM Code 01114 1 Mon. Site No. EFF-1	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ug/L		Quarterly	24-hr TPC
Lead, Total Recoverable (calculated limit)	Sample Measurement										
PARM Code 01114 Q Mon. Site No. EFF-1	Permit Requirement					Report[7] (Mo.Avg.)	Report[6] (Day.Max.)	ug/L		Quarterly	Calculated

[3] See Permit Condition I.A.8 & I.A.9. If the concentration of the intake is greater than 11 ug/L, the intake concentration should be used as the effluent limit.

[4] See Permit Conditions I.A.7 & I.A.8. If the concentration of the intake is greater than the limit calculated in Condition I.A.7, the intake concentration should be used as the effluent limit.

[5] Copper has an Interim Limit see CO 10-2627-17-IW

[6] See Permit Condition I.A.8. If the concentration of the intake is greater than 1.0 mg/L, the intake concentration should be used as the effluent limit.

[7] See Permit Conditions I.A.7 & I.A.8. If the concentration of the intake is greater than the limit calculated in Condition I.A.7, the intake concentration should be used as the effluent limit.

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DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: Crist Electric Generating Plant

MONITORING GROUP NUMBER: D-010

PERMIT NUMBER: FL0002275-013-IW1S

MONITORING PERIOD From: ____________ To: ____________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No Ex.	Frequency of Analysis	Sample Type
Lead, Total Recoverable (effluent minus calculated limit)	Sample Measurement										
PARM Code 01114 R Mon. Site No. EFF-1	Permit Requirement					0.0 (Mo.Avg.)	0.0 (Day.Max.)	ug/L		Quarterly	Calculated
Lead, Total Recoverable (Intake)	Sample Measurement										
PARM Code 01114 S Mon. Site No. INT-1	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ug/L		Quarterly	24-hr TPC
Mercury, Total Recoverable (effluent)	Sample Measurement										
PARM Code 71901 1 Mon. Site No. EFF-1	Permit Requirement					0.012[8] (Mo.Avg.)	0.012[7] (Day.Max.)	ug/L		Quarterly	Grab
Mercury, Total Recoverable (Intake)	Sample Measurement										
PARM Code 71901 Q Mon. Site No. INT-1	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (effluent)	Sample Measurement										
PARM Code 01094 1 Mon. Site No. EFF-1	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ug/L		Quarterly	24-hr TPC
Zinc, Total Recoverable (calculated limit)	Sample Measurement										
PARM Code 01094 Q Mon. Site No. EFF-1	Permit Requirement					Report[9] (Mo.Avg.)	Report[8] (Day.Max.)	ug/L		Quarterly	Calculated
Zinc, Total Recoverable (effluent minus calculated limit)	Sample Measurement										
PARM Code 01094 R Mon. Site No. EFF-1	Permit Requirement					0.0 (Mo.Avg.)	0.0 (Day.Max.)	ug/L		Quarterly	Calculated
Zinc, Total Recoverable (Intake)	Sample Measurement										
PARM Code 01094 S Mon. Site No. INT-1	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ug/L		Quarterly	24-hr TPC
Hardness, Total (as CaCO3)	Sample Measurement										
PARM Code 00900 1 Mon. Site No. EFF-1	Permit Requirement						Report (Max.)	mg/L		Quarterly	24-hr TPC
Alpha, Gross Particle Activity (effluent)	Sample Measurement										
PARM Code 80045 1 Mon. Site No. EFF-1	Permit Requirement					15.0[10] (Mo.Avg.)	15.0[9] (Day.Max.)	pCi/L		Quarterly	24-hr TPC
Alpha, Gross Particle Activity (Intake)	Sample Measurement										
PARM Code 80045 Q Mon. Site No. INT-1	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	pCi/L		Quarterly	24-hr TPC

[8] See Permit Condition I.A.8. If the concentration of the intake is greater than 0.012 ug/L, the intake concentration should be used as the effluent limit.

[9] See Permit Conditions I.A.7 & I.A.8. If the concentration of the intake is greater than the limit calculated in Condition I.A.7, the intake concentration should be used as the effluent limit.

[10] See Permit Condition I.A.8. If the concentration of the intake is greater than 15.0 pCi/L, the intake concentration should be used as the effluent limit.

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: Crist Electric Generating Plant

MONITORING GROUP NUMBER: D-010

PERMIT NUMBER: FL0002275-013-IW1S

MONITORING PERIOD From: ________________ To: ____________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Radium 226 + Radium 228, Total (effluent)	Sample Measurement										
PARM Code 11503 1 Mon. Site No. EFF-1	Permit Requirement					5.0[11] (Mo.Avg.)	5.0[11] (Day.Max.)	pCi/L		Quarterly	24-hr TPC
Radium 226 + Radium 228, Total (Intake)	Sample Measurement										
PARM Code 11503 Q Mon. Site No. INT-1	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	pCi/L		Quarterly	24-hr TPC

[11] See Permit Condition I.A.8. If the concentration of the intake is greater than 5.0 pCi/L, the intake concentration should be used as the effluent limit.

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DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME	Gulf Power Company	PERMIT NUMBER:	FL0002275-013-IW1S		
MAILING ADDRESS	One Energy Place Pensacola, Florida 32520				
		LIMIT:	Final	REPORT FREQUENCY:	Monthly
		CLASS SIZE:	MA	PROGRAM:	Industrial
FACILITY:	Crist Electric Generating Plant	MONITORING GROUP NUMBER:	D-010		
LOCATION:	Ten Mile Road Pensacola, FL	MONITORING GROUP DESCRIPTION:	Combined Main Plant Discharge (Formerly D-001)		
		RE-SUBMITTED DMR:	☐		
		NO DISCHARGE FROM SITE:	☐		
COUNTY:	Escambia	MONITORING PERIOD From:	________	To:	________
OFFICE:	Northwest District				

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Flow	Sample Measurement										
PARM Code 50050 1 Mon. Site No. FLW-1	Permit Requirement	Report (Day Avg.)	Report (Day Max.)	MGD						Daily; 24 hours	Calculated
Temperature (F), Water	Sample Measurement										
PARM Code 00011 1 Mon. Site No. EFF-1	Permit Requirement					94.0 (Day Avg.)		Deg F		Continuous	Calculated
pH	Sample Measurement										
PARM Code 00400 1 Mon. Site No. EFF-1	Permit Requirement				6.0 (Day Min.)		8.5 (Day Max.)	s.u.		Weekly	Grab
Oxidants, Total Residual	Sample Measurement										
PARM Code [illegible] 1 Mon. Site No. EFF-1	Permit Requirement					0.01 (Mo Avg.)	0.01 (Day Max.)	mg/L		Weekly	Grab

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here)

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME:	Gulf Power Company	PERMIT NUMBER:	FL0002275-013-IW1S				
MAILING ADDRESS:	One Energy Place Pensacola, Florida 32520	LIMIT:	Final	REPORT FREQUENCY:	Quarterly		
		CLASS SIZE:	MA	PROGRAM:	Industrial		
FACILITY:	Crist Electric Generating Plant	MONITORING GROUP NUMBER:	D-010				
LOCATION:	Ten Mile Road Pensacola, FL	MONITORING GROUP DESCRIPTION:	Combined Main Plant Discharge (Formerly D-001)				
		RE-SUBMITTED DMR:	☐				
		NO DISCHARGE FROM SITE:	☐				
COUNTY:	Escambia	MONITORING PERIOD	From: ______ To: ______				
OFFICE:	Northwest District						

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
TRO-Discharge Time	Sample Measurement										
PARM Code 04233 1 Mon. Site No. [illegible]	Permit Requirement					120 (Mo.Avg.)	120 (Day Max.)	min/day		Quarterly	Meter
Oil and Grease	Sample Measurement										
PARM Code 00556 1 Mon. Site No. EFF-1	Permit Requirement				N/A	5.0 (Mo.Avg.)	5.0 (Day Max.)	mg/L		Quarterly	Grab
Arsenic, Total Recoverable (effluent)	Sample Measurement										
PARM Code 00978 1 Mon. Site No. EFF-1	Permit Requirement					50.0[1] (Mo.Avg.)	50.0[1] (Day Max.)	ug/L		Quarterly	24-hr TPC
Arsenic, Total Recoverable (Intake)	Sample Measurement										
PARM Code 00978 Q Mon. Site No. INT-1	Permit Requirement					Report (Mo.Avg.)	Report (Day Max.)	ug/L		Quarterly	24-hr TPC
Cadmium, Total Recoverable (effluent)	Sample Measurement										
PARM Code 01113 1 Mon. Site No. EFF-1	Permit Requirement					Report (Mo.Avg.)	Report (Day Max.)	ug/L		Quarterly	24-hr TPC
Cadmium, Total Recoverable (calculated limit)	Sample Measurement										
PARM Code 01113 Q Mon. Site No. EFF-1	Permit Requirement					Report[2] (Mo.Avg.)	Report[2] (Day Max.)	ug/L		Quarterly	Calculated
Cadmium, Total Recoverable (effluent minus calculated limit)	Sample Measurement										
PARM Code 01113 R Mon. Site No. EFF-1	Permit Requirement					0.0 (Mo.Avg.)	0.0 (Day Max.)	ug/L		Quarterly	Calculated

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO.	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

[1] See Permit Condition I.A.8. If the concentration of the intake is greater than 50.0 ug/L, the intake concentration should be used as the effluent limit.

[2] See Permit Conditions I.A.7 & I.A.8. If the concentration of the intake is greater than the limit calculated in Condition I.A.7, the intake concentration should be used as the effluent limit.

FACILITY: Crist Electric Generating Plant

MONITORING GROUP NUMBER: D-010

PERMIT NUMBER: FL0002275-013-IW1S

MONITORING PERIOD From: ____________ To: ____________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No Ex	Frequency of Analysis	Sample Type
Cadmium, Total Recoverable (Intake)	Sample Measurement										
PARM Code 01113 S Mon. Site No. INT-1	Permit Requirement					Report (Mo.Avg.)	Report (Day Max.)	ug/L		Quarterly	24-hr TPC
Chromium, Hexavalent Total Recoverable (Effluent)	Sample Measurement										
PARM Code 78247 I Mon. Site No. EFF-1	Permit Requirement					11[3] (Mo.Avg.)	11[3] (Day Max.)	ug/L		Quarterly	24-hr TPC
Chromium, Hexavalent Total Recoverable (Intake)	Sample Measurement										
PARM Code [illegible] Q [illegible]	Permit Requirement					Report (Mo.Avg.)	Report (Day Max.)	ug/L		Quarterly	24-hr TPC
Copper, Total Recoverable (effluent)	Sample Measurement										
PARM Code 01119 I [illegible]	Permit Requirement					Report (Mo.Avg.)	Report (Day Max.)	ug/L		Quarterly	24-hr TPC
Copper, Total Recoverable (calculated limit)	Sample Measurement										
PARM Code 01119 Q Mon. Site No. EFF-1	Permit Requirement					Report[4] (Mo.Avg.)	Report[4] (Day Max.)	ug/L		Quarterly	Calculated
Copper, Total Recoverable (effluent minus calculated limit)	Sample Measurement										
PARM Code 01119 R Mon. Site No. EFF-1	Permit Requirement					0.0 (Mo.Avg.)	0.0 (Day Max.)	ug/L		Quarterly	Calculated
Copper, Total Recoverable (Intake)	Sample Measurement										
PARM Code 01119 S Mon. Site No. INT-1	Permit Requirement					Report (Mo.Avg.)	Report (Day Max.)	ug/L		Quarterly	24-hr TPC
Iron, Total Recoverable (effluent)	Sample Measurement										
PARM Code [illegible] I Mon. Site No. EFF-1	Permit Requirement					1.0[5] (Mo.Avg.)	1.0[5] (Day Max.)	[illegible]		Quarterly	24-hr TPC
Iron, Total Recoverable (Intake)	Sample Measurement										
PARM Code 00980 Q Mon. Site No. INT-1	Permit Requirement					Report (Mo.Avg.)	Report (Day Max.)	mg/L		Quarterly	24-hr TPC
Lead, Total Recoverable (effluent)	Sample Measurement										
PARM Code 01114 I Mon. Site No. EFF-1	Permit Requirement					Report (Mo.Avg.)	Report (Day Max.)	ug/L		Quarterly	24-hr TPC
Lead, Total Recoverable (calculated limit)	Sample Measurement										
PARM Code 01114 Q Mon. Site No. EFF-1	Permit Requirement					Report[6] (Mo.Avg.)	Report[6] (Day Max.)	ug/L		Quarterly	Calculated

N/A

[3] See Permit Condition I.A.8 & I.A.9. If the concentration of the intake is greater than 11 ug/L, the intake concentration should be used as the effluent limit.

[4] See Permit Conditions I.A.7 & I.A.8. If the concentration of the intake is greater than the limit calculated in Condition I.A.7, the intake concentration should be used as the effluent limit.

[5] See Permit Condition I.A.8. If the concentration of the intake is greater than 1.0 mg/L, the intake concentration should be used as the effluent limit.

[6] See Permit Conditions I.A.7 & I.A.8. If the concentration of the intake is greater than the limit calculated in Condition I.A.7, the intake concentration should be used as the effluent limit.

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: Crist Electric Generating Plant

MONITORING GROUP NUMBER: D-010

PERMIT NUMBER: FL0002275-013-IW1S

MONITORING PERIOD From: ______________ To: ______________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Lead, Total Recoverable (effluent minus calculated limit)	Sample Measurement										
PARM Code 01114 R Mon. Site No. EFF-1	Permit Requirement					0.0 (Mo.Avg.)	0.0 (Day Max.)	ug/L		Quarterly	Calculated
Lead, Total Recoverable (Intake)	Sample Measurement										
PARM Code 01114 S Mon. Site No. INT-1	Permit Requirement					Report (Mo.Avg.)	Report (Day Max.)	ug/L		Quarterly	24-hr TPC
Mercury, Total Recoverable (effluent)	Sample Measurement										
PARM Code 71901 1 Mon. Site No. EFF-1	Permit Requirement					0.012[7] (Mo.Avg.)	0.012[7] (Day Max.)	ug/L		Quarterly	Grab
Mercury, Total Recoverable (Intake)	Sample Measurement										
PARM Code 71901 Q Mon. Site No. INT-1	Permit Requirement					Report (Mo.Avg.)	Report (Day Max.)	ug/L		Quarterly	Grab
Zinc, Total Recoverable (effluent)	Sample Measurement										
PARM Code 01094 1 Mon. Site No. EFF-1	Permit Requirement					Report (Mo.Avg.)	Report (Day Max.)	ug/L		Quarterly	24-hr TPC
Zinc, Total Recoverable (calculated limit)	Sample Measurement			NA							
PARM Code 01094 Q Mon. Site No. EFF-1	Permit Requirement					Report[8] (Mo.Avg.)	Report[8] (Day Max.)	ug/L		Quarterly	Calculated
Zinc, Total Recoverable (effluent minus calculated limit)	Sample Measurement										
PARM Code 01094 R Mon. Site No. EFF-1	Permit Requirement					0.0 (Mo.Avg.)	0.0 (Day Max.)	ug/L		Quarterly	Calculated
Zinc, Total Recoverable (Intake)	Sample Measurement										
PARM Code 01094 S Mon. Site No. INT-1	Permit Requirement					Report (Mo.Avg.)	Report (Day Max.)	ug/L		Quarterly	24-hr TPC
Hardness, Total (as CaCO3)	Sample Measurement										
PARM Code 00900 1 Mon. Site No. EFF-1	Permit Requirement						Report (Max.)	mg/L		Quarterly	24-hr TPC
Alpha, Gross Particle Activity (effluent)	Sample Measurement										
PARM Code 80045 1 Mon. Site No. EFF-1	Permit Requirement					15.0[9] (Mo.Avg.)	15.0[9] (Day Max.)	pCi/L		Quarterly	24-hr TPC
Alpha, Gross Particle Activity (Intake)	Sample Measurement										
PARM Code 80045 Q Mon. Site No. INT-1	Permit Requirement					Report (Mo.Avg.)	Report (Day Max.)	pCi/L		Quarterly	24-hr TPC

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[7] See Permit Condition I.A.8. If the concentration of the intake is greater than 0.012 ug/L, the intake concentration should be used as the effluent limit.

[8] See Permit Conditions I.A.7 & I.A.8. If the concentration of the intake is greater than the limit calculated in Condition I.A.7, the intake concentration should be used as the effluent limit.

[9] See Permit Condition I.A.8. If the concentration of the intake is greater than 15.0 pCi/L, the intake concentration should be used as the effluent limit.

Docket No. 110007-EI
Plant Crist NPDES Permit
Exhibit JOV-1, Page 45 of 63

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: Crist Electric Generating Plant

MONITORING GROUP NUMBER: D-010

PERMIT NUMBER: FL0002275-013-IW1S

MONITORING PERIOD From: ____________ To: ____________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No Ex.	Frequency of Analysis	Sample Type
Radium 226 + Radium 228, Total (effluent)	Sample Measurement										
PARM Code 11503 1 Mon. Site No. EFF-1	Permit Requirement					5.0[10] (Mo.Avg.)	5.0[10] (Day Max.)	pCi/L		Quarterly	24-hr TPC
Radium 226 + Radium 228, Total (Intake)	Sample Measurement										
PARM Code 11503 Q Mon. Site No. INT-1	Permit Requirement					Report (Mo.Avg.)	Report (Day Max.)	pCi/L		Quarterly	24-hr TPC

N/A

[10] See Permit Condition I.A.8. If the concentration of the intake is greater than 5.0 pCi/L, the intake concentration should be used as the effluent limit.

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME	Gulf Power Company	PERMIT NUMBER:	FL0002275-013-IW1S		
MAILING ADDRESS:	One Energy Place Pensacola, Florida 32520				
		LIMIT:	Final	REPORT FREQUENCY:	Annually
		CLASS SIZE:	MA	PROGRAM:	Industrial
FACILITY	Crist Electric Generating Plant	MONITORING GROUP NUMBER:	D-010		
LOCATION.	Ten Mile Road Pensacola, FL	MONITORING GROUP DESCRIPTION:	Combined Main Plant Discharge (Formerly D-001)		
		RE-SUBMITTED DMR:	☐		
		NO DISCHARGE FROM SITE:	☐		
COUNTY:	Escambia	MONITORING PERIOD From:	________	To:	________
OFFICE:	Northwest District				

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nickel, Total Recoverable (effluent)	Sample Measurement										
PARM Code 01074 1 Mon. Site No. EFF-1	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ug/L		Annually	24-hr TPC
Nickel. Total Recoverable (calculated limit)	Sample Measurement										
PARM Code 01074 Q Mon. Site No EFF-1	Permit Requirement					Report[11] (Mo.Avg.)	Report[11] (Day.Max.)	ug/L		Annually	Calculated
Nickel. Total Recoverable (effluent minus calculated limit)	Sample Measurement										
PARM Code 01074 R Mon. Site No. EFF-1	Permit Requirement					0.0 (Mo.Avg.)	0.0 (Max.)	ug/L		Annually	Calculated
Nickel. Total Recoverable (Intake)	Sample Measurement										
PARM Code 01074 S Mon. Site No. INT-1	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ug/L		Annually	24-hr TPC
Selenium, Total Recoverable (Effluent)	Sample Measurement										
PARM Code 00981 1 Mon. Site No. EFF-1	Permit Requirement					5.0[12] (Mo.Avg.)	5.0[12] (Day.Max.)	ug/L		Annually	24-hr TPC
Selenium, Total Recoverable (Intake)	Sample Measurement										
PARM Code 00981 Q Mon. Site No. INT-1	Permit Requirement					Report (Mo.Avg.)	Report (Day.Max.)	ug/L		Annually	24-hr TPC

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

[11] See Permit Conditions I.A.7 & I.A.8. If the concentration of the intake is greater than the limit calculated in Condition I.A.7, the intake concentration should be used as the effluent limit.

[12] See Permit Condition I.A.8 If the concentration of the intake is greater than 5.0 ug/L, the intake concentration should be used as the effluent limit.

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME:	Gulf Power Company	PERMIT NUMBER:	FL0002275-013-IW1S		
MAILING ADDRESS:	One Energy Place Pensacola, Florida 32520	LIMIT:	Final	REPORT FREQUENCY:	Toxicity
		CLASS SIZE:	MA	PROGRAM:	Industrial
FACILITY:	Crist Electric Generating Plant	MONITORING GROUP NUMBER:	D-010		
LOCATION:	Ten Mile Road Pensacola, FL	MONITORING GROUP DESCRIPTION:	Combined Main Plant Discharge (Formerly D-001)		
		RE-SUBMITTED DMR: ☐			
		NO DISCHARGE FROM SITE: ☐			
		MONITORING NOT REQUIRED: ☐			
COUNTY:	Escambia	MONITORING PERIOD From:	______	To:	______
OFFICE:	Northwest District				

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
7-DAY CHRONIC STATRE Ceriodaphnia dubia(Routine)	Sample Measurement										
PARM Code TRP3B P Mon. Site No. EFF-1	Permit Requirement				100 (Min.)			percent		Quarterly	24-hr TPC
7-DAY CHRONIC STATRE Ceriodaphnia dubia(Additional)	Sample Measurement										
PARM Code TRP3B Q Mon. Site No. EFF-1	Permit Requirement				100 (Min.)			percent		As needed	As required by the permit
7-DAY CHRONIC STATRE Ceriodaphnia dubia(Additional)	Sample Measurement										
PARM Code TRP3B R Mon. Site No. EFF-1	Permit Requirement				100 (Min.)			percent		As needed	As required by the permit
7-DAY CHRONIC STATRE Pimephales promelas(Routine)	Sample Measurement										
PARM Code TRP6C P Mon. Site No. EFF-1	Permit Requirement				100 (Min.)			percent		Quarterly	24-hr TPC
7-DAY CHRONIC STATRE Pimephales promelas(Additional)	Sample Measurement										
PARM Code TRP6C Q Mon. Site No. EFF-1	Permit Requirement				100 (Min.)			percent		As needed	As required by the permit
7-DAY CHRONIC STATRE Pimephales promelas(Additional)	Sample Measurement										
PARM Code TRP6C R Mon. Site No. EFF-1	Permit Requirement				100 (Min.)			percent		As needed	As required by the permit

*ENTER "MNR" IN THE RESULTS COLUMN FOR EACH TEST THAT IS NOT REQUIRED.

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO.	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: Crist Electric Generating Plant

MONITORING GROUP NUMBER: D-010

PERMIT NUMBER: FL0002275-013-IW1S

MONITORING PERIOD From: ____________ To: ____________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
7-DAY CHRONIC STATRE Mysidopsis bahia (Routine)	Sample Measurement										
PARM Code TRP3E P Mon. Site No. EFF-1	Permit Requirement				100 (Min.)			percent		Semi-Annually; twice per year	24-hr TPC
7-DAY CHRONIC STATRE Mysidopsis bahia (Additional)	Sample Measurement										
PARM Code TRP3E Q Mon. Site No. EFF-1	Permit Requirement				100 (Min.)			percent		As needed	As required by the permit
7-DAY CHRONIC STATRE Mysidopsis bahia (Additional)	Sample Measurement										
PARM Code TRP3E R Mon. Site No. EFF-1	Permit Requirement				100 (Min.)			percent		As needed	As required by the permit
7-DAY CHRONIC STATRE Menidia beryllina (Routine)	Sample Measurement										
PARM Code TRP6B P Mon. Site No. EFF-1	Permit Requirement				100 (Min.)			percent		Semi-Annually; twice per year	24-hr TPC
7-DAY CHRONIC STATRE Menidia beryllina (Additional)	Sample Measurement										
PARM Code TRP6B Q Mon. Site No. EFF-1	Permit Requirement				100 (Min.)			percent		As needed	As required by the permit
7-DAY CHRONIC STATRE Menidia beryllina (Additional)	Sample Measurement										
PARM Code TRP6B R Mon. Site No. EFF-1	Permit Requirement				100 (Min.)			percent		As needed	As required by the permit

*ENTER "MNR" IN THE RESULTS COLUMN FOR EACH TEST THAT IS NOT REQUIRED.

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

Docket No. 110007-EI
Plant Crist NPDES Permit
Exhibit JOV-1, Page 49 of 63

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME:	Gulf Power Company	PERMIT NUMBER:	FL0002275-013-IW1S		
MAILING ADDRESS:	One Energy Place Pensacola, Florida 32520				
		LIMIT:	Final	REPORT FREQUENCY:	Monthly
		CLASS SIZE:	MA	PROGRAM:	Industrial
FACILITY:	Crist Electric Generating Plant	MONITORING GROUP NUMBER:	I-1C0		
LOCATION:	Ten Mile Road Pensacola, FL	MONITORING GROUP DESCRIPTION:	Ash Pond Discharge to the Discharge Canal		
		RE-SUBMITTED DMR: ☐			
		NO DISCHARGE FROM SITE: ☐			
COUNTY:	Escambia	MONITORING PERIOD From:	________________	To:	________________
OFFICE:	Northwest District				

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Flow	Sample Measurement										
PARM Code 50050 1 Mon. Site No. FLW-3	Permit Requirement	Report (Mo.Avg.)	Report (Daily Max.)	MGD						Daily, when discharging	Flow Totalizer
Oil and Grease	Sample Measurement										
PARM Code 00556 1 Mon. Site No. EFF-2	Permit Requirement				7.0 (Mo.Avg.)	10.0 (Day Avg.)		mg/L		Biweekly; every 2 weeks	Grab
Solids, Total Suspended	Sample Measurement										
PARM Code 00530 1 Mon. Site No. EFF-2	Permit Requirement				30.0 (Mo.Avg.)	65.0 (Day Avg.)		mg/L		Weekly, when discharging	24-hr TPC
Hydrazine	Sample Measurement										
PARM Code 81313 1 Mon. Site No. EFF-2	Permit Requirement						380 (Inst.Max.)	mg/L		Weekly, when discharging [13]	Multiple Grab
pH	Sample Measurement										
PARM Code 00400 1 Mon. Site No. EFF-2	Permit Requirement				6.0 (Day Min.)		9.0 (Day Max.)	s.u.		Weekly, when discharging	Grab

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO.	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

[13] The monitoring frequency for hydrazine shall be three times per cold dump discharge event when the amount of residual hydrazine in the boiler water discharged into the ash pond during a two day period exceeds the threshold level of 43.2 kg. Monitoring for hydrazine is not required during a cold dump discharge event provided the total boiler water residual hydrazine amount being discharged is below 43.2 kg. The total amount of hydrazine going to the ash pond will be calculated by multiplying the capacity of each boiler being dumped within a two day period by the measured hydrazine residual concentration in that boiler.

A discharge event is defined as a cold dump of a single boiler following cold stand-by status which required hydrazine to be added to the boiler water to achieve concentrations higher than normal for protection of metal surfaces.

A two day period begins at the start of a boiler discharge to the pond and includes the subsequent 48 hours. Grab samples shall be taken at 6, 12, and 24 hours from the time approximately 50 percent of the discharge is complete.

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DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME: Gulf Power Company
MAILING ADDRESS: One Energy Place
Pensacola, Florida 32520

FACILITY: Crist Electric Generating Plant
LOCATION: Ten Mile Road
Pensacola, FL

COUNTY: Escambia
OFFICE: Northwest District

PERMIT NUMBER: FL0002275-013-IW1S

LIMIT: Final
CLASS SIZE: MA
MONITORING GROUP NUMBER: I-150
MONITORING GROUP DESCRIPTION: Metal Cleaning Wastes to the Ash Pond
RE-SUBMITTED DMR: ☐
NO DISCHARGE FROM SITE: ☐
MONITORING PERIOD From: ____________ To: ____________

REPORT FREQUENCY: Monthly
PROGRAM: Industrial

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Flow	Sample Measurement										
PARM Code 50050 1 Mon. Site No. [illegible]	Permit Requirement	Report (Mo.Avg.)	Report (Day Max.)	MGD						Per discharge	Calculated
Copper, Total Recoverable	Sample Measurement										
PARM Code 01119 1 Mon. Site No. EFF-3	Permit Requirement					1.0 (Mo.Avg.)	1.0 (Day Max.)	mg/L		Per discharge	Composite[14]
Iron, Total Recoverable	Sample Measurement										
PARM Code 00980 1 Mon. Site No. EFF-3	Permit Requirement					1.0 (Mo.Avg.)	1.0 (Day Max.)	mg/L		Per discharge	Composite[23]
Solids, Total Suspended	Sample Measurement										
PARM Code 00530 1 Mon. Site No. EFF-3	Permit Requirement					30.0 (Mo.Avg.)	100.0 (Day Max.)	mg/L		Per discharge	Composite[23]
Oil and Grease	Sample Measurement										
PARM Code 00556 1 Mon. Site No. EFF-3	Permit Requirement					15.0 (Mo.Avg.)	20.0 (Day Max.)	mg/L		Per discharge	Grab

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO.	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

[14] One aliquot collected immediately after the start of discharge to the ash pond, one aliquot immediately prior to termination of the discharge, and six aliquots collected at approximately equal times in between.

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME:	Gulf Power Company	PERMIT NUMBER:	FL0002275-013-IW1S		
MAILING ADDRESS:	One Energy Place				
	Pensacola, Florida 32520	LIMIT:	Final	REPORT FREQUENCY:	Monthly
		CLASS SIZE:	MA	PROGRAM:	Industrial
FACILITY:	Crist Electric Generating Plant	MONITORING GROUP NUMBER:	I-170		
LOCATION:	Ten Mile Road	MONITORING GROUP DESCRIPTION:	Units 6 and 7 Cooling Tower Blowdown to the Ash Pond When River Water is Used as Make-up Water for the Cooling Towers		
	Pensacola, FL	RE-SUBMITTED DMR: ☐			
		NO DISCHARGE FROM SITE: ☐			
COUNTY:	Escambia	MONITORING PERIOD From:	__________ To: __________		
OFFICE:	Northwest District				

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Flow	Sample Measurement										
PARM Code 50050 1 Mon. Site No. FLW-5	Permit Requirement	Report (Mo.Avg.)	Report (Dy.Max.)	MGD						Weekly, when discharging	Calculated
Total Residual Oxidants (Discharge Time)	Sample Measurement										
PARM Code 04223 1 Mon. Site No. EFF-1	Permit Requirement					120 (Mo.Avg.)	120 (Dy.Max.)	min/day		Daily, when discharging	Meter
Oxidants, Free Available	Sample Measurement										
PARM Code 34045 1 Mon. Site No. OUI-6	Permit Requirement					0.2[15] (Mo.Avg.)	0.5[15] (Dy.Max.)	mg/L		Per occurrence	Grab

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO.	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

[15] Limitations and monitoring requirements for Free Available Oxidants shall be applicable when an oxidant (e.g., chlorine or Nalco Actibrom 7342) is used in the cooling towers for Units 6 and 7 and the blowdown is discharged to the ash pond.

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME:	Gulf Power Company	PERMIT NUMBER:	FL0002275-013-IW1S		
MAILING ADDRESS:	One Energy Place Pensacola, Florida 32520				
		LIMIT:	Final	REPORT FREQUENCY:	Quarterly
		CLASS SIZE:	MA	PROGRAM:	Industrial
FACILITY:	Crist Electric Generating Plant	MONITORING GROUP NUMBER:	I-170		
LOCATION:	Ten Mile Road Pensacola, FL	MONITORING GROUP DESCRIPTION:	Units 6 and 7 Cooling Tower Blowdown to the Ash Pond When River Water is Used as Make-up Water for the Cooling Towers		
		RE-SUBMITTED DMR:	☐		
		NO DISCHARGE FROM SITE:	☐		
COUNTY:	Escambia	MONITORING PERIOD From:	________ To ________		
OFFICE:	Northwest District				

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Chromium, Total Recoverable	Sample Measurement										
PARM Code 01118 1 Mon. Site No. OUI-6	Permit Requirement					0.2 (Mo.Avg.)	0.2 (Day Max.)	mg/L		Quarterly, when discharging	Grab
Zinc, Total Recoverable	Sample Measurement										
PARM Code 01094 1 Mon. Site No. OUI-6	Permit Requirement					1.0 (Mo.Avg.)	1.0 (Day Max.)	mg/L		Quarterly, when discharging	Grab

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME MAILING ADDRESS	Gulf Power Company One Energy Place Pensacola, Florida 32520	PERMIT NUMBER:	FL0002275-013-IW1S		
		LIMIT CLASS SIZE MONITORING GROUP NUMBER: MONITORING GROUP DESCRIPTION:	Final MA I-180 ECUA Reclaimed Water and Units 6 and 7 Cooling Tower Blowdown when ECUA Reclaimed Water is Used as Makeup "Spent Reclaimed Water"	REPORT FREQUENCY: PROGRAM:	Monthly Industrial
FACILITY: LOCATION:	Crist Electric Generating Plant Ten Mile Road Pensacola, FL	RE-SUBMITTED DMR: ☐ NO DISCHARGE FROM SITE: ☐			
COUNTY: OFFICE:	Escambia Northwest District	MONITORING PERIOD From:	________ To: ________		

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Flow	Sample Measurement										
PARM Code 50050 Y Mon. Site No. FLW-5	Permit Requirement		20 (An.Avg.)	MGD						Continuous	Flow Totalizer
Flow	Sample Measurement										
PARM Code 50050 1 Mon. Site No. FLW-5	Permit Requirement		Report (Mo.Avg.)	MGD						Continuous	Flow Totalizer
Flow	Sample Measurement										
PARM Code 50050 Q Mon. Site No. FLW-6	Permit Requirement		855 (An.Max.)	MGD						Continuous	Flow Totalizer
Flow	Sample Measurement										
PARM Code 50050 R Mon. Site No. FLW-6	Permit Requirement	Report (Mo.Avg.)	Report (Day.Max.)	MGD						Continuous	Flow Totalizer
Flow	Sample Measurement										
PARM Code 50050 S Mon. Site No. FLW-7	Permit Requirement		855 (An.Max.)	MGD						Continuous	Flow Totalizer
Flow	Sample Measurement										
PARM Code 50050 T Mon. Site No. FLW-7	Permit Requirement	Report (Mo.Avg.)	Report (Day.Max.)	MGD						Continuous	Flow Totalizer
Duration of Discharge	Sample Measurement										
PARM Code 81381 1 Mon. Site No. FLW-5	Permit Requirement		Report (An.Total)	hr						Weekly, when discharging	Calculated

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: Crist Electric Generating Plant

MONITORING GROUP NUMBER: I-180

MONITORING PERIOD From: ____________ To: ____________

PERMIT NUMBER: FL0002275-013-IW1S

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No Ex.	Frequency of Analysis	Sample Type
Duration of Discharge	Sample Measurement										
PARM Code 81381 Q Mon. Site No. FLW-6	Permit Requirement	Report (Mo.Total)		Hr/month						Weekly, when discharging	Calculated
Duration of Discharge	Sample Measurement										
PARM Code 81381 R Mon. Site No. [illegible]	Permit Requirement		Report (An.Total)	hr						Weekly, when discharging	Calculated
Duration of Discharge	Sample Measurement										
PARM Code 81381 S Mon. Site No. FLW-7	Permit Requirement	Report (Mo.Total)		hr/month						Weekly, when discharging	Calculated
TRO-Discharge Time	Sample Measurement										
PARM Code 04223 P Mon. Site No. OUI-6	Permit Requirement					120 (Mo.Avg.)	120 (Day.Max.)	min/day		Weekly, when discharging	Calculated
TRO-Discharge Time	Sample Measurement										
PARM Code 04223 Q Mon. Site No. OUI-7	Permit Requirement					120 (Mo.Avg.)	120 (Day.Max.)	min/day		Weekly, when discharging	Calculated
Oxidants, Total Residual	Sample Measurement										
PARM Code 34044 P Mon. Site No. OUI-6	Permit Requirement					0.2[16] (Mo.Avg.)	0.5[16] (Day.Max.)	mg/L		Weekly, when discharging	Grab
Oxidants, Total Residual	Sample Measurement										
PARM Code 34044 Q Mon. Site No. OUI-7	Permit Requirement					0.2[16] (Mo.Avg.)	0.5[16] (Day.Max.)	mg/L		Weekly, when discharging	Grab
Nitrogen, Ammonia, Total (as N)	Sample Measurement										
PARM Code 00610 P Mon. Site No. OUI-5	Permit Requirement				Report (Mo.Avg.)	Report (Wk.Avg.)	Report (Day.Max.)	mg/L		Weekly, when discharging	Grab
Nitrogen, Ammonia, Total (as N)	Sample Measurement										
PARM Code 00610 Q Mon. Site No. OUI-6	Permit Requirement				Report (Mo.Avg.)	Report (Wk.Avg.)	Report (Day.Max.)	mg/L		Weekly, when discharging	Grab
Nitrogen, Ammonia, Total (as N)	Sample Measurement										
PARM Code 00610 R Mon. Site No. OUI-7	Permit Requirement				Report (Mo.Avg.)	Report (Wk.Avg.)	Report (Day.Max.)	mg/L		Weekly, when discharging	Grab
Nitrogen, Kjeldahl, Total (as N)	Sample Measurement										
PARM Code 00625 P Mon. Site No. OUI-5	Permit Requirement				Report (Mo.Avg.)	Report (Wk.Avg.)	Report (Day.Max.)	mg/L		Weekly, when discharging	Grab

[16] Limitations and monitoring requirements for Total Residual Oxidants and Free Available Oxidants shall be applicable when an oxidant (e.g., chlorine or Nalco Actibrom 7342) is used in the cooling towers for Units 6 and 7 and discharging the blowdown to surface waters of the state

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: Crist Electric Generating Plant

MONITORING GROUP NUMBER: I-180

MONITORING PERIOD From: ______________ To: ______________

PERMIT NUMBER: FL0002275-013-IW1S

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Nitrogen, Kjeldahl, Total (as N)	Sample Measurement										
PARM Code 00625 Q Mon. Site No. OUI-6	Permit Requirement				Report (Mo.Avg.)	Report (Wk.Avg.)	Report (Day.Max.)	mg/L		Weekly, when discharging	Grab
Nitrogen, Kjeldahl, Total (as N)	Sample Measurement										
PARM Code 00625 R Mon. Site No. OUI-7	Permit Requirement				Report (Mo.Avg.)	Report (Wk.Avg.)	Report (Day.Max.)	mg/L		Weekly, when discharging	Grab
Nitrite plus Nitrate, Total 1 det. (as N)	Sample Measurement										
PARM Code 00630 P Mon. Site No. OUI-5	Permit Requirement				Report (Mo.Avg.)	Report (Wk.Avg.)	Report (Day.Max.)	mg/L		Weekly, when discharging	Grab
Nitrite plus Nitrate, Total (as N)	Sample Measurement										
PARM Code 00630 Q Mon. Site No. OUI-6	Permit Requirement				Report (Mo.Avg.)	Report (Wk.Avg.)	Report (Day.Max.)	mg/L		Weekly, when discharging	Grab
Nitrite plus Nitrate, Total (as N)	Sample Measurement										
PARM Code 00630 R Mon. Site No. OUI-7	Permit Requirement				Report (Mo.Avg.)	Report (Wk.Avg.)	Report (Day.Max.)	mg/L		Weekly, when discharging	Grab
Nitrogen, Total	Sample Measurement										
PARM Code 00600 P Mon. Site No. OUI-5	Permit Requirement				3.75 (Mo.Avg.)	4.5 (Wk.Avg.)	6.0 (Day.Max.)	mg/L		Weekly, when discharging	Calculated
Nitrogen, Total	Sample Measurement										
PARM Code 00600 Q Mon. Site No. OUI-6	Permit Requirement				Report (Mo.Avg.)	Report (Wk.Avg.)		mg/L		Weekly, when discharging	Grab
Nitrogen, Total	Sample Measurement										
PARM Code 00600 R Mon. Site No. OUI-7	Permit Requirement				Report (Mo.Avg.)	Report (Wk.Avg.)		mg/L		Weekly, when discharging	Grab
Nitrogen, Total (Reclaimed Water Pipeline for Makeup)	Sample Measurement										
PARM Code 00600 S Mon. Site No. OUI-5	Permit Requirement		Report (Mo.Total)	lbs /month						Weekly, when discharging	Grab
Nitrogen, Total (Cooling Tower Conveyance Line)	Sample Measurement										
PARM Code 00600 T Mon. Site No. OUI-6	Permit Requirement		Report (Mo.Total)	lbs /month						Weekly, when discharging	Grab
Nitrogen, Total (Reclaimed Water Pipeline Prior to Discharge to Discharge Tunnel)	Sample Measurement										
PARM Code 00600 U Mon. Site No. OUI-7	Permit Requirement		Report (Mo.Total)	lbs /month						Weekly, when discharging	Grab

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY: Gulf Power Company - Crist Power Plant

MONITORING GROUP NUMBER: I-180

MONITORING PERIOD From: ______________ To: ______________

PERMIT NUMBER: FL0002275-013-IW1S

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No Ex.	Frequency of Analysis	Sample Type
Nitrogen, Total (Monthly Net Loading – Water from ECUA/Discharge Line to Overall Intake)	Sample Measurement										
PARM Code 00600 X Mon. Site No. [illegible]	Permit Requirement		Report[17] (Mo.Total)	lbs/month						Weekly, when discharging	Grab
Nitrogen, Total (Monthly Net Loading – Water from ECUA/Discharge Line to Discharge Canal)	Sample Measurement										
PARM Code 00600 Z Mon. Site No. OUI-5, OUI-7	Permit Requirement		Report[17] (Mo.Total)	lbs/month						Weekly, when discharging	Grab
Nitrogen, Total (Annual Net Loading – Water from ECUA/Discharge Line to Overall Intake)	Sample Measurement										
PARM Code 00600 V Mon. Site No. OUI-5, OUI-6	Permit Requirement		Report[18] (An.Total)	lbs/year						Weekly, when discharging	Calculated
Nitrogen, Total (Annual Net Loading – Water from ECUA/Discharge Line to Discharge Canal)	Sample Measurement										
PARM Code 00600 W Mon. Site No. OUI-5, OUI-7	Permit Requirement		Report[17] (An.Total)	lbs/year						Weekly, when discharging	Calculated
Phosphorus, Total (as P)	Sample Measurement										
PARM Code 00665 P Mon. Site No. [illegible]	Permit Requirement				0.4 (Mo.Avg.)	0.6 (Wk.Avg.)	0.8 (Day Max.)	mg/L		Weekly, when discharging	Grab
Phosphorus, Total (as P)	Sample Measurement										
PARM Code 00665 Q Mon. Site No. OUI-6	Permit Requirement					Report (Wk.Avg.)		mg/L		Weekly, when discharging	Grab
Phosphorus, Total (as P)	Sample Measurement										
PARM Code 00665 R Mon. Site No. OUI-7	Permit Requirement					Report (Wk.Avg.)		mg/L		Weekly, when discharging	Grab
Phosphorus, Total (as P) (Reclaimed Water Pipeline for Makeup)	Sample Measurement										
PARM Code 00665 S Mon. Site No. OUI-5	Permit Requirement		Report (Mo.Total)	lbs/month						Weekly, when discharging	Grab
Phosphorus, Total (as P) (Cooling Tower Conveyance Line)	Sample Measurement										
PARM Code 00665 T Mon. Site No. [illegible]	Permit Requirement		Report (Mo.Total)	lbs/month						Weekly, when discharging	Grab
Phosphorus, Total (as P) (Reclaimed Water Pipeline Prior to Discharge to Discharge Tunnel)	Sample Measurement										
PARM Code 00665 X Mon. Site No. OUI-7	Permit Requirement		Report (Mo.Total)	lbs/month						Weekly, when discharging	Grab

[17] The net Total Nitrogen (TN) loading is defined as the pounds of TN discharged at OUI-6 or OUI-7 minus the pounds of TN in the makeup water for Units 6 and 7 cooling towers at OUI-5, over a corresponding time period. The permittee shall report the monthly net TN loading, which equals the pounds of TN discharged during a month minus the pounds of TN entering Units 6 and 7 cooling towers during the same month

[18] The annual net loading (in pounds per year) on any given month is equal to the monthly net loading for that month plus the previous eleven monthly loadings and is considered a rolling annual maximum value.

DISCHARGE MONITORING REPORT - PART A (Continued)

FACILITY Gulf Power Company - Crist Power Plant

MONITORING GROUP NUMBER: I-180

PERMIT NUMBER: FL0002275-013-IW1S

MONITORING PERIOD From: ________________ To: ________________

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Phosphorus, Total (as P) (Monthly Net Loading – Water from ECUA/Discharge Line to Overall Intake)	Sample Measurement										
PARM Code 00665 U Mon. Site No. OUI-5, OUI-6	Permit Requirement		Report[19] (Mo.Total)	lbs/ month						Weekly, when discharging	Grab
Phosphorus, Total (as P) (Monthly Net Loading – Water from ECUA/Discharge Line to Discharge Canal)	Sample Measurement										
PARM Code 00665 Z Mon. Site No. OUI-5, OUI-7	Permit Requirement		Report[20] (Mo.Total)	lbs/ month						Weekly, when discharging	Grab
Phosphorus, Total (as P) (Annual Net Loading – Water from ECUA/Discharge Line to Overall Intake)	Sample Measurement										
PARM Code 00665 V Mon. Site No. OUI-5, OUI-6	Permit Requirement		Report[21] (An.Total)	lbs/ year						Weekly, when discharging	Calculated
Phosphorus, Total (as P) (Annual Net Loading – Water from ECUA/Discharge Line to Overall Intake)	Sample Measurement										
PARM Code 00665 W Mon. Site No. OUI-5, OUI-7	Permit Requirement		Report[21] (An.Total)	lbs/ year						Weekly, when discharging	Calculated

[19] The net Total Phosphorus (TP) loading is defined as the pounds of TP discharged at OUI-6 or OUI-7 minus the pounds of TP in the makeup water for Units 6 and 7 cooling towers at OUI-5, over a corresponding time period. The permittee shall report the monthly net TP loading, which equals the pounds of TP discharged during a month minus the pounds of TP entering Units 6 and 7 cooling towers during the same month.

[20] The net Total Phosphorus (TP) loading is defined as the pounds of TP discharged at OUI-6 or OUI-7 minus the pounds of TP in the makeup water for Units 6 and 7 cooling towers at OUI-5, over a corresponding time period. The permittee shall report the monthly net TP loading, which equals the pounds of TP discharged during a month minus the pounds of TP entering Units 6 and 7 cooling towers during the same month.

[21] The annual net loading (in pounds per year) on any given month is equal to the monthly net loading for that month plus the previous eleven monthly loadings and is considered a rolling annual maximum value.

DEPARTMENT OF ENVIRONMENTAL PROTECTION DISCHARGE MONITORING REPORT - PART A

When Completed mail this report to: Department of Environmental Protection, Wastewater Compliance Evaluation Section, MS 3551, 2600 Blair Stone Road, Tallahassee, FL 32399-2400

PERMITTEE NAME:	Gulf Power	PERMIT NUMBER:	FL0002275-013-IW1S		
MAILING ADDRESS:	1 Energy Pl Pensacola, Florida 32520-	LIMIT:	Final	REPORT FREQUENCY:	Quarterly
		CLASS SIZE:	MA	PROGRAM:	Industrial
FACILITY:	Gulf Power Company - Crist Power Plant	MONITORING GROUP NUMBER:	I-180		
LOCATION:	Ten Mile Road Pensacola, FL	MONITORING GROUP DESCRIPTION:	ECUA reclaimed water and Units 6 and 7 cooling tower blowdown when ECUA reclaimed water is used as makeup "spent reclaimed water"		
		RE-SUBMITTED DMR:	☐		
		NO DISCHARGE FROM SITE:	☐		
COUNTY:	Escambia	MONITORING PERIOD From:	__________ To: __________		
OFFICE:	Northwest District				

Parameter		Quantity or Loading		Units	Quality or Concentration			Units	No. Ex.	Frequency of Analysis	Sample Type
Chromium, Total Recoverable	Sample Measurement										
PARM Code 01118 P Mon. Site No. OUI-6	Permit Requirement					0.2[32] (Mo.Avg.)	0.2[32] (Day Max.)	mg/L		Quarterly, when discharging	Grab
Chromium, Total Recoverable	Sample Measurement										
PARM Code 01118 Q Mon. Site No. [illegible]	Permit Requirement					0.2[32] (Mo.Avg.)	0.2[32] (Day Max.)	mg/L		Quarterly, when discharging	Grab
Zinc, Total Recoverable	Sample Measurement										
PARM Code 01094 P Mon. Site No. OUI-6	Permit Requirement					1.0[32] (Mo.Avg.)	1.0[32] (Day Max.)	mg/L		Quarterly, when discharging	Grab
Zinc, Total Recoverable	Sample Measurement										
PARM Code 01094 Q Mon. Site No. OUI-7	Permit Requirement					1.0[32] (Mo.Avg.)	1.0[32] (Day Max.)	mg/L		Quarterly, when discharging	Grab

I certify under penalty of law that this document and all attachments were prepared under my direction or supervision in accordance with a system designed to assure that qualified personnel properly gather and evaluate the information submitted. Based on my inquiry of the person or persons who manage the system, or those persons directly responsible for gathering the information, the information submitted is, to the best of my knowledge and belief, true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment for knowing violations.

NAME/TITLE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	SIGNATURE OF PRINCIPAL EXECUTIVE OFFICER OR AUTHORIZED AGENT	TELEPHONE NO	DATE (mm/dd/yyyy)

COMMENT AND EXPLANATION OF ANY VIOLATIONS (Reference all attachments here):

[32] Limitations and monitoring requirements for Total Recoverable Chromium and Total Recoverable Zinc shall be applicable when discharging the cooling tower blowdown to surface waters of the state

INSTRUCTIONS FOR COMPLETING THE WASTEWATER DISCHARGE MONITORING REPORT

Read these instructions before completing the DMR. Hard copies and/or electronic copies of the required parts of the DMR were provided with the permit. All required information shall be completed in full and typed or printed in ink. A signed, original DMR shall be mailed to the address printed on the DMR by the 28th of the month following the monitoring period. The DMR shall not be submitted before the end of the monitoring period.

The DMR consists of three parts--A, B, and D--all of which may or may not be applicable to every facility. Facilities may have one or more Part A's for reporting effluent or reclaimed water data. All domestic wastewater facilities will have a Part B for reporting daily sample results. Part D is used for reporting ground water monitoring well data.

When results are not available, the following codes should be used on parts A and D of the DMR and an explanation provided where appropriate. Note: Codes used on Part B for raw data are different.

CODE	DESCRIPTION/INSTRUCTIONS
ANC	Analysis not conducted.
DRY	Dry Well
FLD	Flood disaster.
IFS	Insufficient flow for sampling.
LS	Lost sample
MNR	Monitoring not required this period.

CODE	DESCRIPTION/INSTRUCTIONS
NOD	No discharge from/to site.
OPS	Operations were shutdown so no sample could be taken.
OTH	Other. Please enter an explanation of why monitoring data were not available.
SEF	Sampling equipment failure.

When reporting analytical results that fall below a laboratory's reported method detection limits or practical quantification limits, the following instructions should be used:

1. Results greater than or equal to the PQL shall be reported as the measured quantity.
2. Results less than the PQL and greater than or equal to the MDL shall be reported as the laboratory's MDL value. These values shall be deemed equal to the MDL when necessary to calculate an average for that parameter and when determining compliance with permit limits.
3. Results less than the MDL shall be reported by entering a less than sign ("<") followed by the laboratory's MDL value, e.g. < 0.001. A value of one-half the MDL or one-half the effluent limit, whichever is lower, shall be used for that sample when necessary to calculate an average for that parameter. Values less than the MDL are considered to demonstrate compliance with an effluent limitation.

PART A -DISCHARGE MONITORING REPORT (DMR)

Part A of the DMR is comprised of one or more sections, each having its own header information. Facility information is preprinted in the header as well as the monitoring group number, whether the limits and monitoring requirements are interim or final, and the required submittal frequency (e.g. monthly, annually, quarterly, etc.). Submit Part A based on the required reporting frequency in the header and the instructions shown in the permit. The following should be completed by the permittee or authorized representative:

Resubmitted DMR: Check this box if this DMR is being re-submitted because there was information missing from or information that needed correction on a previously submitted DMR. The information that is being revised should be clearly noted on the re-submitted DMR (e.g. highlight, circle, etc.)
No Discharge From Site: Check this box if no discharge occurs and, as a result, there are no data or codes to be entered for all of the parameters on the DMR for the entire monitoring group number; however, if the monitoring group includes other monitoring locations (e.g., influent sampling), the "NOD" code should be used to individually denote those parameters for which there was no discharge.
Monitoring Period: Enter the month, day, and year for the first and last day of the monitoring period (i.e. the month, the quarter, the year, etc.) during which the data on this report were collected and analyzed.
Sample Measurement: Before filling in sample measurements in the table, check to see that the data collected correspond to the limit indicated on the DMR (i.e. interim or final) and that the data correspond to the monitoring group number in the header. Enter the data or calculated results for each parameter on this row in the non-shaded area above the limit. Be sure the result being entered corresponds to the appropriate statistical base code (e.g. annual average, monthly average, single sample maximum, etc.) and units.
No. Ex.: Enter the number of sample measurements during the monitoring period that exceeded the permit limit for each parameter in the non-shaded area. If none, enter zero.
Frequency of Analysis: The shaded areas in this column contain the minimum number of times the measurement is required to be made according to the permit. Enter the actual number of times the measurement was made in the space above the shaded area.
Sample Type: The shaded areas in this column contain the type of sample (e.g. grab, composite, continuous) required by the permit. Enter the actual sample type that was taken in the space above the shaded area.
Signature: This report must be signed in accordance with Rule 62-620.305, F.A.C. Type or print the name and title of the signing official. Include the telephone number where the official may be reached in the event there are questions concerning this report. Enter the date when the report is signed.
Comment and Explanation of Any Violations: Use this area to explain any exceedances, any upset or by-pass events, or other items which require explanation. If more space is needed, reference all attachments in this area.

PART B - DAILY SAMPLE RESULTS

Monitoring Period: Enter the month, day, and year for the first and last day of the monitoring period (i.e. the month, the quarter, the year, etc.) during which the data on this report were collected and analyzed.
Daily Monitoring Results: Transfer all analytical data from your facility's laboratory or a contract laboratory's data sheets for all day(s) that samples were collected. Record the data in the units indicated. Table 1 in Chapter 62-160, F.A.C., contains a complete list of all the data qualifier codes that your laboratory may use when reporting analytical results. However, when transferring numerical results onto Part B of the DMR, only the following data qualifier codes should be used and an explanation provided where appropriate.

CODE	DESCRIPTION/INSTRUCTIONS
<	The compound was analyzed for but not detected.
A	Value reported is the mean (average) of two or more determinations.
J	Estimated value, value not accurate.
Q	Sample held beyond the actual holding time.
Y	Laboratory analysis was from an unpreserved or improperly preserved sample.

To calculate the monthly average, add each reported value to get a total. For flow, divide this total by the number of days in the month. For all other parameters, divide the total by the number of observations.
Plant Staffing: List the name, certificate number, and class of all state certified operators operating the facility during the monitoring period. Use additional sheets as necessary.

PART D - GROUND WATER MONITORING REPORT

Monitoring Period: Enter the month, day, and year for the first and last day of the monitoring period (i.e. the month, the quarter, the year, etc.) during which the data on this report were collected and analyzed.
Date Sample Obtained: Enter the date the sample was taken. Also, check whether or not the well was purged before sampling.
Time Sample Obtained: Enter the time the sample was taken.
Sample Measurement: Record the results of the analysis. If the result was below the minimum detection limit, indicate that.
Detection Limits: Record the detection limits of the analytical methods used.
Analysis Method: Indicate the analytical method used. Record the method number from Chapter 62-160 or Chapter 62-601, F.A.C., or from other sources.
Sampling Equipment Used: Indicate the procedure used to collect the sample (e.g. airlift, bucket/bailer, centrifugal pump, etc.)
Samples Filtered: Indicate whether the sample obtained was filtered by laboratory (L), filtered in field (F), or unfiltered (N).
Signature: This report must be signed in accordance with Rule 62-620.305, F.A.C. Type or print the name and title of the signing official. Include the telephone number where the official may be reached in the event there are questions concerning this report. Enter the date when the report is signed.
Comments and Explanation: Use this space to make any comments on or explanations of results that are unexpected. If more space is needed, reference all attachments in this area.

SPECIAL INSTRUCTIONS FOR LIMITED WET WEATHER DISCHARGES

Flow (Limited Wet Weather Discharge): Enter the measured average flow rate during the period of discharge or divide gallons discharged by duration of discharge (converted into days). Record in million gallons per day (MGD).
Flow (Upstream): Enter the average flow rate in the receiving stream upstream from the point of discharge for the period of discharge. The average flow rate can be calculated based on two measurements; one made at the start and one made at the end of the discharge period. Measurements are to be made at the upstream gauging station described in the permit.
Actual Stream Dilution Ratio: To calculate the Actual Stream Dilution Ratio, divide the average upstream flow rate by the average discharge flow rate. Enter the Actual Stream Dilution Ratio accurate to the nearest 0.1.
No. of Days the SDF > Stream Dilution Ratio: For each day of discharge, compare the minimum Stream Dilution Factor (SDF) from the permit to the calculated Stream Dilution Ratio. On Part B of the DMR, enter an asterisk (*) if the SDF is greater than the Stream Dilution Ratio on any day of discharge. On Part A of the DMR, add up the days with an "*" and record the total number of days the Stream Dilution Factor was greater than the Stream Dilution Ratio.
$CBOD_5$: Enter the average $CBOD_5$ of the reclaimed water discharged during the period shown in duration of discharge.
TKN: Enter the average TKN of the reclaimed water discharged during the period shown in duration of discharge.
Actual Rainfall: Enter the actual rainfall for each day on Part B. Enter the actual cumulative rainfall to date for this calendar year and the actual total monthly rainfall on Part A. The cumulative rainfall to date for this calendar year is the total amount of rain, in inches, that has been recorded since January 1 of the current year through the month for which this DMR contains data.
Rainfall During Average Rainfall Year: On Part A, enter the total monthly rainfall during the average rainfall year and the cumulative rainfall for the average rainfall year. The cumulative rainfall for the average rainfall year is the amount of rain, in inches, which fell during the average rainfall year from January through the month for which this DMR contains data.
No. of Days LWWD Activated During Calendar Year: Enter the cumulative number of days that the limited wet weather discharge was activated since January 1 of the current year.
Reason for Discharge: Attach to the DMR a brief explanation of the factors contributing to the need to activate the limited wet weather discharge.

Department of Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

DEP Form #: 62-701.900(31)
Form Title: Water Quality Monitoring Certification
Effective Date: January 6, 2010
Incorporated in Rule 62-701.510(9)

WATER QUALITY MONITORING CERTIFICATION

PART I GENERAL INFORMATION

(1) Facility Name ______________________________

Address ______________________________

City ______________________ Zip ____________ County ____________

Telephone Number (____) ______________________________

(2) WACS Facility ID ______________________________

(3) DEP Permit Number ______________________________

(4) Authorized Representative's Name ______________________ Title ____________

Address ______________________________

City ______________________ Zip ____________ County ____________

Telephone Number (____) ______________________________

Email address (if available) ______________________________

CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submission of false information including the possibility of fine and imprisonment.

______________ (Date) ______________________________ (Owner or Authorized Representative's Signature)

PART II QUALITY ASSURANCE REQUIREMENTS

Sampling Organization ______________________________

Analytical Lab NELAC / HRS Certification # ______________________________

Lab Name ______________________________

Address ______________________________

Phone Number (____) ______________________________

Email address (if available) ______________________________

DEP-SOP-001/01
FS 2200 Groundwater Sampling
Form FD 9000-24

GROUNDWATER SAMPLING LOG

SITE NAME:	SITE LOCATION:	
WELL NO:	SAMPLE ID:	DATE:

PURGING DATA

WELL DIAMETER (inches):	TUBING DIAMETER (inches):	WELL SCREEN INTERVAL DEPTH: feet to feet	STATIC DEPTH TO WATER (feet):	PURGE PUMP TYPE OR BAILER:

WELL VOLUME PURGE: 1 WELL VOLUME = (TOTAL WELL DEPTH – STATIC DEPTH TO WATER) X WELL CAPACITY
only fill out if applicable)
= (feet – feet) X gallons/foot = gallons

EQUIPMENT VOLUME PURGE: 1 EQUIPMENT VOL. = PUMP VOLUME + (TUBING CAPACITY X TUBING LENGTH) + FLOW CELL VOLUME
(only fill out if applicable)
= gallons + (gallons/foot X feet) + gallons = gallons

INITIAL PUMP OR TUBING DEPTH IN WELL (feet):	FINAL PUMP OR TUBING DEPTH IN WELL (feet):	PURGING INITIATED AT:	PURGING ENDED AT:	TOTAL VOLUME PURGED (gallons):

TIME	VOLUME PURGED (gallons)	CUMUL. VOLUME PURGED (gallons)	PURGE RATE (gpm)	DEPTH TO WATER (feet)	pH (standard units)	TEMP. (°C)	COND. (µmhos/cm or µS/cm)	DISSOLVED OXYGEN (circle mg/L or % saturation)	TURBIDITY (NTUs)	COLOR (describe)	ODOR (describe)

WELL CAPACITY (Gallons Per Foot): 0.75" = 0.02; 1" = 0.04; 1.25" = 0.06; 2" = 0.16; 3" = 0.37; 4" = 0.65; 5" = 1.02; 6" = 1.47; 12" = 5.88
TUBING INSIDE DIA. CAPACITY (Gal./Ft.): 1/8" = 0.0006; 3/16" = 0.0014; 1/4" = 0.0026; 5/16" = 0.004; 3/8" = 0.006; 1/2" = 0.010; 5/8" = 0.016

SAMPLING DATA

SAMPLED BY (PRINT) / AFFILIATION:	SAMPLER(S) SIGNATURES:	SAMPLING INITIATED AT:	SAMPLING ENDED AT:
PUMP OR TUBING DEPTH IN WELL (feet):	SAMPLE PUMP FLOW RATE (mL per minute):	TUBING MATERIAL CODE:	
FIELD DECONTAMINATION: Y N	FIELD-FILTERED: Y N FILTER SIZE: ______ µm Filtration Equipment Type: ______	DUPLICATE: Y N	

SAMPLE CONTAINER SPECIFICATION				SAMPLE PRESERVATION			INTENDED ANALYSIS AND/OR METHOD	SAMPLING EQUIPMENT CODE
SAMPLE ID CODE	# CONTAINERS	MATERIAL CODE	VOLUME	PRESERVATIVE USED	TOTAL VOL ADDED IN FIELD (mL)	FINAL pH		

REMARKS:

MATERIAL CODES: AG = Amber Glass; CG = Clear Glass; PE = Polyethylene; PP = Polypropylene; S = Silicone; T = Teflon; O = Other (Specify)

SAMPLING/PURGING EQUIPMENT CODES: APP = After Peristaltic Pump; B = Bailer; BP = Bladder Pump; ESP = Electric Submersible Pump; PP = Peristaltic Pump; RFPP = Reverse Flow Peristaltic Pump; SM = Straw Method (Tubing Gravity Drain); VT = Vacuum Trap; O = Other (Specify)

NOTES:1. The above do not constitute all of the information required by Chapter 62-160, F.A.C.

2. STABILIZATION CRITERIA FOR RANGE OF VARIATION OF LAST THREE CONSECUTIVE READINGS (SEE FS 2212, SECTION 3)

pH: ± 0.2 units **Temperature:** ± 0.2 °C **Specific Conductance:** ± 5% **Dissolved Oxygen:** all readings ≤ 20% saturation (see Table FS 2200-2); optionally, ± 0.2 mg/L or ± 10% (whichever is greater) **Turbidity:** all readings ≤ 20 NTU; optionally ± 5 NTU or ± 10% (whichever is greater)

Schedule 1A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Line		Period Amount ($)
1	End of Period Actual Total True-Up for the Period January 2010 - December 2010 (Schedule 2A, Line 5 + 6 + 9)	626,546
2	Estimated/Actual True-Up Amount approved for the period January 2010 - December 2010 (FPSC Order No. PSC-10-0683-FOF-EI)	(234,779)
3	Final True-Up Amount to be refunded/(recovered) in the in the projection period January 2012 - December 2012 (Lines 1 - 2)	861,325

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI EXHIBIT 35
PARTY GULF POWER COMPANY (DIRECT)
DESCRIPTION R. W. DODD (RWD-1)
DATE 11/01/11

Schedule 2A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Current Period True-Up Amount
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	ECRC Revenues (net of Revenue Taxes)	13,323,103	12,212,355	10,477,336	10,053,918	13,542,691	15,280,418	16,552,900	15,722,680	14,583,229	11,020,103	9,793,419	13,072,132	155,634,283
2	True-Up Provision (Order No. PSC-09-0759-FOF-EI)	148,878	148,878	148,878	148,878	148,878	148,878	148,878	148,878	148,878	148,878	148,878	148,878	1,786,538
3	**ECRC Revenues Applicable to Period (Lines 1 + 2)**	13,471,981	12,361,233	10,626,214	10,202,796	13,691,569	15,429,296	16,701,778	15,871,558	14,732,107	11,168,981	9,942,297	13,221,010	157,420,821
4	Jurisdictional ECRC Costs													
	a O & M Activities (Schedule 5E, Line 9)	4,460,559	2,390,947	2,329,012	1,368,033	2,367,264	1,809,330	2,820,229	3,264,049	2,802,695	2,156,003	2,527,589	4,645,818	32,941,528
	b Capital Investment Projects (Schedule 7E, Line 9)	9,566,483	9,798,537	9,806,258	9,831,327	9,862,037	9,904,292	9,913,380	13,956,477	10,353,170	10,333,178	10,296,380	10,263,256	123,884,775
	c **Total Jurisdictional ECRC Costs**	14,027,042	12,189,484	12,135,270	11,199,360	12,229,301	11,713,622	12,733,609	17,220,526	13,155,865	12,489,181	12,823,969	14,909,074	156,826,303
5	**Over/(Under) Recovery (Line 3 - Line 4c)**	(555,061)	171,749	(1,509,056)	(996,564)	1,462,268	3,715,674	3,968,169	(1,348,968)	1,576,242	(1,320,200)	(2,881,672)	(1,688,064)	594,518
6	Interest Provision (Schedule 3E, Line 10)	1,867	1,854	1,754	1,578	2,073	3,212	3,905	3,731	3,532	3,321	2,853	2,348	32,028
7	Beginning Balance True-Up & Interest Provision													
	a Actual Total for True-Up Period 2009	10,149,912	9,447,840	9,472,565	7,816,384	6,672,520	7,987,983	11,557,991	15,381,187	13,887,072	15,317,968	13,852,211	10,824,514	10,149,912
	b Final True-Up from January 2008 - December 2008 (Order No. PSC-09-0759-FOF-EI)	1,381,411	1,381,411	1,381,411	1,381,411	1,381,411	1,381,411	1,381,411	1,381,411	1,381,411	1,381,411	1,381,411	1,381,411	1,381,411
8	True-Up Collected/(Refunded) (see Line 2)	(148,878)	(148,878)	(148,878)	(148,878)	(148,878)	(148,878)	(148,878)	(148,878)	(148,878)	(148,878)	(148,878)	(148,878)	(1,786,538)
9	Adjustments													
10	End of Period Total True-Up (Lines 5 + 6 + 7a + 7b + 8)	10,829,251	10,853,976	9,197,795	8,053,931	9,369,394	12,939,402	16,762,598	15,268,483	16,699,379	15,233,622	12,205,925	10,371,331	10,371,331

Schedule 3A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Interest Provision
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Beg. True-Up Amount (Schedule 2E, Lines 7a + 7b)	11,531,323	10,829,251	10,853,976	9,197,795	8,053,931	9,369,394	12,939,402	16,762,598	15,268,483	16,699,379	15,233,622	12,205,925	
2	Ending True-Up Amount Before Interest (Line 1 + Schedule 2E, Lines 5 + 8)	10,827,384	10,852,122	9,196,041	8,052,353	9,367,321	12,936,190	16,758,693	15,264,752	16,695,847	15,230,301	12,203,072	10,368,983	
3	Total of Beginning & Ending True-up (Lines 1 + 2)	22,358,707	21,681,373	20,050,017	17,250,148	17,421,252	22,305,585	29,698,096	32,027,351	31,964,330	31,929,680	27,436,694	22,574,908	
4	Average True-Up Amount (Line 3 x 1/2)	11,179,353	10,840,686	10,025,009	8,625,074	8,710,626	11,152,792	14,849,048	16,013,675	15,982,165	15,964,840	13,718,347	11,287,454	
5	Interest Rate (First Day of Reporting Business Month)	0.002000	0.002000	0.002100	0.002100	0.002300	0.003400	0.003500	0.002800	0.002800	0.002500	0.002500	0.002500	
6	Interest Rate (First Day of Subsequent Business Month)	0.002000	0.002100	0.002100	0.002300	0.003400	0.003500	0.002800	0.002800	0.002500	0.002500	0.002500	0.002500	
7	Total of Beginning and Ending Interest Rates (Line 5 + Line 6)	0.004000	0.004100	0.004200	0.004400	0.005700	0.006900	0.006300	0.005600	0.005300	0.005000	0.005000	0.005000	
8	Average Interest Rate (Line 7 x 1/2)	0.002000	0.002050	0.002100	0.002200	0.002850	0.003450	0.003150	0.002800	0.002650	0.002500	0.002500	0.002500	
9	Monthly Average Interest Rate (Line 8 x 1/12)	0.000167	0.000171	0.000175	0.000183	0.000238	0.000288	0.000263	0.000233	0.000221	0.000208	0.000208	0.000208	
10	Interest Provision for the Month (Line 4 x Line 9)	1,867	1,854	1,754	1,578	2,073	3,212	3,905	3,731	3,532	3,321	2,853	2,348	32,028

Schedule 4A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Variance Report of O & M Activities
(in Dollars)

Line		(1) Actual	(2) Estimated/ Actual	(3) Variance Amount	(4) Variance Percent
1	Description of O & M Activities				
	.1 Sulfur	0	0	0	0.0 %
	.2 Air Emission Fees	714,504	714,504	0	0.0 %
	.3 Title V	105,955	122,446	(16,491)	(13.5) %
	.4 Asbestos Fees	0	1,500	(1,500)	(100.0) %
	.5 Emission Monitoring	523,001	555,646	(32,645)	(5.9) %
	.6 General Water Quality	653,709	652,465	1,244	0.2 %
	.7 Groundwater Contamination Investigation	1,592,493	1,609,149	(16,656)	(1.0) %
	.8 State NPDES Administration	42,394	42,248	146	0.3 %
	.9 Lead and Copper Rule	17,995	21,096	(3,101)	(14.7) %
	.10 Env Auditing/Assessment	6,945	7,168	(223)	(3.1) %
	.11 General Solid & Hazardous Waste	1,070,538	512,481	558,057	108.9 %
	.12 Above Ground Storage Tanks	29,340	87,555	(58,215)	(66.5) %
	.13 Low Nox	0	0	0	0.0 %
	.14 Ash Pond Diversion Curtains	811,099	739,668	71,431	9.7 %
	.15 Mercury Emissions	0	0	0	0.0 %
	.16 Sodium Injection	81,807	244,362	(162,555)	(66.5) %
	.17 Gulf Coast Ozone Study	0	0	0	0.0 %
	.18 SPCC Substation Project	0	0	0	0.0 %
	.19 FDEP NOX Reduction Agreement	2,090,992	2,673,456	(582,464)	(21.8) %
	.20 CAIR/CAMR/CAVR Compliance Program	15,004,364	15,033,520	(29,156)	(0.2) %
	.21 MACT ICR	281,430	284,041	(2,611)	(0.9) %
	.22 CRIST WATER CONSERVATION	6,050	0	6,050	100.0 %
	.23 Mercury Allowances	0	0	0	0.0 %
	.24 Annual NOx Allowances	8,302,302	8,746,048	(443,746)	(5.1) %
	.25 Seasonal NOx Allowances	222,894	213,297	9,597	4.5 %
	.26 SO2 Allowances	2,524,008	2,741,254	(217,246)	(7.9) %
2	Total O & M Activities	34,081,820	35,001,904	(920,084)	(2.6) %
3	Recoverable Costs Allocated to Energy	30,662,356	32,068,242	(1,405,886)	(4.4) %
4	Recoverable Costs Allocated to Demand	3,419,464	2,933,662	485,802	16.6 %

Notes:

Column (1) is the End of Period Totals on Schedule 5E
Column (2) is the approved Projected amount in accordance with FPSC Order No. PSC-09-0759-FOF-EI
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

O & M Activities
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period 12-Month	Method of Classification Demand	Method of Classification Energy
1	Description of O & M Activities															
	.1 Sulfur	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.2 Air Emission Fees	-	590,130	-	-	-	-	-	-	-	-	-	124,374	714,504	0	714,504
	.3 Title V	8,673	7,961	9,017	8,549	8,650	11,536	6,311	9,118	10,096	8,870	8,769	8,405	105,955	0	105,955
	.4 Asbestos Fees	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.5 Emission Monitoring	35,133	47,195	52,919	43,020	49,181	43,124	36,562	34,730	36,106	45,904	51,043	48,084	523,001	0	523,001
	.6 General Water Quality	39,380	25,228	38,693	176,212	(54,518)	8,835	64,950	156,109	47,978	51,388	49,715	49,739	653,709	653,709	0
	.7 Groundwater Contamination Investigation	72,450	38,714	106,927	84,818	355,812	63,410	89,293	55,668	108,128	105,147	149,524	362,602	1,592,493	1,592,493	0
	.8 State NPDES Administration	-	-	7,578	60	110	-	-	45	101	-	-	34,500	42,394	42,394	0
	.9 Lead and Copper Rule	-	3,529	-	-	-	3,596	-	7,035	-	-	-	3,835	17,995	17,995	0
	.10 Env Auditing/Assessment	-	8	160	-	-	-	-	249	-	10	-	6,518	6,945	6,945	0
	.11 General Solid & Hazardous Waste	19,707	42,309	34,264	45,706	9,480	29,443	29,660	59,793	3,869	63,957	128,244	604,106	1,070,538	1,070,538	0
	.12 Above Ground Storage Tanks	615	1,532	5,168	2,025	526	3,004	487	2,548	1,199	2,382	506	9,348	29,340	29,340	0
	.13 Low Nox	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.14 Ash Pond Diversion Curtains	(591)	45,625	34,919	(19,919)	246,315	108,319	113,556	96,999	95,154	89,850	-	872	811,099	0	811,099
	.15 Mercury Emissions	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.16 Sodium Injection	463	8,672	13,951	6,731	-	7,556	27	10,284	9,945	15,419	514	8,245	81,807	0	81,807
	.17 Gulf Coast Ozone Study	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.18 SPCC Substation Project	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.19 FDEP NOX Reduction Agreement	188,946	214,306	189,457	222,343	187,250	126,394	201,313	202,220	220,219	138,503	112,423	87,618	2,090,992	0	2,090,992
	.20 CAIR/CAMR/CAVR Compliance Program	1,503,080	970,486	946,522	639,769	744,602	582,981	1,199,746	1,552,990	1,383,998	1,108,436	1,530,203	2,841,551	15,004,364	0	15,004,364
	.21 MACT ICR	41	457	14,583	4,247	252,787	11,926	1,930	(5,598)	605	289	-	163	281,430	0	281,430
	.22 CRIST WATER CONSERVATION	-	-	-	-	-	-	-	-	-	-	6,050	-	6,050	6,050	
	.23 Mercury Allowances	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.24 Annual NOx Allowances	2,089,413	314,860	582,855	347,503	401,754	622,893	879,290	897,749	720,558	466,769	458,407	520,251	8,302,302	0	8,302,302
	.25 Seasonal NOx Allowances	-	-	-	-	38,563	43,619	49,177	47,243	41,142	3,150	-	-	222,894	0	222,894
	.26 SO2 Allowances	672,851	163,377	373,034	(147,159)	203,335	201,763	237,729	245,656	214,451	127,415	121,794	109,762	2,524,008	0	2,524,008
2	Total of O & M Activities	4,630,161	2,474,389	2,410,047	1,413,905	2,443,847	1,868,399	2,910,031	3,372,838	2,893,549	2,227,489	2,617,192	4,819,973	34,081,820	3,419,464	30,662,356
3	Recoverable Costs Allocated to Energy	4,498,009	2,363,069	2,217,257	1,105,084	2,132,437	1,760,111	2,725,641	3,091,391	2,732,274	2,004,605	2,283,153	3,749,325	30,662,356		
4	Recoverable Costs Allocated to Demand	132,152	111,320	192,790	308,821	311,410	108,288	184,390	281,447	161,275	222,884	334,039	1,070,648	3,419,464		
5	Retail Energy Jurisdictional Factor	0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	0.9630946		
6	Retail Demand Jurisdictional Factor	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160		
7	Jurisdictional Energy Recoverable Costs (A)	4,333,136	2,283,610	2,143,121	1,070,263	2,066,997	1,704,917	2,642,437	2,992,673	2,647,191	1,941,094	2,205,504	3,613,482	29,644,425		
8	Jurisdictional Demand Recoverable Costs (B)	127,423	107,337	185,891	297,770	300,267	104,413	177,792	271,376	155,504	214,909	322,085	1,032,336	3,297,103		
9	Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8)	4,460,559	2,390,947	2,329,012	1,368,033	2,367,264	1,809,330	2,820,229	3,264,049	2,802,695	2,156,003	2,527,589	4,645,818	32,941,528		

Notes:
(A) Line 3 x Line 5 x line loss multiplier
(B) Line 4 x Line 6

Schedule 6A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

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

Line		(1) Actual	(2) Estimated/ Actual	(3) Variance Amount	(4) Variance Percent	
1	Description of Investment Projects					
	.1 Air Quality Assurance Testing	41,066	39,220	1,846	4.7	%
	.2 Crist 5, 6 & 7 Precipitator Projects	1,836,851	1,846,580	(9,729)	(0.5)	%
	.3 Crist 7 Flue Gas Conditioning	168,245	168,240	5	0.0	%
	.4 Low NOx Burners, Crist 6 & 7	2,012,708	2,012,558	150	0.0	%
	.5 CEMS - Plants Crist, Scholz, Smith, & Daniel	1,137,532	1,140,729	(3,197)	(0.3)	%
	.6 Sub. Contam. Mobile Groundwater Treat. Sys.	97,650	97,660	(10)	(0.0)	%
	.7 Raw Water Well Flowmeters - Plants Crist & Smith	27,364	27,357	7	0.0	%
	.8 Crist Cooling Tower Cell	59,019	59,021	(2)	(0.0)	%
	.9 Crist 1-5 Dechlorination	27,051	27,048	3	0.0	%
	.10 Crist Diesel Fuel Oil Remediation	6,822	6,819	3	0.0	%
	.11 Crist Bulk Tanker Unload Sec Contain Struc	9,000	8,997	3	0.0	%
	.12 Crist IWW Sampling System	5,248	5,247	1	0.0	%
	.13 Sodium Injection System	48,904	48,895	9	0.0	%
	.14 Smith Stormwater Collection System	264,850	264,727	123	0.0	%
	.15 Smith Waste Water Treatment Facility	36,677	36,668	9	0.0	%
	.16 Daniel Ash Management Project	2,114,434	2,114,732	(298)	(0.0)	%
	.17 Smith Water Conservation	16,897	27,269	(10,372)	(38.0)	%
	.18 Underground Fuel Tank Replacement	0	0	0	0.0	%
	.19 Crist FDEP Agreement for Ozone Attainment	17,575,099	17,568,221	6,878	0.0	%
	.20 SPCC Compliance	125,849	125,832	17	0.0	%
	.21 Crist Common FTIR Monitor	7,849	7,847	2	0.0	%
	.22 Precipitator Upgrades for CAM Compliance	4,078,532	4,077,611	921	0.0	%
	.23 Plant Groundwater Investigation	0	0	0	0.0	%
	.24 Crist Water Conservation	2,131,414	2,102,037	29,377	1.4	%
	.25 Plant NPDES Permit Compliance Projects	796,093	796,223	(130)	(0.0)	%
	.26 CAIR/CAMR/CAVR Compliance	93,754,384	93,798,274	(43,890)	(0.0)	%
	.27 General Water Quality	8,598	8,598	0	0.0	%
	.28 Mercury Allowances	0	0	0	0.0	%
	.29 Annual Nox Allowances	572,447	569,256	3,191	0.6	%
	.30 Seasonal Nox Allowances	13,203	13,285	(82)	(0.6)	%
	.31 SO2 Allowances	1,116,784	1,113,726	3,058	0.3	%
2	Total Investment Projects - Recoverable Costs	128,090,570	128,112,677	(22,107)	(0.0)	%
3	Recoverable Costs Allocated to Energy	122,804,142	122,843,536	(39,394)	(0.0)	%
4	Recoverable Costs Allocated to Demand	5,286,428	5,269,141	17,287	0.3	%

Notes:
Column (1) is the End of Period Totals on Schedule 7E
Column (2) is the approved Projected amount in accordance with FPSC Order No. PSC-09-0759-FOF-EI
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Docket No. 110007-EI
ECRC 2011 Final True-Up
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Schedule 7A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Capital Investment Projects - Recoverable Costs
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount	Method of Classification Demand	Method of Classification Energy
1	Description of Investment Projects (A)															
	.1 Air Quality Assurance Testing	3,405	3,379	3,355	3,330	3,305	3,280	3,256	3,232	3,206	3,182	3,772	4,364	41,066	0	41,066
	.2 Crist 5, 6 & 7 Precipitator Projects	151,713	151,259	150,919	150,735	150,598	150,671	150,818	168,255	152,783	152,820	152,979	153,301	1,836,851	0	1,836,851
	.3 Crist 7 Flue Gas Conditioning	14,022	14,020	14,018	14,017	14,014	14,013	14,010	14,083	14,015	14,013	14,011	14,009	168,245	0	168,245
	.4 Low NOx Burners, Crist 6 & 7	166,788	166,560	166,331	166,102	165,873	165,644	165,416	183,297	167,050	166,799	166,549	166,299	2,012,708	0	2,012,708
	.5 CEMS - Plants Crist, Scholz, Smith, & Daniel	89,634	90,749	92,438	92,475	92,361	92,302	88,780	101,973	92,023	94,773	101,452	108,572	1,137,532	0	1,137,532
	.6 Sub. Contam. Mobile Groundwater Treat. Sys.	8,381	8,363	8,346	8,328	8,312	8,294	8,277	7,039	8,102	8,085	8,070	8,053	97,650	90,139	7,511
	.7 Raw Water Well Flowmeters - Plants Crist & Smith	2,216	2,209	2,204	2,199	2,193	2,187	2,181	2,968	2,262	2,255	2,248	2,242	27,364	25,260	2,104
	.8 Crist Cooling Tower Cell	4,920	4,918	4,917	4,916	4,914	4,912	4,911	4,964	4,914	4,911	4,912	4,910	59,019	54,479	4,540
	.9 Crist 1-5 Dechlorination	2,223	2,215	2,207	2,199	2,193	2,184	2,175	2,777	2,232	2,224	2,215	2,207	27,051	24,970	2,081
	.10 Crist Diesel Fuel Oil Remediation	561	560	558	556	554	553	551	687	563	562	559	558	6,822	6,297	525
	.11 Crist Bulk Tanker Unload Sec Contain Struc	740	737	735	732	729	727	724	924	743	739	736	734	9,000	8,307	693
	.12 Crist IWW Sampling System	431	430	429	426	425	424	422	539	433	431	430	428	5,248	4,845	403
	.13 Sodium Injection System	3,989	3,980	3,970	3,961	3,952	3,943	3,933	5,056	4,046	4,035	4,025	4,014	48,904	0	48,904
	.14 Smith Stormwater Collection System	20,579	20,525	20,470	20,416	20,361	20,306	20,252	34,974	21,850	21,778	21,706	21,633	264,850	244,477	20,373
	.15 Smith Waste Water Treatment Facility	2,960	2,958	2,954	2,949	2,946	2,943	2,940	3,887	3,042	3,037	3,033	3,028	36,677	33,855	2,822
	.16 Daniel Ash Management Project	185,297	184,045	182,307	182,086	181,587	181,254	181,014	137,968	175,257	174,906	174,575	174,138	2,114,434	1,951,784	162,650
	.17 Smith Water Conservation	1,336	1,333	1,331	1,328	1,326	1,322	1,320	2,030	1,398	1,395	1,391	1,387	16,897	15,596	1,301
	.18 Underground Fuel Tank Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.19 Crist FDEP Agreement for Ozone Attainment	1,448,886	1,445,342	1,441,652	1,437,969	1,434,434	1,430,890	1,427,345	1,712,820	1,454,284	1,451,013	1,446,513	1,443,951	17,575,099	0	17,575,099
	.20 SPCC Compliance	10,387	10,364	10,340	10,318	10,294	10,271	10,248	12,108	10,418	10,393	10,367	10,341	125,849	116,170	9,679
	.21 Crist Common FTIR Monitor	648	646	644	643	642	640	638	762	649	648	645	644	7,849	0	7,849
	.22 Precipitator Upgrades for CAM Compliance	330,048	329,383	328,718	328,053	327,388	326,723	326,058	436,633	337,577	336,781	335,984	335,186	4,078,532	0	4,078,532
	.23 Plant Groundwater Investigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.24 Crist Water Conservation	41,603	107,245	116,022	127,670	160,882	207,628	213,317	239,866	225,806	229,659	230,635	231,081	2,131,414	1,967,459	163,955
	.25 Crist Condenser Tubes	65,653	65,503	65,353	65,205	65,055	64,904	64,754	76,485	65,826	65,792	65,815	65,748	796,093	734,853	61,240
	.26 CAIR/CAMR/CAVR Compliance	7,214,358	7,373,199	7,378,614	7,384,340	7,376,815	7,375,153	7,378,267	11,120,095	7,804,599	7,795,314	7,784,891	7,768,739	93,754,384	0	93,754,384
	.27 General Water Quality	745	739	734	729	724	719	714	709	704	698	694	689	8,598	7,937	661
	.28 Mercury Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.29 Annual Nox Allowances	52,135	47,080	46,796	42,407	46,374	59,252	62,379	53,996	46,363	40,763	36,398	38,504	572,447	0	572,447
	.30 Seasonal Nox Allowances	2,024	2,024	2,024	2,024	1,841	1,454	1,016	561	169	0	22	44	13,203	0	13,203
	.31 SO2 Allowances	104,509	100,564	98,034	96,825	96,415	94,481	92,387	90,106	87,936	86,324	85,147	84,056	1,116,784	0	1,116,784
2	Total Investment Projects - Recoverable Costs	9,930,191	10,140,329	10,146,420	10,152,938	10,176,507	10,227,074	10,228,103	14,418,794	10,688,250	10,673,330	10,659,774	10,648,860	128,090,570	5,286,428	122,804,142
3	Recoverable Costs Allocated to Energy	9,608,930	9,759,889	9,759,737	9,755,963	9,749,590	9,757,572	9,753,826	13,931,477	10,204,975	10,186,992	10,172,956	10,162,235	122,804,142		
4	Recoverable Costs Allocated to Demand	321,261	380,440	386,683	396,975	426,917	469,502	474,277	487,317	483,275	486,338	486,818	486,625	5,286,428		
5	Retail Energy Jurisdictional Factor	0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946			
6	Retail Demand Jurisdictional Factor	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160			
7	Jurisdictional Energy Recoverable Costs (B)	9,256,718	9,431,711	9,433,412	9,448,557	9,450,397	9,451,591	9,456,075	13,486,599	9,887,189	9,864,243	9,826,982	9,794,044	118,787,518		
8	Jurisdictional Demand Recoverable Costs (C)	309,765	366,826	372,846	382,770	411,640	452,701	457,305	469,878	465,981	468,935	469,398	469,212	5,097,257		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	9,566,483	9,798,537	9,806,258	9,831,327	9,862,037	9,904,292	9,913,380	13,956,477	10,353,170	10,333,178	10,296,380	10,263,256	123,884,775		

Notes:

(A) Pages 1-27 of Schedule 8E, Line 9. Pages 28-31 of Schedule 8E, Line 6
(B) Line 3 x Line 5 x Line loss multiplier
(C) Line 4 x Line 6

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Air Quality Assurance Testing
P.E.s 1006 & 1244
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	130,539	(21)	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	130,518	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	220,294	350,812	
3	Less: Accumulated Depreciation (C)	(136,152)	(138,775)	(141,398)	(144,021)	(146,644)	(149,267)	(151,890)	(154,513)	(157,136)	(159,759)	(162,382)	(165,005)	(167,628)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	130,539	0	
5	Net Investment (Lines 2 + 3 + 4)	84,142	81,519	78,896	76,273	73,650	71,027	68,404	65,781	63,158	60,535	57,912	185,828	183,184	
6	Average Net Investment		82,831	80,208	77,585	74,962	72,339	69,716	67,093	64,470	61,847	59,224	121,870	184,506	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		609	589	570	551	531	512	493	474	454	435	895	1,356	7,469
	b Debt Component (Line 6 x Debt Component x 1/12)		173	167	162	156	151	145	140	135	129	124	254	385	2,121
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		2,623	2,623	2,623	2,623	2,623	2,623	2,623	2,623	2,623	2,623	2,623	2,623	31,476
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		3,405	3,379	3,355	3,330	3,305	3,280	3,256	3,232	3,206	3,182	3,772	4,364	41,066
	a Recoverable Costs Allocated to Energy		3,405	3,379	3,355	3,330	3,305	3,280	3,256	3,232	3,206	3,182	3,772	4,364	41,066
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		3,280	3,265	3,243	3,225	3,204	3,177	3,157	3,129	3,106	3,081	3,644	4,206	39,717
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		3,280	3,265	3,243	3,225	3,204	3,177	3,157	3,129	3,106	3,081	3,644	4,206	39,717

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Applicable depreciation rate or rates.
(F) PE 1244 7 year amorization; PE 1006 fully amortized
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 5, 6 & 7 Precipitator Projects
P.E.s 1038, 1119, 1216, 1243, 1249
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	335	19,148	26,725	29,297	67,056	40,275	39,063	37,811	54,789	61,708	95,537	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	279	5,225	6,650	5,500	10,586	9,837	5,392	6,520	10,112	8,336	4,166	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	13,909,529	13,909,529	13,909,529	13,909,529	13,909,529	13,909,529	13,909,529	13,909,529	13,909,529	13,909,529	13,909,529	13,909,529	13,909,529	
3	Less: Accumulated Depreciation (C)	(2,941,737)	(2,990,209)	(3,038,402)	(3,081,648)	(3,123,470)	(3,166,441)	(3,204,326)	(3,242,961)	(3,303,573)	(3,347,716)	(3,388,267)	(3,430,594)	(3,477,091)	
4	CWIP - Non Interest Bearing	0	0	335	19,483	46,208	75,505	142,561	182,836	221,899	259,710	314,499	376,207	471,744	
5	Net Investment (Lines 2 + 3 + 4)	10,967,792	10,919,320	10,871,462	10,847,364	10,832,267	10,818,593	10,847,764	10,849,404	10,827,855	10,821,523	10,835,761	10,855,142	10,904,182	
6	Average Net Investment		10,943,556	10,895,391	10,859,413	10,839,816	10,825,430	10,833,179	10,848,584	10,838,630	10,824,689	10,828,642	10,845,452	10,879,662	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		80,402	80,048	79,784	79,640	79,534	79,591	79,705	79,631	79,529	79,558	79,682	79,932	957,036
	b Debt Component (Line 6 x Debt Component x 1/12)		22,839	22,739	22,664	22,623	22,593	22,609	22,641	22,620	22,591	22,599	22,634	22,706	271,858
8	Investment Expenses														
	a Depreciation (E)		37,097	37,097	37,096	37,097	37,096	37,096	37,097	64,916	40,574	40,574	40,574	40,574	486,888
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		11,375	11,375	11,375	11,375	11,375	11,375	11,375	1,088	10,089	10,089	10,089	10,089	121,069
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		151,713	151,259	150,919	150,735	150,598	150,671	150,818	168,255	152,783	152,820	152,979	153,301	1,836,851
	a Recoverable Costs Allocated to Energy		151,713	151,259	150,919	150,735	150,598	150,671	150,818	168,255	152,783	152,820	152,979	153,301	1,836,851
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		146,152	146,173	145,873	145,986	145,976	145,946	146,214	162,882	148,025	147,978	147,776	147,747	1,776,728
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		146,152	146,173	145,873	145,986	145,976	145,946	146,214	162,882	148,025	147,978	147,776	147,747	1,776,728

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.5% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 7 Flue Gas Conditioning
P.E. 1228
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	1,464,826	1,464,622	1,464,418	1,464,214	1,464,010	1,463,806	1,463,602	1,463,398	1,463,120	1,462,907	1,462,694	1,462,481	1,462,268	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	1,464,826	1,464,622	1,464,418	1,464,214	1,464,010	1,463,806	1,463,602	1,463,398	1,463,120	1,462,907	1,462,694	1,462,481	1,462,268	
6	Average Net Investment		1,464,724	1,464,520	1,464,316	1,464,112	1,463,908	1,463,704	1,463,500	1,463,259	1,463,014	1,462,801	1,462,588	1,462,375	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		10,761	10,760	10,758	10,757	10,755	10,754	10,752	10,751	10,749	10,747	10,746	10,744	129,034
	b Debt Component (Line 6 x Debt Component x 1/12)		3,057	3,056	3,056	3,056	3,055	3,055	3,054	3,054	3,053	3,053	3,052	3,052	36,653
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		204	204	204	204	204	204	204	278	213	213	213	213	2,558
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		14,022	14,020	14,018	14,017	14,014	14,013	14,010	14,083	14,015	14,013	14,011	14,009	168,245
	a Recoverable Costs Allocated to Energy		14,022	14,020	14,018	14,017	14,014	14,013	14,010	14,083	14,015	14,013	14,011	14,009	168,245
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		13,508	13,549	13,549	13,575	13,584	13,574	13,582	13,633	13,579	13,569	13,534	13,501	162,737
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		13,508	13,549	13,549	13,575	13,584	13,574	13,582	13,633	13,579	13,569	13,534	13,501	162,737

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.5% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burners, Crist 6 & 7
P.E.s 1234, 1236, 1242, 1284
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	
3	Less: Accumulated Depreciation (C)	6,021,775	5,997,511	5,973,247	5,948,983	5,924,719	5,900,455	5,876,191	5,851,927	5,809,467	5,782,928	5,756,389	5,729,850	5,703,311	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	15,119,699	15,095,435	15,071,171	15,046,907	15,022,643	14,998,379	14,974,115	14,949,851	14,907,391	14,880,852	14,854,313	14,827,774	14,801,235	
6	Average Net Investment		15,107,567	15,083,303	15,059,039	15,034,775	15,010,511	14,986,247	14,961,983	14,928,621	14,894,122	14,867,583	14,841,044	14,814,505	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		110,995	110,817	110,639	110,460	110,282	110,104	109,926	109,681	109,427	109,231	109,037	108,842	1,319,441
	b Debt Component (Line 6 x Debt Component x 1/12)		31,529	31,479	31,428	31,378	31,327	31,276	31,226	31,156	31,084	31,029	30,973	30,918	374,803
8	Investment Expenses														
	a Depreciation (E)		24,264	24,264	24,264	24,264	24,264	24,264	24,264	42,460	26,539	26,539	26,539	26,539	318,464
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		166,788	166,560	166,331	166,102	165,873	165,644	165,416	183,297	167,050	166,799	166,549	166,299	2,012,708
	a Recoverable Costs Allocated to Energy		166,788	166,560	166,331	166,102	165,873	165,644	165,416	183,297	167,050	166,799	166,549	166,299	2,012,708
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		160,674	160,959	160,770	160,868	160,783	160,450	160,366	177,444	161,848	161,514	160,885	160,274	1,946,835
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		160,674	160,959	160,770	160,868	160,783	160,450	160,366	177,444	161,848	161,514	160,885	160,274	1,946,835

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.5% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: CEMS - Plants Crist, Scholz, Smith, & Daniel
P.E.s 1001, 1154, 1164, 1217, 1240, 1245, 1247, 1256, 1283, 1286, 1289, 1290, 1311, 1316, 1323, 1324, 1357, 1364, 1440, 1441, 1442, 1444, 1454, 1459, 1460, 1558, 1570, 1658, 1829 & 1830
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		51,788	215,653	28,393	1,476	5,926	10,436	29,397	169,709	116,651	493,234	950,917	586,196	
	b Clearings to Plant		51,788	215,653	28,393	1,476	5,932	3,132	(2,512)	619	1,758	(1,216)	369	2,354,383	
	c Retirements		0	0	0	0	0	1,342,894	0	0	0	0	0	0	
	d Cost of Removal		0	0	2,012	1,158	35	10	0	0	0	0	0	0	
	e Salvage		0	0	7,500	1,150	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	5,844,907	5,896,695	6,112,348	6,140,741	6,142,217	6,148,149	4,808,387	4,805,875	4,806,494	4,808,252	4,807,036	4,807,405	7,161,788	
3	Less: Accumulated Depreciation (C)	1,860,741	1,845,270	1,829,799	1,808,127	1,791,876	1,775,648	3,102,272	3,089,565	3,064,425	3,050,401	3,036,372	3,022,343	3,008,313	
4	CWIP - Non Interest Bearing	0	0	0	0	0	(6)	7,298	39,207	208,297	323,190	817,640	1,768,188	1	
5	Net Investment (Lines 2 + 3 + 4)	7,705,648	7,741,965	7,942,147	7,948,868	7,934,093	7,923,791	7,917,957	7,934,647	8,079,216	8,181,843	8,661,048	9,597,936	10,170,102	
6	Average Net Investment		7,723,807	7,842,056	7,945,508	7,941,481	7,928,942	7,920,874	7,926,302	8,006,932	8,130,530	8,421,446	9,129,492	9,884,019	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		56,747	57,616	58,376	58,346	58,254	58,195	58,235	58,827	59,735	61,872	67,074	72,618	725,895
	b Debt Component (Line 6 x Debt Component x 1/12)		16,120	16,366	16,582	16,574	16,548	16,531	16,542	16,710	16,968	17,576	19,053	20,628	206,198
8	Investment Expenses														
	a Depreciation (E)		15,236	15,236	15,949	16,024	16,028	16,045	12,472	24,905	13,789	13,794	13,794	13,795	187,067
	b Amortization (F)		235	235	235	235	235	235	235	235	235	235	235	235	2,820
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		1,296	1,296	1,296	1,296	1,296	1,296	1,296	1,296	1,296	1,296	1,296	1,296	15,552
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		89,634	90,749	92,438	92,475	92,361	92,302	88,780	101,973	92,023	94,773	101,452	108,572	1,137,532
	a Recoverable Costs Allocated to Energy		89,634	90,749	92,438	92,475	92,361	92,302	88,780	101,973	92,023	94,773	101,452	108,572	1,137,532
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		86,348	87,698	89,347	89,561	89,527	89,408	86,070	98,717	89,157	91,770	98,002	104,638	1,100,243
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		86,348	87,698	89,347	89,561	89,527	89,408	86,070	98,717	89,157	91,770	98,002	104,638	1,100,243

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning Balances: Crist, $2,611,952; Scholz $916,802; Smith $1,734,877; Daniel $581,276. Ending Balances: Crist, $3,928,834; Scholz $916,802; Smith $1,734,877; Daniel $581,276.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Crist: 3.5%; Smith 3.3%; Scholz 4.1%; Daniel 2.8% annually
(F) PE 1364 & 1658 have a 7 year amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Schedule 8A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Sub. Contam. Mobile Groundwater Treat. Sys.
P.E. 1007, 3400, & 3412
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	
3	Less: Accumulated Depreciation (C)	(223,367)	(225,203)	(227,039)	(228,875)	(230,711)	(232,547)	(234,383)	(236,219)	(236,829)	(238,512)	(240,195)	(241,878)	(243,561)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	694,657	692,821	690,985	689,149	687,313	685,477	683,641	681,805	681,195	679,512	677,829	676,146	674,463	
6	Average Net Investment		693,739	691,903	690,067	688,231	686,395	684,559	682,723	681,500	680,354	678,671	676,988	675,305	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		5,097	5,083	5,070	5,056	5,043	5,029	5,016	5,007	4,999	4,986	4,974	4,961	60,321
	b Debt Component (Line 6 x Debt Component x 1/12)		1,448	1,444	1,440	1,436	1,433	1,429	1,425	1,422	1,420	1,416	1,413	1,409	17,135
8	Investment Expenses														
	a Depreciation (E)		1,836	1,836	1,836	1,836	1,836	1,836	1,836	610	1,683	1,683	1,683	1,683	20,194
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		8,381	8,363	8,346	8,328	8,312	8,294	8,277	7,039	8,102	8,085	8,070	8,053	97,650
	a Recoverable Costs Allocated to Energy		645	643	642	641	639	638	637	541	623	622	621	619	7,511
	b Recoverable Costs Allocated to Demand		7,736	7,720	7,704	7,687	7,673	7,656	7,640	6,498	7,479	7,463	7,449	7,434	90,139
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		621	621	621	621	619	618	618	524	604	602	600	597	7,266
13	Retail Demand-Related Recoverable Costs (I)		7,459	7,444	7,428	7,412	7,398	7,382	7,367	6,265	7,211	7,196	7,182	7,168	86,912
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		8,080	8,065	8,049	8,033	8,017	8,000	7,985	6,789	7,815	7,798	7,782	7,765	94,178

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Part of PE 1007 depreciable at 2.2% annually, PEs 3400 and 3412 depreciable at 2.2% annually
(F) The amortizable portion of PE 1007 is fully amortized
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Raw Water Well Flowmeters - Plants Crist & Smith
P.E. 1155 & 1606
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	
3	Less: Accumulated Depreciation (C)	(70,820)	(71,414)	(72,008)	(72,602)	(73,196)	(73,790)	(74,384)	(74,978)	(76,368)	(77,061)	(77,754)	(78,447)	(79,140)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	172,153	171,559	170,965	170,371	169,777	169,183	168,589	167,995	166,605	165,912	165,219	164,526	163,833	
6	Average Net Investment		171,856	171,262	170,668	170,074	169,480	168,886	168,292	167,300	166,259	165,566	164,873	164,180	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,263	1,258	1,254	1,250	1,245	1,241	1,236	1,229	1,222	1,216	1,211	1,206	14,831
	b Debt Component (Line 6 x Debt Component x 1/12)		359	357	356	355	354	352	351	349	347	346	344	343	4,213
8	Investment Expenses														
	a Depreciation (E)		594	594	594	594	594	594	594	1,390	693	693	693	693	8,320
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,216	2,209	2,204	2,199	2,193	2,187	2,181	2,968	2,262	2,255	2,248	2,242	27,364
	a Recoverable Costs Allocated to Energy		170	170	170	169	169	168	168	228	174	173	173	172	2,104
	b Recoverable Costs Allocated to Demand		2,046	2,039	2,034	2,030	2,024	2,019	2,013	2,740	2,088	2,082	2,075	2,070	25,260
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		164	164	164	164	164	163	163	221	169	168	167	166	2,037
13	Retail Demand-Related Recoverable Costs (I)		1,973	1,966	1,961	1,957	1,952	1,947	1,941	2,642	2,013	2,007	2,001	1,996	24,356
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,137	2,130	2,125	2,121	2,116	2,110	2,104	2,863	2,182	2,175	2,168	2,162	26,393

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning and Ending Balances: Crist, $149,950; Smith $93,023.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Crist 3.5%; Smith 3.3% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Cooling Tower Cell
P.E. 1232
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	504,423	504,261	504,099	503,937	503,775	503,613	503,451	503,289	503,072	502,903	502,734	502,565	502,396	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	504,423	504,261	504,099	503,937	503,775	503,613	503,451	503,289	503,072	502,903	502,734	502,565	502,396	
6	Average Net Investment		504,342	504,180	504,018	503,856	503,694	503,532	503,370	503,181	502,988	502,819	502,650	502,481	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		3,705	3,704	3,703	3,702	3,701	3,699	3,698	3,697	3,695	3,693	3,694	3,692	44,383
	b Debt Component (Line 6 x Debt Component x 1/12)		1,053	1,052	1,052	1,052	1,051	1,051	1,051	1,050	1,050	1,049	1,049	1,049	12,609
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		162	162	162	162	162	162	162	217	169	169	169	169	2,027
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		4,920	4,918	4,917	4,916	4,914	4,912	4,911	4,964	4,914	4,911	4,912	4,910	59,019
	a Recoverable Costs Allocated to Energy		378	378	378	378	378	378	378	382	378	378	378	378	4,540
	b Recoverable Costs Allocated to Demand		4,542	4,540	4,539	4,538	4,536	4,534	4,533	4,582	4,536	4,533	4,534	4,532	54,479
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		364	365	365	366	366	366	366	370	366	366	365	364	4,389
13	Retail Demand-Related Recoverable Costs (I)		4,379	4,378	4,377	4,376	4,374	4,372	4,371	4,418	4,374	4,371	4,372	4,370	52,532
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		4,743	4,743	4,742	4,742	4,740	4,738	4,737	4,788	4,740	4,737	4,737	4,734	56,921

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.5% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 1-5 Dechlorination
P.E. 1248
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	
3	Less: Accumulated Depreciation (C)	(155,630)	(156,444)	(157,258)	(158,072)	(158,886)	(159,701)	(160,515)	(161,328)	(162,753)	(163,644)	(164,535)	(165,426)	(166,317)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	149,693	148,879	148,065	147,251	146,437	145,622	144,808	143,995	142,570	141,679	140,788	139,897	139,006	
6	Average Net Investment		149,286	148,472	147,658	146,844	146,030	145,215	144,402	143,283	142,125	141,234	140,343	139,452	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,097	1,091	1,085	1,079	1,073	1,067	1,061	1,053	1,044	1,038	1,031	1,025	12,744
	b Debt Component (Line 6 x Debt Component x 1/12)		312	310	308	306	305	303	301	299	297	295	293	291	3,620
8	Investment Expenses														
	a Depreciation (E)		814	814	814	814	815	814	813	1,425	891	891	891	891	10,687
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,223	2,215	2,207	2,199	2,193	2,184	2,175	2,777	2,232	2,224	2,215	2,207	27,051
	a Recoverable Costs Allocated to Energy		171	170	170	169	169	168	167	214	172	171	170	170	2,081
	b Recoverable Costs Allocated to Demand		2,052	2,045	2,037	2,030	2,024	2,016	2,008	2,563	2,060	2,053	2,045	2,037	24,970
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		165	164	164	164	164	163	162	207	167	166	164	164	2,014
13	Retail Demand-Related Recoverable Costs (I)		1,979	1,972	1,964	1,957	1,952	1,944	1,936	2,471	1,986	1,980	1,972	1,964	24,077
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,144	2,136	2,128	2,121	2,116	2,107	2,098	2,678	2,153	2,146	2,136	2,128	26,091

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.5% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Diesel Fuel Oil Remediation
P.E. 1270
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	
3	Less: Accumulated Depreciation (C)	(28,830)	(29,014)	(29,198)	(29,382)	(29,566)	(29,750)	(29,934)	(30,118)	(30,440)	(30,641)	(30,842)	(31,043)	(31,244)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	40,093	39,909	39,725	39,541	39,357	39,173	38,989	38,805	38,483	38,282	38,081	37,880	37,679	
6	Average Net Investment		40,001	39,817	39,633	39,449	39,265	39,081	38,897	38,644	38,383	38,182	37,981	37,780	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		294	293	291	290	288	287	286	284	282	281	279	278	3,433
	b Debt Component (Line 6 x Debt Component x 1/12)		83	83	83	82	82	82	81	81	80	80	79	79	975
8	Investment Expenses														
	a Depreciation (E)		184	184	184	184	184	184	184	322	201	201	201	201	2,414
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		561	560	558	556	554	553	551	687	563	562	559	558	6,822
	a Recoverable Costs Allocated to Energy		43	43	43	43	43	43	42	53	43	43	43	43	525
	b Recoverable Costs Allocated to Demand		518	517	515	513	511	510	509	634	520	519	516	515	6,297
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		41	42	42	42	42	42	41	51	42	42	42	41	510
13	Retail Demand-Related Recoverable Costs (I)		499	498	497	495	493	492	491	611	501	500	498	497	6,072
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		540	540	539	537	535	534	532	662	543	542	540	538	6,582

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.5% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Bulk Tanker Unload Sec Contain Struc
P.E. 1271
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	
3	Less: Accumulated Depreciation (C)	(51,668)	(51,939)	(52,210)	(52,481)	(52,752)	(53,023)	(53,294)	(53,565)	(54,039)	(54,335)	(54,631)	(54,927)	(55,223)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	49,827	49,556	49,285	49,014	48,743	48,472	48,201	47,930	47,456	47,160	46,864	46,568	46,272	
6	Average Net Investment		49,692	49,421	49,150	48,879	48,608	48,337	48,066	47,693	47,308	47,012	46,716	46,420	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		365	363	361	359	357	355	353	350	348	345	343	341	4,240
	b Debt Component (Line 6 x Debt Component x 1/12)		104	103	103	102	101	101	100	100	99	98	97	97	1,205
8	Investment Expenses														
	a Depreciation (E)		271	271	271	271	271	271	271	474	296	296	296	296	3,555
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		740	737	735	732	729	727	724	924	743	739	736	734	9,000
	a Recoverable Costs Allocated to Energy		57	57	57	56	56	56	56	71	57	57	57	56	693
	b Recoverable Costs Allocated to Demand		683	680	678	676	673	671	668	853	686	682	679	678	8,307
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		55	55	55	54	54	54	54	69	55	55	55	54	669
13	Retail Demand-Related Recoverable Costs (I)		659	656	654	652	649	647	644	822	661	658	655	654	8,011
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		714	711	709	706	703	701	698	891	716	713	710	708	8,680

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.5% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Schedule 8A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Crist IWW Sampling System
P.E. 1275
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	
3	Less: Accumulated Depreciation (C)	(30,629)	(30,788)	(30,947)	(31,106)	(31,265)	(31,424)	(31,583)	(31,742)	(32,020)	(32,194)	(32,368)	(32,542)	(32,716)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	28,914	28,755	28,596	28,437	28,278	28,119	27,960	27,801	27,523	27,349	27,175	27,001	26,827	
6	Average Net Investment		28,835	28,676	28,517	28,358	28,199	28,040	27,881	27,662	27,436	27,262	27,088	26,914	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		212	211	210	208	207	206	205	203	202	200	199	198	2,461
	b Debt Component (Line 6 x Debt Component x 1/12)		60	60	60	59	59	59	58	58	57	57	57	56	700
8	Investment Expenses														
	a Depreciation (E)		159	159	159	159	159	159	159	278	174	174	174	174	2,087
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		431	430	429	426	425	424	422	539	433	431	430	428	5,248
	a Recoverable Costs Allocated to Energy		33	33	33	33	33	33	32	41	33	33	33	33	403
	b Recoverable Costs Allocated to Demand		398	397	396	393	392	391	390	498	400	398	397	395	4,845
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		32	32	32	32	32	32	31	40	32	32	32	32	391
13	Retail Demand-Related Recoverable Costs (I)		384	383	382	379	378	377	376	480	386	384	383	381	4,673
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		416	415	414	411	410	409	407	520	418	416	415	413	5,064

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.5% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Sodium Injection System
P.E. 1214 & 1413
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	
3	Less: Accumulated Depreciation (C)	(71,762)	(72,743)	(73,724)	(74,705)	(75,686)	(76,667)	(77,648)	(78,629)	(80,747)	(81,870)	(82,993)	(84,116)	(85,239)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	319,357	318,376	317,395	316,414	315,433	314,452	313,471	312,490	310,372	309,249	308,126	307,003	305,880	
6	Average Net Investment		318,867	317,886	316,905	315,924	314,943	313,962	312,981	311,431	309,811	308,688	307,565	306,442	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,343	2,336	2,328	2,321	2,314	2,307	2,299	2,288	2,276	2,268	2,260	2,251	27,591
	b Debt Component (Line 6 x Debt Component x 1/12)		665	663	661	659	657	655	653	650	647	644	642	640	7,836
8	Investment Expenses														
	a Depreciation (E)		981	981	981	981	981	981	981	2,118	1,123	1,123	1,123	1,123	13,477
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		3,989	3,980	3,970	3,961	3,952	3,943	3,933	5,056	4,046	4,035	4,025	4,014	48,904
	a Recoverable Costs Allocated to Energy		3,989	3,980	3,970	3,961	3,952	3,943	3,933	5,056	4,046	4,035	4,025	4,014	48,904
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		3,843	3,846	3,837	3,836	3,831	3,819	3,813	4,895	3,920	3,907	3,888	3,869	47,304
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		3,843	3,846	3,837	3,836	3,831	3,819	3,813	4,895	3,920	3,907	3,888	3,869	47,304

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning and Ending Balances: Crist, $284,622 and Smith $106,497.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Crist 3.5% annually; Smith 3.3% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Stormwater Collection System
P.E. 1446
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	
3	Less: Accumulated Depreciation (C)	(1,212,625)	(1,218,421)	(1,224,217)	(1,230,013)	(1,235,809)	(1,241,605)	(1,247,401)	(1,253,197)	(1,273,841)	(1,281,493)	(1,289,145)	(1,296,797)	(1,304,449)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	1,569,975	1,564,179	1,558,383	1,552,587	1,546,791	1,540,995	1,535,199	1,529,403	1,508,759	1,501,107	1,493,455	1,485,803	1,478,151	
6	Average Net Investment		1,567,077	1,561,281	1,555,485	1,549,689	1,543,893	1,538,097	1,532,301	1,519,081	1,504,933	1,497,281	1,489,629	1,481,977	
7	Return on Average Net Investment														
a	Equity Component (Line 6 x Equity Component x 1/12) (D)		11,513	11,471	11,428	11,386	11,343	11,300	11,258	11,160	11,057	11,001	10,945	10,888	134,750
b	Debt Component (Line 6 x Debt Component x 1/12)		3,270	3,258	3,246	3,234	3,222	3,210	3,198	3,170	3,141	3,125	3,109	3,093	38,276
8	Investment Expenses														
a	Depreciation (E)		5,796	5,796	5,796	5,796	5,796	5,796	5,796	20,644	7,652	7,652	7,652	7,652	91,824
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		20,579	20,525	20,470	20,416	20,361	20,306	20,252	34,974	21,850	21,778	21,706	21,633	264,850
a	Recoverable Costs Allocated to Energy		1,583	1,579	1,575	1,570	1,566	1,562	1,558	2,690	1,681	1,675	1,670	1,664	20,373
b	Recoverable Costs Allocated to Demand		18,996	18,946	18,895	18,846	18,795	18,744	18,694	32,284	20,169	20,103	20,036	19,969	244,477
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		1,525	1,526	1,522	1,521	1,518	1,513	1,510	2,604	1,629	1,622	1,613	1,604	19,707
13	Retail Demand-Related Recoverable Costs (I)		18,316	18,268	18,219	18,172	18,122	18,073	18,025	31,129	19,447	19,384	19,319	19,254	235,728
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		19,841	19,794	19,741	19,693	19,640	19,586	19,535	33,733	21,076	21,006	20,932	20,858	255,435

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.3% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Waste Water Treatment Facility
P.E. 1466 & 1643
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	
3	Less: Accumulated Depreciation (C)	95,529	95,156	94,783	94,410	94,038	93,665	93,293	92,920	91,592	91,100	90,608	90,116	89,624	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	274,491	274,118	273,745	273,372	273,000	272,627	272,255	271,882	270,554	270,062	269,570	269,078	268,586	
6	Average Net Investment		274,305	273,932	273,559	273,186	272,814	272,441	272,069	271,218	270,308	269,816	269,324	268,832	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,015	2,013	2,010	2,007	2,004	2,002	1,999	1,993	1,986	1,982	1,979	1,975	23,965
	b Debt Component (Line 6 x Debt Component x 1/12)		572	572	571	570	569	569	568	566	564	563	562	561	6,807
8	Investment Expenses														
	a Depreciation (E)		373	373	373	372	373	372	373	1,328	492	492	492	492	5,905
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,960	2,958	2,954	2,949	2,946	2,943	2,940	3,887	3,042	3,037	3,033	3,028	36,677
	a Recoverable Costs Allocated to Energy		228	228	227	227	227	226	226	299	234	234	233	233	2,822
	b Recoverable Costs Allocated to Demand		2,732	2,730	2,727	2,722	2,719	2,717	2,714	3,588	2,808	2,803	2,800	2,795	33,855
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		220	220	219	220	220	219	219	289	227	227	225	225	2,730
13	Retail Demand-Related Recoverable Costs (I)		2,634	2,632	2,629	2,625	2,622	2,620	2,617	3,460	2,708	2,703	2,700	2,695	32,645
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,854	2,852	2,848	2,845	2,842	2,839	2,836	3,749	2,935	2,930	2,925	2,920	35,375

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.3% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Daniel Ash Management Project
P.E. 1535, 1555, & 1819
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
a	Expenditures/Additions		0	2,900	0	0	(136)	21,520	18,104	(883)	916	(2)	3	1,203	
b	Clearings to Plant		0	0	0	0	0	0	18,006	0	0	0	0	0	
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
d	Cost of Removal		166,369	(330,544)	63,614	(6,164)	4,891	7,359	6,357	868	62	18,231	5,342	(5,598)	
e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	16,192,223	16,192,223	16,192,223	16,192,223	16,192,223	16,192,223	16,192,223	16,210,229	16,210,229	16,210,229	16,210,229	16,210,229	16,210,229	
3	Less: Accumulated Depreciation (C)	(5,334,750)	(5,220,518)	(5,603,199)	(5,591,722)	(5,650,023)	(5,697,269)	(5,742,047)	(5,787,827)	(5,796,225)	(5,842,977)	(5,871,560)	(5,913,032)	(5,965,444)	
4	CWIP - Non Interest Bearing	(2,900)	(2,900)	0	0	0	(136)	21,384	21,482	20,599	21,515	21,513	21,516	22,719	
5	Net Investment (Lines 2 + 3 + 4)	10,854,573	10,968,805	10,589,024	10,600,501	10,542,200	10,494,818	10,471,560	10,443,884	10,434,603	10,388,767	10,360,182	10,318,713	10,267,504	
6	Average Net Investment		10,911,689	10,778,915	10,594,763	10,571,351	10,518,509	10,483,189	10,457,722	10,439,244	10,411,685	10,374,475	10,339,448	10,293,109	
7	Return on Average Net Investment														
a	Equity Component (Line 6 x Equity Component x 1/12) (D)		80,168	79,193	77,840	77,668	77,279	77,020	76,833	76,696	76,495	76,221	75,964	75,623	927,000
b	Debt Component (Line 6 x Debt Component x 1/12)		22,773	22,496	22,111	22,062	21,952	21,878	21,825	21,787	21,729	21,652	21,578	21,482	263,325
8	Investment Expenses														
a	Depreciation (E)		41,825	41,825	41,825	41,825	41,825	41,825	41,825	9,482	37,818	37,818	37,818	37,818	453,529
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		10,312	10,312	10,312	10,312	10,312	10,312	10,312	(216)	8,996	8,996	8,996	8,996	107,952
d	Property Taxes		30,219	30,219	30,219	30,219	30,219	30,219	30,219	30,219	30,219	30,219	30,219	30,219	362,628
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		185,297	184,045	182,307	182,086	181,587	181,254	181,014	137,968	175,257	174,906	174,575	174,138	2,114,434
a	Recoverable Costs Allocated to Energy		14,254	14,157	14,024	14,007	13,968	13,943	13,924	10,613	13,481	13,454	13,429	13,395	162,650
b	Recoverable Costs Allocated to Demand		171,043	169,888	168,283	168,079	167,619	167,311	167,090	127,355	161,776	161,452	161,146	160,743	1,951,784
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		13,732	13,681	13,555	13,566	13,539	13,506	13,499	10,274	13,061	13,028	12,972	12,910	157,323
13	Retail Demand-Related Recoverable Costs (I)		164,922	163,809	162,261	162,064	161,621	161,324	161,111	122,798	155,987	155,675	155,380	154,991	1,881,943
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		178,654	177,490	175,816	175,630	175,160	174,830	174,610	133,072	169,048	168,703	168,352	167,901	2,039,266

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 2.8% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Water Conservation
P.E. 1601, 1620, 1638
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	
3	Less: Accumulated Depreciation (C)	(21,920)	(22,199)	(22,478)	(22,757)	(23,036)	(23,315)	(23,593)	(23,872)	(24,867)	(25,236)	(25,605)	(25,974)	(26,343)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	112,214	111,935	111,656	111,377	111,098	110,819	110,541	110,262	109,267	108,898	108,529	108,160	107,791	
6	Average Net Investment		112,075	111,796	111,517	111,238	110,959	110,680	110,402	109,765	109,083	108,714	108,345	107,976	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		823	821	819	817	815	813	811	806	801	799	796	793	9,714
	b Debt Component (Line 6 x Debt Component x 1/12)		234	233	233	232	232	231	230	229	228	227	226	225	2,760
8	Investment Expenses														
	a Depreciation (E)		279	279	279	279	279	278	279	995	369	369	369	369	4,423
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,336	1,333	1,331	1,328	1,326	1,322	1,320	2,030	1,398	1,395	1,391	1,387	16,897
	a Recoverable Costs Allocated to Energy		103	103	102	102	102	102	102	156	108	107	107	107	1,301
	b Recoverable Costs Allocated to Demand		1,233	1,230	1,229	1,226	1,224	1,220	1,218	1,874	1,290	1,288	1,284	1,280	15,596
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		99	100	99	99	99	99	99	151	105	104	103	103	1,260
13	Retail Demand-Related Recoverable Costs (I)		1,189	1,186	1,185	1,182	1,180	1,176	1,174	1,807	1,244	1,242	1,238	1,234	15,037
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,288	1,286	1,284	1,281	1,279	1,275	1,273	1,958	1,349	1,346	1,341	1,337	16,297

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.3% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Docket No. 110007-EI
ECRC 2011 Final True-Up
Exhibit RWD-1, Page 24 of 39

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Underground Fuel Tank Replacement
P.E. 4397
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	0	0	0	0	0	0	0	0	0	0	0	0	0	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 6 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Applicable depreciation rate or rates.
(F) PE 4397 fully amortized.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Crist FDEP Agreement for Ozone Attainment
P.E. 1031, 1158, 1199, 1250, 1287
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	1,709	(1)	3	0	2,462	130,522	(5)	(130,516)	411,573	
	b Clearings to Plant		0	0	0	0	0	0	0	4,173	0	0	1	1,890	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	1,041	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	32,214	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	129,419,363	129,419,363	129,419,363	129,419,363	129,419,363	129,419,363	129,419,363	129,419,363	129,423,536	129,423,536	129,423,536	129,423,537	129,425,427	
3	Less: Accumulated Depreciation (C)	(15,465,827)	(15,841,447)	(16,217,067)	(16,623,860)	(16,999,480)	(17,375,100)	(17,750,720)	(18,126,340)	(18,792,336)	(19,204,253)	(19,616,170)	(20,028,087)	(20,440,004)	
4	CWIP - Non Interest Bearing	0	0	0	0	1,709	1,708	1,711	1,711	0	130,522	130,517	0	409,683	
5	Net Investment (Lines 2 + 3 + 4)	113,953,536	113,577,916	113,202,296	112,795,503	112,421,592	112,045,971	111,670,354	111,294,734	110,631,200	110,349,805	109,937,883	109,395,450	109,395,106	
6	Average Net Investment		113,765,726	113,390,106	112,998,900	112,608,548	112,233,782	111,858,163	111,482,544	110,962,967	110,490,503	110,143,844	109,666,667	109,395,278	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		835,837	833,077	830,203	827,335	824,582	821,822	819,061	815,244	811,773	809,226	805,722	803,726	9,837,608
	b Debt Component (Line 6 x Debt Component x 1/12)		237,429	236,645	235,829	235,014	234,232	233,448	232,664	231,580	230,594	229,870	228,874	228,308	2,794,487
8	Investment Expenses														
	a Depreciation (E)		344,648	344,648	344,648	344,648	344,648	344,648	344,648	603,102	376,955	376,955	376,955	376,955	4,523,458
	b Amortization (F)		2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	2,292	27,504
	c Dismantlement		28,680	28,680	28,680	28,680	28,680	28,680	28,680	60,602	32,670	32,670	32,670	32,670	392,042
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,448,886	1,445,342	1,441,652	1,437,969	1,434,434	1,430,890	1,427,345	1,712,820	1,454,284	1,451,013	1,446,513	1,443,951	17,575,099
	a Recoverable Costs Allocated to Energy		1,448,886	1,445,342	1,441,652	1,437,969	1,434,434	1,430,890	1,427,345	1,712,820	1,454,284	1,451,013	1,446,513	1,443,951	17,575,099
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		1,395,778	1,396,742	1,393,449	1,392,659	1,390,414	1,386,020	1,383,773	1,658,124	1,408,997	1,405,041	1,397,318	1,391,635	16,999,950
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,395,778	1,396,742	1,393,449	1,392,659	1,390,414	1,386,020	1,383,773	1,658,124	1,408,997	1,405,041	1,397,318	1,391,635	16,999,950

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.5% annually
(F) Portions of 1287 have 7-year amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: SPCC Compliance
P.E. 1272 & 1404
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	929,679	929,679	929,679	929,679	929,679	929,679	929,679	929,679	929,679	929,679	929,679	929,679	929,679	
3	Less: Accumulated Depreciation (C)	(89,577)	(92,050)	(94,523)	(96,996)	(99,470)	(101,944)	(104,418)	(106,892)	(111,258)	(113,968)	(116,678)	(119,388)	(122,098)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	840,102	837,629	835,156	832,683	830,209	827,735	825,261	822,787	818,421	815,711	813,001	810,291	807,581	
6	Average Net Investment		838,866	836,393	833,920	831,446	828,972	826,498	824,024	820,604	817,066	814,356	811,646	808,936	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		6,163	6,145	6,127	6,109	6,090	6,072	6,054	6,029	6,003	5,983	5,963	5,943	72,681
	b Debt Component (Line 6 x Debt Component x 1/12)		1,751	1,746	1,740	1,735	1,730	1,725	1,720	1,713	1,705	1,700	1,694	1,688	20,647
8	Investment Expenses														
	a Depreciation (E)		2,473	2,473	2,473	2,474	2,474	2,474	2,474	4,366	2,710	2,710	2,710	2,710	32,521
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		10,387	10,364	10,340	10,318	10,294	10,271	10,248	12,108	10,418	10,393	10,367	10,341	125,849
	a Recoverable Costs Allocated to Energy		799	797	795	794	792	790	788	931	801	799	797	795	9,679
	b Recoverable Costs Allocated to Demand		9,588	9,567	9,545	9,524	9,502	9,481	9,460	11,177	9,617	9,594	9,570	9,545	116,170
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		770	770	768	769	768	765	764	901	776	774	770	766	9,361
13	Retail Demand-Related Recoverable Costs (I)		9,245	9,225	9,203	9,183	9,162	9,142	9,121	10,777	9,273	9,251	9,228	9,203	112,013
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		10,015	9,995	9,971	9,952	9,930	9,907	9,885	11,678	10,049	10,025	9,998	9,969	121,374

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning Balances: Crist, $919,836; Smith $9,843. Ending Balances: Crist, $919,836; Smith $9,843.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Crist 3.5%; Smith 3.3% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Common FTIR Monitor
P.E. 1297
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	
3	Less: Accumulated Depreciation (C)	(11,919)	(12,087)	(12,255)	(12,423)	(12,591)	(12,759)	(12,927)	(13,095)	(13,388)	(13,571)	(13,754)	(13,937)	(14,120)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	50,951	50,783	50,615	50,447	50,279	50,111	49,943	49,775	49,482	49,299	49,116	48,933	48,750	
6	Average Net Investment		50,867	50,699	50,531	50,363	50,195	50,027	49,859	49,629	49,391	49,208	49,025	48,842	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		374	372	371	370	369	368	366	365	363	362	360	359	4,399
	b Debt Component (Line 6 x Debt Component x 1/12)		106	106	105	105	105	104	104	104	103	103	102	102	1,249
8	Investment Expenses														
	a Depreciation (E)		168	168	168	168	168	168	168	293	183	183	183	183	2,201
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		648	646	644	643	642	640	638	762	649	648	645	644	7,849
	a Recoverable Costs Allocated to Energy		648	646	644	643	642	640	638	762	649	648	645	644	7,849
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		624	624	622	623	622	620	619	738	629	627	623	621	7,592
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		624	624	622	623	622	620	619	738	629	627	623	621	7,592

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.5% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Docket No. 110007-EI
ECRC 2011 Final True-Up
Exhibit RWD-1, Page 28 of 39

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Precipitator Upgrades for CAM Compliance
P.E. 1175, 1191, 1305, 1461, 1462
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	
3	Less: Accumulated Depreciation (C)	(2,293,417)	(2,363,927)	(2,434,437)	(2,504,947)	(2,575,457)	(2,645,967)	(2,716,477)	(2,786,987)	(2,969,265)	(3,053,746)	(3,138,227)	(3,222,708)	(3,307,189)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	27,546,261	27,475,751	27,405,241	27,334,731	27,264,221	27,193,711	27,123,201	27,052,691	26,870,413	26,785,932	26,701,451	26,616,970	26,532,489	
6	Average Net Investment		27,511,006	27,440,496	27,369,986	27,299,476	27,228,966	27,158,456	27,087,946	26,961,552	26,828,173	26,743,692	26,659,211	26,574,730	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		202,123	201,605	201,087	200,569	200,051	199,533	199,015	198,086	197,106	196,486	195,865	195,244	2,386,770
	b Debt Component (Line 6 x Debt Component x 1/12)		57,415	57,268	57,121	56,974	56,827	56,680	56,533	56,269	55,990	55,814	55,638	55,461	677,990
8	Investment Expenses														
	a Depreciation (E)		70,510	70,510	70,510	70,510	70,510	70,510	70,510	182,278	84,481	84,481	84,481	84,481	1,013,772
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		330,048	329,383	328,718	328,053	327,388	326,723	326,058	436,633	337,577	336,781	335,984	335,186	4,078,532
	a Recoverable Costs Allocated to Energy		330,048	329,383	328,718	328,053	327,388	326,723	326,058	436,633	337,577	336,781	335,984	335,186	4,078,532
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		317,950	318,307	317,727	317,716	317,341	316,478	316,105	422,690	327,065	326,111	324,557	323,042	3,945,089
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		317,950	318,307	317,727	317,716	317,341	316,478	316,105	422,690	327,065	326,111	324,557	323,042	3,945,089

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning Balances: Crist $13,997,696; Smith $15,715,201; Scholz $126,781. Ending Balances: Crist, $13,997,696; Smith $15,715,201; Scholz $126,781.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Crist 3.5%; Smith 3.3%; Scholz 4.1% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Plant Groundwater Investigation
P.E. 1218 & 1361
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	0	0	0	0	0	0	0	0	0	0	0	0	0	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 6 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Beginning Balances: Crist $0; Scholz $0. Ending Balances: Crist $0; Scholz $0.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Crist 3.5% annually; Scholz 4.1% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Docket No. 110007-EI
ECRC 2011 Final True-Up
Exhibit RWD-1, Page 30 of 39

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Plant Crist Water Conservation Project
P.E.'s 1227 & 1298
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		8,597,865	480,168	1,156,883	710,340	5,986,010	614,232	337,306	343,906	508,841	101,546	152,811	(41,919)	
	b Clearings to Plant		8,597,865	480,168	1,156,883	710,340	5,986,010	614,232	337,306	343,906	508,841	101,546	152,811	(41,919)	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	93,736	8,691,601	9,171,769	10,328,652	11,038,992	17,025,002	17,639,234	17,976,540	18,320,446	18,829,287	18,930,833	19,083,644	19,041,725	
3	Less: Accumulated Depreciation (C)	(9,148)	(9,398)	(32,579)	(57,040)	(84,587)	(114,028)	(159,434)	(206,478)	(277,413)	(330,854)	(385,779)	(441,000)	(496,667)	
4	CWIP - Non Interest Bearing (J)	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	84,588	8,682,203	9,139,190	10,271,612	10,954,405	16,910,974	17,479,800	17,770,062	18,043,033	18,498,433	18,545,054	18,642,644	18,545,058	
6	Average Net Investment		4,383,396	8,910,697	9,705,401	10,613,009	13,932,690	17,195,387	17,624,931	17,906,548	18,270,733	18,521,744	18,593,849	18,593,851	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		32,205	65,467	71,306	77,974	102,363	126,335	129,490	131,560	134,234	136,079	136,609	136,609	1,280,231
	b Debt Component (Line 6 x Debt Component x 1/12)		9,148	18,597	20,255	22,149	29,078	35,887	36,783	37,371	38,131	38,655	38,805	38,805	363,664
8	Investment Expenses														
	a Depreciation (E)		250	23,181	24,461	27,547	29,441	45,406	47,044	70,935	53,441	54,925	55,221	55,667	487,519
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		41,603	107,245	116,022	127,670	160,882	207,628	213,317	239,866	225,806	229,659	230,635	231,081	2,131,414
	a Recoverable Costs Allocated to Energy		3,200	8,250	8,925	9,821	12,376	15,971	16,409	18,451	17,370	17,666	17,741	17,775	163,955
	b Recoverable Costs Allocated to Demand		38,403	98,995	107,097	117,849	148,506	191,657	196,908	221,415	208,436	211,993	212,894	213,306	1,967,459
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		3,083	7,973	8,627	9,512	11,996	15,470	15,908	17,862	16,829	17,106	17,138	17,131	158,635
13	Retail Demand-Related Recoverable Costs (I)		37,029	95,453	103,265	113,632	143,192	184,799	189,862	213,492	200,977	204,407	205,276	205,673	1,897,057
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		40,112	103,426	111,892	123,144	155,188	200,269	205,770	231,354	217,806	221,513	222,414	222,804	2,055,692

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.5% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11
(J) Revised to exclude $73,956 that was incorrectly included in CWIP in December 2008 for PE 1298.

)   )   )

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: Plant NPDES Permit Compliance Projects
P.E. 1204 & 1299
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	27,609	12,108	8,442	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	48,159	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	5,969,277	5,969,277	5,969,277	5,969,277	5,969,277	5,969,277	5,969,277	5,969,277	5,969,277	5,969,277	5,969,277	5,969,277	6,017,436	
3	Less: Accumulated Depreciation (C)	(689,409)	(705,327)	(721,245)	(737,163)	(753,083)	(769,003)	(784,923)	(800,843)	(828,702)	(846,114)	(863,526)	(880,938)	(898,350)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	27,609	39,717	0	
5	Net Investment (Lines 2 + 3 + 4)	5,279,868	5,263,950	5,248,032	5,232,114	5,216,194	5,200,274	5,184,354	5,168,434	5,140,575	5,123,163	5,133,360	5,128,056	5,119,086	
6	Average Net Investment		5,271,909	5,255,991	5,240,073	5,224,154	5,208,234	5,192,314	5,176,394	5,154,505	5,131,869	5,128,262	5,130,708	5,123,571	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		38,733	38,616	38,499	38,382	38,265	38,148	38,031	37,869	37,704	37,677	37,695	37,643	457,262
	b Debt Component (Line 6 x Debt Component x 1/12)		11,002	10,969	10,936	10,903	10,870	10,836	10,803	10,757	10,710	10,703	10,708	10,693	129,890
8	Investment Expenses														
	a Depreciation (E)		15,918	15,918	15,918	15,920	15,920	15,920	15,920	27,859	17,412	17,412	17,412	17,412	208,941
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		65,653	65,503	65,353	65,205	65,055	64,904	64,754	76,485	65,826	65,792	65,815	65,748	796,093
	a Recoverable Costs Allocated to Energy		5,050	5,039	5,027	5,016	5,004	4,993	4,981	5,883	5,064	5,061	5,063	5,058	61,240
	b Recoverable Costs Allocated to Demand		60,603	60,464	60,326	60,189	60,051	59,911	59,773	70,602	60,762	60,731	60,752	60,690	734,853
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		4,865	4,870	4,859	4,858	4,850	4,836	4,829	5,695	4,906	4,901	4,891	4,875	59,235
13	Retail Demand-Related Recoverable Costs (I)		58,434	58,300	58,167	58,035	57,902	57,767	57,634	68,076	58,588	58,558	58,578	58,518	708,557
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		63,299	63,170	63,026	62,893	62,752	62,603	62,463	73,771	63,494	63,459	63,469	63,393	767,792

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable.
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.5% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR/CAVR Compliance
P.E.s 1034, 1035, 1036, 1037, 1222, 1233, 1279, 1362, 1468, 1469, 1512, 1513, 1646, 1647, 1684, 1810, 1824, & 1826
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		22,501,033	1,676,950	2,011,932	1,494,462	(213,038)	1,739,586	1,231,731	1,311,881	(289,931)	2,863,280	(2,539,585)	5,012,538	
	b Clearings to Plant		22,448,670	1,270,773	1,724,975	702,342	2,571,991	1,730,141	1,184,039	1,326,968	(454,527)	3,131,847	(2,611,539)	5,001,991	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	7,150	33,885	4,626	(3,798)	(23,999)	(1,526)	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	589,541,253	611,989,923	613,260,696	614,985,671	615,688,013	618,260,004	619,990,145	621,174,182	622,501,150	622,046,623	625,178,470	622,566,931	627,568,922	
3	Less: Accumulated Depreciation (C)	(4,073,338)	(5,641,501)	(7,269,533)	(8,900,954)	(10,536,975)	(12,174,869)	(13,819,383)	(15,461,349)	(20,839,524)	(22,962,022)	(25,091,577)	(27,249,607)	(29,377,565)	
4	CWIP - Non Interest Bearing	1,510,794	1,563,157	1,969,334	2,256,291	3,048,411	263,382	272,827	320,519.00	305,432	470,028	201,461	273,415	283,962	
5	Net Investment (Lines 2 + 3 + 4)	586,978,709	607,911,579	607,960,497	608,341,008	608,199,449	606,348,517	606,443,589	606,033,352	601,967,058	599,554,629	600,288,354	595,590,739	598,475,319	
6	Average Net Investment		597,445,144	607,936,038	608,150,753	608,270,229	607,273,983	606,396,053	606,238,471	604,000,205	600,760,844	599,921,492	597,939,547	597,033,029	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		4,389,429	4,466,506	4,468,084	4,468,961	4,461,642	4,455,192	4,454,033	4,437,589	4,413,789	4,407,623	4,393,062	4,386,401	53,202,311
	b Debt Component (Line 6 x Debt Component x 1/12)		1,246,868	1,268,763	1,269,211	1,269,460	1,267,381	1,265,549	1,265,220	1,260,548	1,253,788	1,252,036	1,247,900	1,246,008	15,112,732
8	Investment Expenses														
	a Depreciation (E)		1,559,732	1,619,601	1,622,990	1,627,590	1,629,463	1,636,083	1,640,685	2,884,453	1,803,796	1,802,429	1,810,703	1,803,104	21,440,629
	b Amortization (F)		8,431	8,431	8,431	8,431	8,431	8,431	8,431	8,431	8,431	8,431	8,431	8,431	101,172
	c Dismantlement		0	0	0	0	0	0	0	2,519,176	314,897	314,897	314,897	314,897	3,778,764
	d Property Taxes		9,898	9,898	9,898	9,898	9,898	9,898	9,898	9,898	9,898	9,898	9,898	9,898	118,776
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		7,214,358	7,373,199	7,378,614	7,384,340	7,376,815	7,375,153	7,378,267	11,120,095	7,804,599	7,795,314	7,784,891	7,768,739	93,754,384
	a Recoverable Costs Allocated to Energy		7,214,358	7,373,199	7,378,614	7,384,340	7,376,815	7,375,153	7,378,267	11,120,095	7,804,599	7,795,314	7,784,891	7,768,739	93,754,384
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		6,949,918	7,125,274	7,131,904	7,151,663	7,150,437	7,143,881	7,153,034	10,764,993	7,561,562	7,548,339	7,520,133	7,487,268	90,688,406
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		6,949,918	7,125,274	7,131,904	7,151,663	7,150,437	7,143,881	7,153,034	10,764,993	7,561,562	7,548,339	7,520,133	7,487,268	90,688,406

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Beginning Balances: Crist $572,297,304; Smith $12,930,098; Daniel $3,669,630; Scholz $644,221. Ending Balances: Crist $607,220,634; Smith $12,931,386; Daniel $6,772,682; Scholz $644,221.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Crist: 3.5%, Plant Smith Steam 3.3%, Smith CT 3.6%, Daniel 2.8%, Scholz 4.1%. Portion of PE 1222 is transmission 2.3%, 3.6%, and 2.5%
(F) Portion of PE 1222 applicable 7 year amortization period beginning in 2008.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11
(J) Project #1222 qualifies for AFUDC treatment. As portions of the project are moved to P-I-S, they are included in the ECRC.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Capital Investments, Depreciation and Taxes
For Project: General Water Quality
P.E.1280
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	
3	Less: Accumulated Depreciation (C)	(9,462)	(9,996)	(10,530)	(11,064)	(11,598)	(12,132)	(12,666)	(13,200)	(13,734)	(14,268)	(14,802)	(15,336)	(15,870)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	22,559	22,025	21,491	20,957	20,423	19,889	19,355	18,821	18,287	17,753	17,219	16,685	16,151	
6	Average Net Investment		22,292	21,758	21,224	20,690	20,156	19,622	19,088	18,554	18,020	17,486	16,952	16,418	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		164	160	156	152	148	144	140	136	132	128	125	121	1,706
	b Debt Component (Line 6 x Debt Component x 1/12)		47	45	44	43	42	41	40	39	38	36	35	34	484
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		534	534	534	534	534	534	534	534	534	534	534	534	6,408
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		745	739	734	729	724	719	714	709	704	698	694	689	8,598
	a Recoverable Costs Allocated to Energy		57	57	56	56	56	55	55	55	54	54	53	53	661
	b Recoverable Costs Allocated to Demand		688	682	678	673	668	664	659	654	650	644	641	636	7,937
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (H)		55	55	54	54	54	53	53	53	52	52	51	51	637
13	Retail Demand-Related Recoverable Costs (I)		663	658	654	649	644	640	635	631	627	621	618	613	7,653
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		718	713	708	703	698	693	688	684	679	673	669	664	8,290

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Applicable depreciation rate or rates.
(F) 5 year amortization beginning 2008.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Working Capital, Mercury Allowance Expenses
For Project: Mercury Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	0	0	0	0	0	0	0	0	0	0	0	0	0	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	Average Net Working Capital Balance		0	0	0	0	0	0	0	0	0	0	0	0	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 4 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
6	Total Return Component (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
7	Expenses														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c SO2 Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Net Expenses (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 6 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (B)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(A) Equity Component has been grossed up for taxes. Based on ROE of 12% and weighted income tax rate of 38.575%
(B) Line 9a x Line 10 x 1.0007 line loss multiplier
(C) Line 9b x Line 11
(D) Line 6 is reported on Schedule 6E and 7E
(E) Line 8 is reported on Schedule 4E and 5E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Working Capital, Annual NOx Expenses
For Project: Annual Nox Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Purchases/Transfers		495,000	837,500	0	0	1,590,000	2,165,000	0	0	0	0	0	1,425,000	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	6,323,555	4,729,142	5,251,782	4,668,927	4,321,424	5,509,670	7,051,777	6,172,487	5,274,738	4,554,180	4,087,411	3,629,004	4,533,753	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	6,323,555	4,729,142	5,251,782	4,668,927	4,321,424	5,509,670	7,051,777	6,172,487	5,274,738	4,554,180	4,087,411	3,629,004	4,533,753	
4	Average Net Working Capital Balance		5,526,349	4,990,462	4,960,355	4,495,176	4,915,547	6,280,724	6,612,132	5,723,613	4,914,459	4,320,796	3,858,208	4,081,379	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		40,602	36,665	36,444	33,026	36,115	46,144	48,579	42,051	36,107	31,745	28,346	29,986	445,810
	b Debt Component (Line 4 x Debt Component x 1/12)		11,533	10,415	10,352	9,381	10,259	13,108	13,800	11,945	10,256	9,018	8,052	8,518	126,637
6	Total Return Component (D)		52,135	47,080	46,796	42,407	46,374	59,252	62,379	53,996	46,363	40,763	36,398	38,504	572,447
7	Expenses														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Annual Nox Allowance Expense		2,089,413	314,860	582,855	347,503	401,754	622,893	879,290	897,749	720,558	466,769	458,407	520,251	8,302,302
8	Net Expenses (E)		2,089,413	314,860	582,855	347,503	401,754	622,893	879,290	897,749	720,558	466,769	458,407	520,251	8,302,302
9	Total System Recoverable Expenses (Lines 6 + 8)		2,141,548	361,940	629,651	389,910	448,128	682,145	941,669	951,745	766,921	507,532	494,805	558,755	8,874,749
	a Recoverable Costs Allocated to Energy		2,141,548	361,940	629,651	389,910	448,128	682,145	941,669	951,745	766,921	507,532	494,805	558,755	8,874,749
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (B)		2,063,050	349,770	608,598	377,624	434,376	660,754	912,923	921,353	743,039	491,452	477,977	538,511	8,579,427
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,063,050	349,770	608,598	377,624	434,376	660,754	912,923	921,353	743,039	491,452	477,977	538,511	8,579,427

Notes:
(A) Equity Component has been grossed up for taxes. Based on ROE of 12% and weighted income tax rate of 38.575%
(B) Line 9a x Line 10 x 1.0007 line loss multiplier
(C) Line 9b x Line 11
(D) Line 6 is reported on Schedule 6E and 7E
(E) Line 8 is reported on Schedule 4E and 5E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Working Capital, Seasonal NOx Expenses
For Project: Seasonal Nox Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	5,250	3,150	4,600	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	214,495	214,495	214,495	214,495	214,495	175,932	132,313	83,135	35,892	0	0	4,600	4,600	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	214,495	214,495	214,495	214,495	214,495	175,932	132,313	83,135	35,892	0	0	4,600	4,600	
4	Average Net Working Capital Balance		214,495	214,495	214,495	214,495	195,214	154,123	107,724	59,514	17,946	0	2,300	4,600	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		1,576	1,576	1,576	1,576	1,434	1,132	791	437	132	0	17	34	10,281
	b Debt Component (Line 4 x Debt Component x 1/12)		448	448	448	448	407	322	225	124	37	0	5	10	2,922
6	Total Return Component (D)		2,024	2,024	2,024	2,024	1,841	1,454	1,016	561	169	0	22	44	13,203
7	Expenses														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Seasonal NOx Allowance Expense		0	0	0	0	38,563	43,619	49,177	47,243	41,142	3,150	0	0	222,895
8	Net Expenses (E)		0	0	0	0	38,563	43,619	49,177	47,243	41,142	3,150	0	0	222,895
9	Total System Recoverable Expenses (Lines 6 + 8)		2,024	2,024	2,024	2,024	40,404	45,073	50,193	47,804	41,311	3,150	22	44	236,098
	a Recoverable Costs Allocated to Energy		2,024	2,024	2,024	2,024	40,404	45,073	50,193	47,804	41,311	3,150	22	44	236,098
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (B)		1,950	1,956	1,956	1,960	39,164	43,660	48,661	46,277	40,025	3,050	21	42	228,722
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,950	1,956	1,956	1,960	39,164	43,660	48,661	46,277	40,025	3,050	21	42	228,722

Notes:
(A) Equity Component has been grossed up for taxes. Based on ROE of 12% and weighted income tax rate of 38.575%
(B) Line 9a x Line 10 x 1.0007 line loss multiplier
(C) Line 9b x Line 11
(D) Line 6 is reported on Schedule 6E and 7E
(E) Line 8 is reported on Schedule 4E and 5E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010

Return on Working Capital, SO2 Expenses
For Project: SO2 Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Actual July	Actual August	Actual September	Actual October	Actual November	Actual December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	30,587	0	4,744	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	12,399,623	11,720,378	11,550,605	11,171,176	11,308,542	11,095,414	10,883,443	10,635,506	10,379,642	10,154,983	10,017,360	9,885,358	9,765,388	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	(985,310)	(978,916)	(972,522)	(966,128)	(986,922)	(977,129)	(971,665)	(961,457)	(951,249)	(941,041)	(930,833)	(920,625)	(910,417)	
3	Total Working Capital Balance	11,414,313	10,741,462	10,578,083	10,205,048	10,321,620	10,118,285	9,911,778	9,674,049	9,428,393	9,213,942	9,086,527	8,964,733	8,854,971	
4	Average Net Working Capital Balance		11,077,888	10,659,773	10,391,566	10,263,334	10,219,953	10,015,032	9,792,914	9,551,221	9,321,168	9,150,235	9,025,630	8,909,852	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		81,389	78,317	76,347	75,405	75,086	73,580	71,949	70,173	68,483	67,227	66,311	65,461	869,728
	b Debt Component (Line 4 x Debt Component x 1/12)		23,120	22,247	21,687	21,420	21,329	20,901	20,438	19,933	19,453	19,097	18,836	18,595	247,056
6	Total Return Component (D)		104,509	100,564	98,034	96,825	96,415	94,481	92,387	90,106	87,936	86,324	85,147	84,056	1,116,784
7	Expenses														
	a Gains		(6,394)	(6,394)	(6,394)	(9,793)	(9,793)	(10,208)	(10,208)	(10,208)	(10,208)	(10,208)	(10,208)	(10,208)	(110,224)
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c SO2 Allowance Expense		679,245	169,773	379,429	(137,366)	213,128	211,971	247,937	255,864	224,659	137,623	132,002	119,970	2,634,235
8	Net Expenses (E)		672,851	163,379	373,035	(147,159)	203,335	201,763	237,729	245,656	214,451	127,415	121,794	109,762	2,524,011
9	Total System Recoverable Expenses (Lines 6 + 8)		777,360	263,943	471,069	(50,334)	299,750	296,244	330,116	335,762	302,387	213,739	206,941	193,818	3,640,795
	a Recoverable Costs Allocated to Energy		777,360	263,943	471,069	(50,334)	299,750	296,244	330,116	335,762	302,387	213,739	206,941	193,818	3,640,795
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9626715	0.9656988	0.9658880	0.9678130	0.9686342	0.9679641	0.9687953	0.9673895	0.9681820	0.9676402	0.9653151	0.9630946	
11	Demand Jurisdictional Factor		0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	0.9642160	
12	Retail Energy-Related Recoverable Costs (B)		748,866	255,068	455,318	(48,748)	290,551	286,954	320,039	325,040	292,971	206,967	199,903	186,796	3,519,725
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		748,866	255,068	455,318	(48,748)	290,551	286,954	320,039	325,040	292,971	206,967	199,903	186,796	3,519,725

Notes:
(A) Equity Component has been grossed up for taxes. Based on ROE of 12% and weighted income tax rate of 38.575%
(B) Line 9a x Line 10 x 1.0007 line loss multiplier
(C) Line 9b x Line 11
(D) Line 6 is reported on Schedule 6E and 7E
(E) Line 8 is reported on Schedule 4E and 5E

Schedule 9A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Final True-Up Amount
January 2010 - December 2010
FPSC Capital Structure and Cost Rates

Line	Capital Component	(1) Jurisdictional Rate Base Test Year ($000's)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %	(5) Revenue Requirement Rate %	(6) Monthly Revenue Requirement Rate %
1	Bonds	423,185	35.2733	6.44	2.2716	2.2716	
2	Short-Term Debt	33,714	2.8101	4.61	0.1295	0.1295	
3	Preferred Stock	98,680	8.2252	4.93	0.4055	0.6602	
4	Common Stock	492,186	41.0247	12.00	4.9230	8.0147	
5	Customer Deposits	13,249	1.1043	5.98	0.0660	0.0660	
6	Deferred Taxes	122,133	10.1801				
7	Investment Tax Credit	16,584	1.3823	8.99	0.1243	0.1790	
8	Total	1,199,731	100.0000		7.9199	11.3210	0.9434
	ITC Component:						
9	Debt	423,185	41.7321	6.44	2.6875	0.0371	
10	Equity-Preferred	98,680	9.7313	4.93	0.4798	0.0108	
11	-Common	492,186	48.5366	12.00	5.8244	0.1311	
12		1,014,051	100.0000		8.9917	0.1790	
	Breakdown of Revenue Requirement Rate of Return between Debt and Equity:						
13	Total Debt Component (Lines 1, 2, 5, and 9)					2.5042	0.2087
14	Total Equity Component (Lines 3, 4, 10, and 11)					8.8168	0.7347
15	Total Revenue Requirement Rate of Return					11.3210	0.9434

Column:
(1) Capital Structure Approved by FPSC on June 10, 2002 in Docket No. 010949-EI
(2) Column (1) / Total Column (1)
(3) Cost Rates Approved by FPSC on June 10, 2002 in Docket No. 010949-EI
(4) Column (2) x Column (3)
(5) For equity components: Column (4) / (1-.38575); 38.575% = effective income tax rate
For debt components: Column (4)
(6) Column (5) / 12

Schedule 1E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Line		Period Amount ($)
1	Over/(Under) Recovery for the current period (Schedule 2E, Line 5)	14,358,948
2	Interest Provision (Schedule 2E, Line 6)	21,565
3	Current Period True-Up Amount to be refunded/(recovered) in the projection period January 2011 - December 2011 (Lines 1 + 2)	14,380,513

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI EXHIBIT 36
PARTY GULF POWER COMPANY (DIRECT)
DESCRIPTION R. W. DODD (RWD-2)
DATE 11/01/11

Schedule 2E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Current Period True-Up Amount
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	ECRC Revenues (net of Revenue Taxes)	12,003,577	10,570,628	9,823,237	11,264,837	12,276,522	15,594,951	15,917,514	15,796,865	13,886,276	12,565,168	10,871,186	11,993,264	152,564,026
2	True-Up Provision (Order No. PSC-10-0683-FOF-EI)	792,501	792,501	792,501	792,501	792,501	792,501	792,501	792,501	792,501	792,501	792,501	792,501	9,510,006
3	**ECRC Revenues Applicable to Period (Lines 1 + 2)**	12,796,077	11,363,129	10,615,738	12,057,338	13,069,023	16,387,451	16,710,015	16,589,366	14,678,777	13,357,669	11,663,687	12,785,765	162,074,032
4	Jurisdictional ECRC Costs													
	a O & M Activities (Schedule 5E, Line 9)	1,198,954	2,139,055	1,446,487	1,610,954	1,651,024	2,269,513	2,237,729	2,461,628	2,198,044	2,072,312	2,209,440	3,063,276	24,558,416
	b Capital Investment Projects (Schedule 7E, Line 9)	10,292,615	10,324,148	10,304,039	10,306,525	10,242,621	10,241,708	10,236,886	10,270,030	10,246,066	10,240,138	10,226,239	10,225,653	123,156,668
	c **Total Jurisdictional ECRC Costs**	11,491,569	12,463,203	11,750,526	11,917,479	11,893,645	12,511,221	12,474,615	12,731,658	12,444,110	12,312,450	12,435,679	13,288,929	147,715,084
5	**Over/(Under) Recovery (Line 3 - Line 4c)**	1,304,508	(1,100,074)	(1,134,788)	139,859	1,175,378	3,876,230	4,235,400	3,857,708	2,234,667	1,045,219	(771,993)	(503,165)	14,358,948
6	Interest Provision (Schedule 3E, Line 10)	2,210	2,067	1,510	1,099	965	1,110	1,544	1,977	2,277	2,390	2,303	2,113	21,565
7	Beginning Balance True-Up & Interest Provision													
	a Actual Total for True-Up Period 2010	626,546	1,140,764	(749,744)	(2,675,522)	(3,327,065)	(2,943,223)	141,617	3,586,060	6,653,244	8,097,687	8,352,795	6,790,605	626,546
	b Final True-Up from January 2009 - December 2009 (Order No. PSC-10-0683-FOF-EI)	9,744,785	9,744,785	9,744,785	9,744,785	9,744,785	9,744,785	9,744,785	9,744,785	9,744,785	9,744,785	9,744,785	9,744,785	9,744,785
8	True-Up Collected/(Refunded) (see Line 2)	(792,501)	(792,501)	(792,501)	(792,501)	(792,501)	(792,501)	(792,501)	(792,501)	(792,501)	(792,501)	(792,501)	(792,501)	(9,510,006)
	Annual NOx Allowance Expense													
9	Adjustments													
10	End of Period Total True-Up (Lines 5 + 6 + 7a + 7b + 8)	10,885,549	8,995,041	7,069,263	6,417,720	6,801,563	9,886,402	13,330,845	16,398,029	17,842,472	18,097,580	16,535,390	15,241,838	15,241,838

Docket No. 110007-EI
ECRC 2011 Est/Act True-UP
Exhibit RWD-2, Page 2 of 39

Schedule 3E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Interest Provision
(in Dollars)

Line	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1 Beg. True-Up Amount (Schedule 2E, Lines 7a + 7b)	10,371,331	10,885,549	8,995,041	7,069,263	6,417,720	6,801,563	9,886,402	13,330,845	16,398,029	17,842,472	18,097,580	16,535,390	
2 Ending True-Up Amount Before Interest (Line 1 + Schedule 2E, Lines 5 + 8)	10,883,339	8,992,974	7,067,753	6,416,621	6,800,598	9,885,292	13,329,301	16,396,052	17,840,195	18,095,190	16,533,087	15,239,725	
3 Total of Beginning & Ending True-up (Lines 1 + 2)	21,254,670	19,878,523	16,062,794	13,485,884	13,218,318	16,686,855	23,215,703	29,726,897	34,238,224	35,937,662	34,630,667	31,775,115	
4 Average True-Up Amount (Line 3 x 1/2)	10,627,335	9,939,262	8,031,397	6,742,942	6,609,159	8,343,427	11,607,852	14,863,449	17,119,112	17,968,831	17,315,334	15,887,558	
5 Interest Rate (First Day of Reporting Business Month)	0.002500	0.002500	0.002500	0.002000	0.001900	0.001600	0.001600	0.001600	0.001600	0.001600	0.001600	0.001600	
6 Interest Rate (First Day of Subsequent Business Month)	0.002500	0.002500	0.002000	0.001900	0.001600	0.001600	0.001600	0.001600	0.001600	0.001600	0.001600	0.001600	
7 Total of Beginning and Ending Interest Rates (Line 5 + Line 6)	0.005000	0.005000	0.004500	0.003900	0.003500	0.003200	0.003200	0.003200	0.003200	0.003200	0.003200	0.003200	
8 Average Interest Rate (Line 7 x 1/2)	0.002500	0.002500	0.002250	0.001950	0.001750	0.001600	0.001600	0.001600	0.001600	0.001600	0.001600	0.001600	
9 Monthly Average Interest Rate (Line 8 x 1/12)	0.000208	0.000208	0.000188	0.000163	0.000146	0.000133	0.000133	0.000133	0.000133	0.000133	0.000133	0.000133	
10 Interest Provision for the Month (Line 4 x Line 9)	2,210	2,067	1,510	1,099	965	1,110	1,544	1,977	2,277	2,390	2,303	2,113	21,565

Schedule 4E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Variance Report of O & M Activities
(in Dollars)

Line		(1) Estimated/ Actual	(2) Original Projection	(3) Variance Amount	(4) Variance Percent
1	Description of O & M Activities				
	.1 Sulfur	0	0	0	0.0 %
	.2 Air Emission Fees	769,854	812,434	(42,580)	(5.2) %
	.3 Title V	118,191	121,032	(2,841)	(2.3) %
	.4 Asbestos Fees	2,200	1,200	1,000	83.3 %
	.5 Emission Monitoring	569,277	614,066	(44,789)	(7.3) %
	.6 General Water Quality	676,093	515,765	160,328	31.1 %
	.7 Groundwater Contamination Investigation	1,816,702	1,804,355	12,347	0.7 %
	.8 State NPDES Administration	36,511	34,500	2,011	5.8 %
	.9 Lead and Copper Rule	12,208	16,000	(3,792)	(23.7) %
	.10 Env Auditing/Assessment	7,014	17,000	(9,986)	(58.7) %
	.11 General Solid & Hazardous Waste	767,470	416,237	351,233	84.4 %
	.12 Above Ground Storage Tanks	109,803	92,366	17,437	18.9 %
	.13 Low Nox	0	0	0	0.0 %
	.14 Ash Pond Diversion Curtains	1,104	0	1,104	100.0 %
	.15 Mercury Emissions	0	0	0	0.0 %
	.16 Sodium Injection	66,564	229,200	(162,636)	(71.0) %
	.17 Gulf Coast Ozone Study	0	0	0	0.0 %
	.18 SPCC Substation Project	0	0	0	0.0 %
	.19 FDEP NOx Reduction Agreement	1,937,051	3,017,621	(1,080,570)	(35.8) %
	.20 CAIR/CAMR/CAVR Compliance Program	13,836,032	22,429,880	(8,593,848)	(38.3) %
	.21 MACT ICR	0	0	0	100.0 %
	.22 Crist Water Conservation	144,944	0	144,944	100.0 %
	.23 Mercury Allowances	0	0	0	0.0 %
	.24 Annual NOx Allowances	3,265,584	3,237,029	28,555	0.9 %
	.25 Seasonal NOx Allowances	15,853	120,015	(104,162)	(86.8) %
	.26 SO2 Allowances	1,239,073	1,934,214	(695,141)	(35.9) %
2	Total O & M Activities	25,391,528	35,412,914	(10,021,386)	(28.3) %
3	Recoverable Costs Allocated to Energy	21,818,583	32,515,491	(10,696,908)	(32.9) %
4	Recoverable Costs Allocated to Demand	3,572,945	2,897,423	675,522	23.3 %

Notes:

Column (1) is the End of Period Totals on Schedule 5E
Column (2) is the approved Projected amount in accordance with FPSC Order No. PSC-10-0683-FOF-EI
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

O & M Activities
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period 12-Month	Method of Classification Demand	Method of Classification Energy
1	Description of O & M Activities															
.1	Sulfur	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
.2	Air Emission Fees	-	645,480	-	-	-	-	-	-	-	-	124,374	-	769,854	0	769,854
.3	Title V	8,437	7,797	8,446	8,607	10,395	7,995	13,533	9,657	10,217	10,357	8,357	14,393	118,191	0	118,191
.4	Asbestos Fees	-	1,000	-	-	-	-	-	-	-	1,200	-	-	2,200	2,200	0
.5	Emission Monitoring	37,033	38,531	40,031	38,769	34,105	66,863	56,518	47,719	46,719	54,719	50,719	57,551	569,277	0	569,277
.6	General Water Quality	32,837	22,795	40,146	47,941	68,620	54,229	101,885	70,063	58,100	67,809	65,083	46,585	676,093	676,093	0
.7	Groundwater Contamination Investigation	56,636	108,985	79,477	90,047	188,537	260,444	120,135	261,000	253,300	174,500	117,500	106,141	1,816,702	1,816,702	0
.8	State NPDES Administration	-	-	-	555	1,456	40,054	(40,054)	-	-	-	-	34,500	36,511	36,511	0
.9	Lead and Copper Rule	325	-	-	3,883	-	-	4,000	-	-	4,000	-	-	12,208	12,208	0
.10	Env Auditing/Assessment	14	-	-	-	-	-	-	-	-	3,500	3,500	-	7,014	7,014	0
.11	General Solid & Hazardous Waste	139,352	46,936	196,641	119,360	(47,476)	48,802	54,964	41,356	59,356	44,008	33,208	30,963	767,470	767,470	0
.12	Above Ground Storage Tanks	14,896	29,680	(25,083)	18,284	7,819	2,322	1,361	727	2,527	55,862	627	781	109,803	109,803	0
.13	Low NOx	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
.14	Ash Pond Diversion Curtains	1,104	-	-	-	-	-	-	-	-	-	-	-	1,104	0	1,104
.15	Mercury Emissions	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
.16	Sodium Injection	-	7,614	-	7,794	9,182	8,374	10,200	1,000	10,200	1,000	10,200	1,000	66,564	0	66,564
.17	Gulf Coast Ozone Study	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
.18	SPCC Substation Project	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
.19	FDEP NOx Reduction Agreement	186,059	233,378	122,619	111,846	109,076	261,140	170,957	166,136	133,830	148,346	133,830	159,834	1,937,051	0	1,937,051
.20	CAIR/CAMR/CAVR Compliance Program	212,902	843,643	824,707	972,804	900,561	1,129,062	1,332,835	1,392,161	1,191,724	1,162,417	1,430,350	2,442,866	13,836,032	0	13,836,032
.21	MACT ICR	-	-	-	-	16,000	12,270	(16,000)	(12,270)	-	-	-	-	0	0	0
.22	Crist Water Conservation	11,170	309	(5,754)	1,867	(634)	1,986	5,700	55,700	55,700	5,700	5,700	7,500	144,944	144,944	0
.23	Mercury Allowances	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
.24	Annual NOx Allowances	465,831	166,384	163,665	164,212	290,031	337,133	340,194	350,013	300,176	277,343	215,764	194,838	3,265,584	0	3,265,584
.25	Seasonal NOx Allowances	-	-	-	-	724	1,138	1,164	1,198	11,629	-	-	-	15,853	0	15,853
.26	SO2 Allowances	78,040	57,435	50,072	74,901	117,095	109,698	153,508	159,811	139,508	130,885	88,792	79,328	1,239,073	0	1,239,073
2	Total of O & M Activities	1,244,636	2,209,967	1,494,967	1,660,870	1,705,491	2,341,510	2,310,900	2,544,271	2,272,986	2,141,646	2,288,004	3,176,280	25,391,528	3,572,945	21,818,583
3	Recoverable Costs Allocated to Energy	989,406	2,000,261	1,209,541	1,378,933	1,487,169	1,933,673	2,062,909	2,115,425	1,844,003	1,785,067	2,062,386	2,949,810	21,818,583		
4	Recoverable Costs Allocated to Demand	255,230	209,706	285,426	281,937	218,322	407,837	247,991	428,846	428,983	356,579	225,618	226,470	3,572,945		
5	Retail Energy Jurisdictional Factor	0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450			
6	Retail Demand Jurisdictional Factor	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582			
7	Jurisdictional Energy Recoverable Costs (A)	952,796	1,936,803	1,171,206	1,339,037	1,440,461	1,876,171	1,998,552	2,048,024	1,784,308	1,728,406	1,991,841	2,844,855	21,112,460		
8	Jurisdictional Demand Recoverable Costs (B)	246,158	202,252	275,281	271,917	210,563	393,342	239,177	413,604	413,736	343,906	217,599	218,421	3,445,956		
9	Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8)	1,198,954	2,139,055	1,446,487	1,610,954	1,651,024	2,269,513	2,237,729	2,461,628	2,198,044	2,072,312	2,209,440	3,063,276	24,558,416		

Notes:
(A) Line 3 x Line 5 x line loss multiplier
(B) Line 4 x Line 6

Schedule 6E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

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

Line		(1) Estimated/ Actual	(2) Original Projected	(3) Variance Amount	(4) Variance Percent
1	Description of Investment Projects				
.1	Air Quality Assurance Testing	68,016	35,656	32,360	90.8 %
.2	Crist 5, 6 & 7 Precipitator Projects	2,121,013	2,003,803	117,210	5.8 %
.3	Crist 7 Flue Gas Conditioning	167,953	167,953	0	0.0 %
.4	Low NOx Burners, Crist 6 & 7	1,976,056	1,976,056	0	0.0 %
.5	CEMS - Plnts Crist Scholz, Smith & Daniel	1,413,429	1,341,821	71,608	5.3 %
.6	Sub. Contam. Mobile Groundwater Treat. Sys.	98,926	95,407	3,519	3.7 %
.7	Raw Water Well Flowmeters - Plants Crist & Smith	26,393	26,393	0	0.0 %
.8	Crist Cooling Tower Cell	58,789	58,787	2	0.0 %
.9	Crist 1-5 Dechlorination	29,359	25,823	3,536	13.7 %
.10	Crist Diesel Fuel Oil Remediation	6,541	6,541	0	0.0 %
.11	Crist Bulk Tanker Unload Sec Contain Struc	8,589	8,589	0	0.0 %
.12	Crist IWW Sampling System	5,007	5,007	0	0.0 %
.13	Sodium Injection System	47,340	47,340	0	0.0 %
.14	Smith Stormwater Collection System	253,964	253,964	0	0.0 %
.15	Smith Waste Water Treatment Facility	35,976	35,978	(2)	(0.0) %
.16	Daniel Ash Management Project	2,041,884	2,061,461	(19,577)	(0.9) %
.17	Smith Water Conservation	91,379	548,074	(456,695)	(83.3) %
.18	Underground Fuel Tank Replacement	0	0	0	0.0 %
.19	Crist FDEP Agreement for Ozone Attainment	16,920,040	17,000,797	(80,757)	(0.5) %
.20	SPCC Compliance	122,102	122,104	(2)	(0.0) %
.21	*Crist Common FTIR Monitor*	7,589	7,589	0	0.0 %
.22	Precipitator Upgrades for CAM Compliance	3,960,080	3,960,078	2	0.0 %
.23	Plant Groundwater Investigation	0	0	0	0.0 %
.24	Crist Water Conservation	2,772,266	2,615,661	156,605	6.0 %
.25	Plant NPDES Permit Compliance Projects	783,276	778,485	4,791	0.6 %
.26	CAIR/CAMR/CAVR Compliance	92,998,925	92,656,603	342,322	0.4 %
.27	General Water Quality	7,873	7,873	0	0.0 %
.28	Mercury Allowances	0	0	0	0.0 %
.29	Annual Nox Allowances	324,270	269,666	54,604	20.2 %
.30	Seasonal Nox Allowances	277	1,418	(1,141)	(80.5) %
.31	SO2 Allowances	938,481	872,742	65,739	7.5 %
2	Total Investment Projects - Recoverable Costs	127,285,793	126,991,669	294,124	0.2 %
3	Recoverable Costs Allocated to Energy	121,431,341	120,853,072	578,269	0.5 %
4	Recoverable Costs Allocated to Demand	5,854,452	6,138,597	(284,145)	(4.6) %

Notes:
Column (1) is the End of Period Totals on Schedule 7E
Column (2) is the approved Projected amount in accordance with FPSC Order No. PSC-10-0683-FOF-EI
Column (3) = Column (1) - Column (2)
Column (4) = Column (3) / Column (2)

Docket No. 110007-EI
ECRC 2011 Est/Act True-UP
Exhibit RWD-2, Page 7 of 39

Schedule 7E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Capital Investment Projects - Recoverable Costs
(in Dollars)

Line		Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount	Method of Classification Demand	Energy
1	Description of Investment Projects (A)															
.1	Air Quality Assurance Testing	5,885	5,845	5,806	5,767	5,727	5,688	5,648	5,609	5,569	5,530	5,491	5,451	68,016	0	68,016
.2	Crist 5, 6 & 7 Precipitator Projects	153,835	158,464	159,806	156,825	156,992	158,008	163,081	175,797	186,546	194,131	216,330	241,198	2,121,013	0	2,121,013
.3	Crist 7 Flue Gas Conditioning	14,008	14,005	14,003	14,001	13,999	13,997	13,995	13,993	13,991	13,989	13,987	13,985	167,953	0	167,953
.4	Low NOx Burners, Crist 6 & 7	166,048	165,798	165,548	165,297	165,047	164,797	164,546	164,296	164,045	163,795	163,545	163,294	1,976,056	0	1,976,056
.5	CEMS - Plnts Crist Scholz, Smith & Daniel	118,104	118,145	118,100	118,000	117,806	117,690	117,800	117,837	117,787	117,586	117,387	117,187	1,413,429	0	1,413,429
.6	Sub. Contam. Mobile Groundwater Treat. Sys.	8,038	8,022	8,006	7,990	7,975	7,958	7,943	8,645	8,621	8,599	8,576	8,553	98,926	91,317	7,609
.7	Raw Water Well Flowmeters - Plants Crist & Smith	2,235	2,229	2,222	2,216	2,209	2,203	2,197	2,190	2,183	2,176	2,170	2,163	26,393	24,365	2,028
.8	Crist Cooling Tower Cell	4,907	4,906	4,905	4,903	4,902	4,900	4,898	4,897	4,896	4,893	4,892	4,890	58,789	54,268	4,521
.9	Crist 1-5 Dechlorination	2,198	2,189	2,181	2,173	2,165	2,156	2,148	2,139	2,366	2,830	3,293	3,521	29,359	27,100	2,259
.10	Crist Diesel Fuel Oil Remediation	556	554	552	549	548	546	544	542	540	539	536	535	6,541	6,038	503
.11	Crist Bulk Tanker Unload Sec Contain Struc	731	729	726	722	720	717	715	712	708	706	703	700	8,589	7,929	660
.12	Crist IWW Sampling System	426	424	423	422	419	418	417	415	413	412	410	408	5,007	4,621	386
.13	Sodium Injection System	4,003	3,993	3,983	3,971	3,961	3,950	3,940	3,929	3,918	3,908	3,898	3,886	47,340	0	47,340
.14	Smith Stormwater Collection System	21,561	21,489	21,416	21,344	21,272	21,200	21,128	21,055	20,983	20,911	20,839	20,766	253,964	234,428	19,536
.15	Smith Waste Water Treatment Facility	3,023	3,019	3,014	3,010	3,004	3,000	2,996	2,991	2,987	2,982	2,977	2,973	35,976	33,208	2,768
.16	Daniel Ash Management Project	172,058	171,873	171,702	171,288	170,861	170,430	170,051	169,609	169,166	168,724	168,282	167,840	2,041,884	1,884,815	157,069
.17	Smith Water Conservation	1,385	1,381	1,377	1,373	1,369	1,367	1,363	1,360	1,356	9,686	26,349	43,013	91,379	84,349	7,030
.18	Underground Fuel Tank Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
.19	Crist FDEP Agreement for Ozone Attainment	1,443,106	1,440,577	1,437,095	1,432,068	1,408,707	1,405,092	1,401,560	1,397,863	1,394,115	1,390,367	1,386,619	1,382,871	16,920,040	0	16,920,040
.20	SPCC Compliance	10,316	10,290	10,265	10,239	10,213	10,188	10,163	10,137	10,111	10,086	10,060	10,034	122,102	112,706	9,396
.21	Crist Common FTIR Monitor	642	640	639	636	635	634	631	630	628	626	625	623	7,589	0	7,589
.22	Precipitator Upgrades for CAM Compliance	334,390	333,593	332,795	332,000	331,203	330,406	329,608	328,811	328,014	327,217	326,420	325,623	3,960,080	0	3,960,080
.23	Plant Groundwater Investigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
.24	Crist Water Conservation	230,141	229,693	229,683	230,093	230,950	231,414	231,261	231,004	230,876	231,390	232,484	233,277	2,772,266	2,559,016	213,250
.25	Plant NPDES Permit Compliance Projects	65,768	65,606	65,440	65,274	65,109	64,943	64,778	64,612	64,801	65,343	65,766	65,836	783,276	723,024	60,252
.26	CAIR/CAMR/CAVR Compliance	7,799,526	7,780,004	7,764,772	7,750,112	7,737,455	7,727,272	7,742,220	7,780,465	7,759,991	7,739,515	7,719,042	7,698,551	92,998,925	0	92,998,925
.27	General Water Quality	684	679	674	669	664	659	653	648	643	638	633	629	7,873	7,268	605
.28	Mercury Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
.29	Annual NOx Allowances	40,574	37,592	36,035	34,489	32,346	29,387	26,192	22,937	19,870	17,146	14,819	12,883	324,270	0	324,270
.30	Seasonal NOx Allowances	44	44	44	44	40	31	20	9	1	0	0	0	277	0	277
.31	SO2 Allowances	83,170	82,531	82,011	81,409	80,503	79,433	78,192	76,714	75,302	74,027	72,991	72,198	938,481	0	938,481
2	Total Investment Projects - Recoverable Costs	10,687,362	10,664,314	10,643,223	10,616,884	10,576,801	10,558,484	10,568,688	10,609,846	10,590,427	10,577,752	10,589,124	10,602,888	127,285,793	5,854,452	121,431,341
3	Recoverable Costs Allocated to Energy	10,203,646	10,181,468	10,160,837	10,134,793	10,094,602	10,076,547	10,087,529	10,128,966	10,109,828	10,088,598	10,083,306	10,081,221	121,431,341		
4	Recoverable Costs Allocated to Demand	483,716	482,846	482,386	482,091	482,199	481,937	481,159	480,880	480,599	489,154	505,818	521,667	5,854,452		
5	Retail Energy Jurisdictional Factor	0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450			
6	Retail Demand Jurisdictional Factor	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582			
7	Jurisdictional Energy Recoverable Costs (B)	9,826,091	9,858,463	9,838,798	9,841,568	9,777,560	9,776,900	9,772,828	9,806,241	9,782,548	9,768,369	9,738,399	9,722,527	117,510,292		
8	Jurisdictional Demand Recoverable Costs (C)	466,524	465,685	465,241	464,957	465,061	464,808	464,058	463,789	463,518	471,769	487,840	503,126	5,646,376		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	10,292,615	10,324,148	10,304,039	10,306,525	10,242,621	10,241,708	10,236,886	10,270,030	10,246,066	10,240,138	10,226,239	10,225,653	123,156,668		

Notes:

(A) Pages 1-27 of Schedule 8E, Line 9, Pages 28-31 of Schedule 8E, Line 6
(B) Line 3 x Line 5 x Line loss multiplier
(C) Line 4 x Line 6

Schedule 8E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Air Quality Assurance Testing
P.E.s 1006 & 1244
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	
3	Less: Accumulated Depreciation (C)	(167,623)	(171,799)	(175,975)	(180,151)	(184,327)	(188,503)	(192,679)	(196,855)	(201,031)	(205,207)	(209,383)	(213,559)	(217,735)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	183,189	179,013	174,837	170,661	166,485	162,309	158,133	153,957	149,781	145,605	141,429	137,253	133,077	
6	Average Net Investment		181,101	176,925	172,749	168,573	164,397	160,221	156,045	151,869	147,693	143,517	139,341	135,165	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,331	1,300	1,269	1,239	1,208	1,178	1,146	1,116	1,085	1,054	1,024	993	13,943
	b Debt Component (Line 6 x Debt Component x 1/12)		378	369	361	352	343	334	326	317	308	300	291	282	3,961
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		4,176	4,176	4,176	4,176	4,176	4,176	4,176	4,176	4,176	4,176	4,176	4,176	50,112
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Annual NOx Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		5,885	5,845	5,806	5,767	5,727	5,688	5,648	5,609	5,569	5,530	5,491	5,451	68,016
	a Recoverable Costs Allocated to Energy		5,885	5,845	5,806	5,767	5,727	5,688	5,648	5,609	5,569	5,530	5,491	5,451	68,016
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		5,667	5,660	5,622	5,600	5,547	5,519	5,472	5,430	5,389	5,354	5,303	5,257	65,820
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		5,667	5,660	5,622	5,600	5,547	5,519	5,472	5,430	5,389	5,354	5,303	5,257	65,820

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Applicable depreciation rate or rates
(F) PE 1244 7 year amorization; PE 1006 fully amortized
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Docket No. 110007-EI
ECRC 2011 Est/Act True-UP
Exhibit RWD-2, Page 8 of 39

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 5, 6 & 7 Precipitator Projects
P.E.s 1038, 1119, 1216, 1243, 1249
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		110,440	962,561	(587,124)	47,178	81,149	225,836	938,128	1,845,555	520,836	1,174,867	3,618,842	1,756,998	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		4,216	5,353	5,163	4,279	3,913	5,927	6,825	6,825	6,825	6,825	6,825	(9,280)	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	13,909,529	13,909,529	13,909,529	13,909,529	13,909,529	13,909,529	13,909,529	13,909,529	13,909,529	13,909,529	13,909,529	13,909,529	13,909,529	
3	Less: Accumulated Depreciation (C)	(3,477,093)	(3,523,540)	(3,568,850)	(3,614,350)	(3,660,734)	(3,707,484)	(3,752,220)	(3,796,058)	(3,839,896)	(3,883,734)	(3,927,572)	(3,971,410)	(4,031,353)	
4	CWIP - Non Interest Bearing	471,744	582,184	1,544,745	957,621	1,004,799	1,085,948	1,311,784	2,249,912	4,095,467	4,616,303	5,791,170	9,410,012	11,167,010	
5	Net Investment (Lines 2 + 3 + 4)	10,904,180	10,968,173	11,885,424	11,252,800	11,253,594	11,287,993	11,469,093	12,363,383	14,165,100	14,642,098	15,773,127	19,348,131	21,045,186	
6	Average Net Investment		10,936,177	11,426,799	11,569,112	11,253,197	11,270,794	11,378,543	11,916,238	13,264,242	14,403,599	15,207,613	17,560,629	20,196,659	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		80,348	83,953	84,998	82,677	82,807	83,598	87,549	97,452	105,823	111,730	129,018	148,385	1,178,338
	b Debt Component (Line 6 x Debt Component x 1/12)		22,824	23,848	24,145	23,485	23,522	23,747	24,869	27,682	30,060	31,738	36,649	42,150	334,719
8	Investment Expenses														
	a Depreciation (E)		40,574	40,574	40,574	40,574	40,574	40,574	40,574	40,574	40,574	40,574	40,574	40,574	486,888
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		10,089	10,089	10,089	10,089	10,089	10,089	10,089	10,089	10,089	10,089	10,089	10,089	121,068
	d Annual NOx Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		153,835	158,464	159,806	156,825	156,992	158,008	163,081	175,797	186,546	194,131	216,330	241,198	2,121,013
	a Recoverable Costs Allocated to Energy		153,835	158,464	159,806	156,825	156,992	158,008	163,081	175,797	186,546	194,131	216,330	241,198	2,121,013
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		148,143	153,437	154,741	152,289	152,061	153,309	157,993	170,196	180,507	187,969	208,930	232,616	2,052,191
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		148,143	153,437	154,741	152,289	152,061	153,309	157,993	170,196	180,507	187,969	208,930	232,616	2,052,191

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) 3.5% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 7 Flue Gas Conditioning
P.E. 1228
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	1,462,270	1,462,057	1,461,844	1,461,631	1,461,418	1,461,205	1,460,992	1,460,779	1,460,566	1,460,353	1,460,140	1,459,927	1,459,714	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	1,462,270	1,462,057	1,461,844	1,461,631	1,461,418	1,461,205	1,460,992	1,460,779	1,460,566	1,460,353	1,460,140	1,459,927	1,459,714	
6	Average Net Investment		1,462,164	1,461,951	1,461,738	1,461,525	1,461,312	1,461,099	1,460,886	1,460,673	1,460,460	1,460,247	1,460,034	1,459,821	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		10,743	10,741	10,739	10,738	10,736	10,735	10,733	10,732	10,730	10,728	10,727	10,725	128,807
	b Debt Component (Line 6 x Debt Component x 1/12)		3,052	3,051	3,051	3,050	3,050	3,049	3,049	3,048	3,048	3,048	3,047	3,047	36,590
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		213	213	213	213	213	213	213	213	213	213	213	213	2,556
	d Annual NOx Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		14,008	14,005	14,003	14,001	13,999	13,997	13,995	13,993	13,991	13,989	13,987	13,985	167,953
	a Recoverable Costs Allocated to Energy		14,008	14,005	14,003	14,001	13,999	13,997	13,995	13,993	13,991	13,989	13,987	13,985	167,953
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		13,490	13,561	13,559	13,596	13,559	13,581	13,558	13,547	13,538	13,545	13,509	13,487	162,530
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		13,490	13,561	13,559	13,596	13,559	13,581	13,558	13,547	13,538	13,545	13,509	13,487	162,530

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Docket No. 110007-EI
ECRC 2011 Est/Act True-UP
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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burners, Crist 6 & 7
P.E.s 1234, 1236, 1242, 1284
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	
3	Less: Accumulated Depreciation (C)	5,703,311	5,676,772	5,650,233	5,623,694	5,597,155	5,570,616	5,544,077	5,517,538	5,490,999	5,464,460	5,437,921	5,411,382	5,384,843	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	14,801,235	14,774,696	14,748,157	14,721,618	14,695,079	14,668,540	14,642,001	14,615,462	14,588,923	14,562,384	14,535,845	14,509,306	14,482,767	
6	Average Net Investment		14,787,966	14,761,427	14,734,888	14,708,349	14,681,810	14,655,271	14,628,732	14,602,193	14,575,654	14,549,115	14,522,576	14,496,037	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		108,647	108,452	108,257	108,062	107,867	107,672	107,477	107,282	107,087	106,892	106,697	106,502	1,290,894
	b Debt Component (Line 6 x Debt Component x 1/12)		30,862	30,807	30,752	30,696	30,641	30,586	30,530	30,475	30,419	30,364	30,309	30,253	366,694
8	Investment Expenses														
	a Depreciation (E)		26,539	26,539	26,539	26,539	26,539	26,539	26,539	26,539	26,539	26,539	26,539	26,539	318,468
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Annual NOx Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		166,048	165,798	165,548	165,297	165,047	164,797	164,546	164,296	164,045	163,795	163,545	163,294	1,976,056
	a Recoverable Costs Allocated to Energy		166,048	165,798	165,548	165,297	165,047	164,797	164,546	164,296	164,045	163,795	163,545	163,294	1,976,056
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		159,904	160,538	160,301	160,515	159,863	159,896	159,413	159,061	158,734	158,596	157,951	157,484	1,912,256
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		159,904	160,538	160,301	160,515	159,863	159,896	159,413	159,061	158,734	158,596	157,951	157,484	1,912,256

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Docket No. 110007-EI
ECRC 2011 Est/Act True-UP
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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: CEMS - Plnts Crist Scholz, Smith & Daniel
P.E.s 1001, 1060, 1154, 1164, 1217, 1240, 1245, 1247, 1256, 1283, 1286, 1289, 1290, 1311, 1316, 1323, 1324, 1357, 1364, 1440, 1441, 1442, 1444, 1454, 1459, 1460, 1558, 1570, 1592, 1658, 1829 & 1830
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
a	Expenditures/Additions		24,270	10,965	14,649	(1,068)	1,054	15,838	35,000	10,000	0	0	0	0	
b	Clearings to Plant		24,270	10,918	11,998	1,630	1,054	15,838	0	45,000	0	0	0	0	
c	Retirements		0	0	0	0	0	0	0	10,000	0	0	0	0	
d	Cost of Removal		0	0	0	0	0	0	5,000	0	0	0	0	0	
e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	7,161,788	7,186,058	7,196,976	7,208,974	7,210,604	7,211,658	7,227,496	7,227,496	7,262,496	7,262,496	7,262,496	7,262,496	7,262,496	
3	Less: Accumulated Depreciation (C)	3,008,313	2,987,423	2,966,462	2,945,469	2,924,441	2,903,410	2,882,376	2,866,296	2,855,216	2,834,034	2,812,852	2,791,670	2,770,488	
4	CWIP - Non Interest Bearing	0	0	47	2,698	0	0	0	35,000	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	10,170,101	10,173,481	10,163,485	10,157,141	10,135,045	10,115,068	10,109,872	10,128,792	10,117,712	10,096,530	10,075,348	10,054,166	10,032,984	
6	Average Net Investment		10,171,791	10,168,483	10,160,313	10,146,093	10,125,057	10,112,470	10,119,332	10,123,252	10,107,121	10,085,939	10,064,757	10,043,575	
7	Return on Average Net Investment														
a	Equity Component (Line 6 x Equity Component x 1/12) (D)		74,731	74,708	74,648	74,543	74,390	74,297	74,347	74,376	74,257	74,101	73,946	73,790	892,134
b	Debt Component (Line 6 x Debt Component x 1/12)		21,229	21,222	21,205	21,175	21,131	21,105	21,119	21,127	21,094	21,049	21,005	20,961	253,422
8	Investment Expenses														
a	Depreciation (E)		20,662	20,733	20,765	20,800	20,803	20,806	20,852	20,852	20,954	20,954	20,954	20,954	250,089
b	Amortization (F)		228	228	228	228	228	228	228	228	228	228	228	228	2,736
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Annual NOx Allowance Expense		1,254	1,254	1,254	1,254	1,254	1,254	1,254	1,254	1,254	1,254	1,254	1,254	15,048
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		118,104	118,145	118,100	118,000	117,806	117,690	117,800	117,837	117,787	117,586	117,387	117,187	1,413,429
a	Recoverable Costs Allocated to Energy		118,104	118,145	118,100	118,000	117,806	117,690	117,800	117,837	117,787	117,586	117,387	117,187	1,413,429
b	Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		113,734	114,397	114,357	114,586	114,106	114,190	114,125	114,083	113,974	113,854	113,372	113,017	1,367,795
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		113,734	114,397	114,357	114,586	114,106	114,190	114,125	114,083	113,974	113,854	113,372	113,017	1,367,795

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist, $3,928,834; Scholz $916,802 Smith $1,734,877; Daniel $581,276. Ending Balances: Crist, $4,026,449; Scholz $916,802; Smith $1,734,877; Daniel $584,368.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Crist: 3.5%; Smith 3.3%; Scholz 4.1%; Daniel 2.8% annually
(F) PE 1364 & 1658 have a 7 year amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Docket No. 110007-EI
ECRC 2011 Est/Act True-UP
Exhibit RWD-2, Page 12 of 39

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Sub. Contam. Mobile Groundwater Treat. Sys.
P.E. 1007, 3400, & 3412
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	
3	Less: Accumulated Depreciation (C)	(243,560)	(245,243)	(246,926)	(248,609)	(250,292)	(251,975)	(253,658)	(255,341)	(257,745)	(260,149)	(262,553)	(264,957)	(267,361)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	674,464	672,781	671,098	669,415	667,732	666,049	664,366	662,683	660,279	657,875	655,471	653,067	650,663	
6	Average Net Investment		673,623	671,940	670,257	668,574	666,891	665,208	663,525	661,481	659,077	656,673	654,269	651,865	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		4,949	4,937	4,924	4,912	4,900	4,887	4,875	4,860	4,842	4,825	4,807	4,789	58,507
	b Debt Component (Line 6 x Debt Component x 1/12)		1,406	1,402	1,399	1,395	1,392	1,388	1,385	1,381	1,375	1,370	1,365	1,360	16,618
8	Investment Expenses														
	a Depreciation (E)		1,683	1,683	1,683	1,683	1,683	1,683	1,683	2,404	2,404	2,404	2,404	2,404	23,801
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Annual NOx Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		8,038	8,022	8,006	7,990	7,975	7,958	7,943	8,645	8,621	8,599	8,576	8,553	98,926
	a Recoverable Costs Allocated to Energy		618	617	616	615	613	612	611	665	663	661	660	658	7,609
	b Recoverable Costs Allocated to Demand		7,420	7,405	7,390	7,375	7,362	7,346	7,332	7,980	7,958	7,938	7,916	7,895	91,317
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		595	597	596	597	594	594	592	644	642	640	637	635	7,363
13	Retail Demand-Related Recoverable Costs (I)		7,156	7,142	7,127	7,113	7,100	7,085	7,071	7,696	7,675	7,656	7,635	7,614	88,070
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		7,751	7,739	7,723	7,710	7,694	7,679	7,663	8,340	8,317	8,296	8,272	8,249	95,433

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Part of PE 1007 depreciable at 2.2% annually, PEs 3400 and 3412 depreciable at 2.2% annually
(F) The amortizable portion of PE 1007 is fully amortized
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Raw Water Well Flowmeters - Plants Crist & Smith
P.E. 1155 & 1606
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	
3	Less: Accumulated Depreciation (C)	(79,139)	(79,832)	(80,525)	(81,218)	(81,911)	(82,604)	(83,297)	(83,990)	(84,683)	(85,376)	(86,069)	(86,762)	(87,455)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	163,834	163,141	162,448	161,755	161,062	160,369	159,676	158,983	158,290	157,597	156,904	156,211	155,518	
6	Average Net Investment		163,488	162,795	162,102	161,409	160,716	160,023	159,330	158,637	157,944	157,251	156,558	155,865	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,201	1,196	1,191	1,186	1,181	1,176	1,171	1,166	1,160	1,155	1,150	1,145	14,078
	b Debt Component (Line 6 x Debt Component x 1/12)		341	340	338	337	335	334	333	331	330	328	327	325	3,999
8	Investment Expenses														
	a Depreciation (E)		693	693	693	693	693	693	693	693	693	693	693	693	8,316
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Annual NOx Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,235	2,229	2,222	2,216	2,209	2,203	2,197	2,190	2,183	2,176	2,170	2,163	26,393
	a Recoverable Costs Allocated to Energy		172	171	171	170	170	169	169	168	168	167	167	166	2,028
	b Recoverable Costs Allocated to Demand		2,063	2,058	2,051	2,046	2,039	2,034	2,028	2,022	2,015	2,009	2,003	1,997	24,365
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		166	166	166	165	165	164	164	163	163	162	161	160	1,965
13	Retail Demand-Related Recoverable Costs (I)		1,990	1,985	1,978	1,973	1,967	1,962	1,956	1,950	1,943	1,938	1,932	1,926	23,500
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,156	2,151	2,144	2,138	2,132	2,126	2,120	2,113	2,106	2,100	2,093	2,086	25,465

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning and Ending Balances: Crist, $149,950; Smith $93,023.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Crist 3.5%; Smith 3.3% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Schedule 8E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Cooling Tower Cell
P.E. 1232
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	502,395	502,226	502,057	501,888	501,719	501,550	501,381	501,212	501,043	500,874	500,705	500,536	500,367	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	502,395	502,226	502,057	501,888	501,719	501,550	501,381	501,212	501,043	500,874	500,705	500,536	500,367	
6	Average Net Investment		502,311	502,142	501,973	501,804	501,635	501,466	501,297	501,128	500,959	500,790	500,621	500,452	
7	Return on Average Net Investment														
a	Equity Component (Line 6 x Equity Component x 1/12) (D)		3,690	3,689	3,688	3,687	3,686	3,684	3,683	3,682	3,681	3,679	3,678	3,677	44,204
b	Debt Component (Line 6 x Debt Component x 1/12)		1,048	1,048	1,048	1,047	1,047	1,047	1,046	1,046	1,046	1,045	1,045	1,044	12,557
8	Investment Expenses														
a	Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		169	169	169	169	169	169	169	169	169	169	169	169	2,028
d	Annual NOx Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		4,907	4,906	4,905	4,903	4,902	4,900	4,898	4,897	4,896	4,893	4,892	4,890	58,789
a	Recoverable Costs Allocated to Energy		377	377	377	377	377	377	377	377	377	376	376	376	4,521
b	Recoverable Costs Allocated to Demand		4,530	4,529	4,528	4,526	4,525	4,523	4,521	4,520	4,519	4,517	4,516	4,514	54,268
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		363	365	365	366	365	366	365	365	365	364	363	363	4,375
13	Retail Demand-Related Recoverable Costs (I)		4,369	4,368	4,367	4,365	4,364	4,362	4,360	4,359	4,358	4,356	4,355	4,354	52,337
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		4,732	4,733	4,732	4,731	4,729	4,728	4,725	4,724	4,723	4,720	4,718	4,717	56,712

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

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ECRC 2011 Est/Act True-UP
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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 1-5 Dechlorination
P.E. 1248, 1180
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
a	Expenditures/Additions		0	0	0	0	0	0	0	0	50,000	50,000	50,000	0	
b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	150,000	
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	305,323	455,323	
3	Less: Accumulated Depreciation (C)	(166,318)	(167,209)	(168,100)	(168,991)	(169,882)	(170,773)	(171,664)	(172,555)	(173,446)	(174,337)	(175,228)	(176,119)	(177,010)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	50,000	100,000	150,000	0	
5	Net Investment (Lines 2 + 3 + 4)	139,005	138,114	137,223	136,332	135,441	134,550	133,659	132,768	131,877	180,986	230,095	279,204	278,313	
6	Average Net Investment		138,560	137,669	136,778	135,887	134,996	134,105	133,214	132,323	156,432	205,541	254,650	278,759	
7	Return on Average Net Investment														
a	Equity Component (Line 6 x Equity Component x 1/12) (D)		1,018	1,011	1,005	998	992	985	979	972	1,149	1,510	1,871	2,048	14,538
b	Debt Component (Line 6 x Debt Component x 1/12)		289	287	285	284	282	280	278	276	326	429	531	582	4,129
8	Investment Expenses														
a	Depreciation (E)		891	891	891	891	891	891	891	891	891	891	891	891	10,692
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Annual NOx Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,198	2,189	2,181	2,173	2,165	2,156	2,148	2,139	2,366	2,830	3,293	3,521	29,359
a	Recoverable Costs Allocated to Energy		169	168	168	167	167	166	165	165	182	218	253	271	2,259
b	Recoverable Costs Allocated to Demand		2,029	2,021	2,013	2,006	1,998	1,990	1,983	1,974	2,184	2,612	3,040	3,250	27,100
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		163	163	163	162	162	161	160	160	176	211	244	261	2,186
13	Retail Demand-Related Recoverable Costs (I)		1,957	1,949	1,941	1,935	1,927	1,919	1,913	1,904	2,106	2,519	2,932	3,134	26,136
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,120	2,112	2,104	2,097	2,089	2,080	2,073	2,064	2,282	2,730	3,176	3,395	28,322

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Diesel Fuel Oil Remediation
P.E. 1270
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	
3	Less: Accumulated Depreciation (C)	(31,243)	(31,444)	(31,645)	(31,846)	(32,047)	(32,248)	(32,449)	(32,650)	(32,851)	(33,052)	(33,253)	(33,454)	(33,655)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	37,680	37,479	37,278	37,077	36,876	36,675	36,474	36,273	36,072	35,871	35,670	35,469	35,268	
6	Average Net Investment		37,580	37,379	37,178	36,977	36,776	36,575	36,374	36,173	35,972	35,771	35,570	35,369	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		277	275	273	271	270	269	267	266	264	263	261	260	3,216
	b Debt Component (Line 6 x Debt Component x 1/12)		78	78	78	77	77	76	76	75	75	75	74	74	913
8	Investment Expenses														
	a Depreciation (E)		201	201	201	201	201	201	201	201	201	201	201	201	2,412
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Annual NOx Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		556	554	552	549	548	546	544	542	540	539	536	535	6,541
	a Recoverable Costs Allocated to Energy		43	43	42	42	42	42	42	42	42	41	41	41	503
	b Recoverable Costs Allocated to Demand		513	511	510	507	506	504	502	500	498	498	495	494	6,038
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		41	42	41	41	41	41	41	41	41	40	40	40	490
13	Retail Demand-Related Recoverable Costs (I)		495	493	492	489	488	486	484	482	480	480	477	476	5,822
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		536	535	533	530	529	527	525	523	521	520	517	516	6,312

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Bulk Tanker Unload Sec Contain Struc
P.E. 1271
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	
3	Less: Accumulated Depreciation (C)	(55,220)	(55,516)	(55,812)	(56,108)	(56,404)	(56,700)	(56,996)	(57,292)	(57,588)	(57,884)	(58,180)	(58,476)	(58,772)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	46,275	45,979	45,683	45,387	45,091	44,795	44,499	44,203	43,907	43,611	43,315	43,019	42,723	
6	Average Net Investment		46,127	45,831	45,535	45,239	44,943	44,647	44,351	44,055	43,759	43,463	43,167	42,871	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		339	337	335	332	330	328	326	324	321	319	317	315	3,923
	b Debt Component (Line 6 x Debt Component x 1/12)		96	96	95	94	94	93	93	92	91	91	90	89	1,114
8	Investment Expenses														
	a Depreciation (E)		296	296	296	296	296	296	296	296	296	296	296	296	3,552
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Annual NOx Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		731	729	726	722	720	717	715	712	708	706	703	700	8,589
	a Recoverable Costs Allocated to Energy		56	56	56	56	55	55	55	55	54	54	54	54	660
	b Recoverable Costs Allocated to Demand		675	673	670	666	665	662	660	657	654	652	649	646	7,929
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		54	54	54	54	53	53	53	53	52	52	52	52	636
13	Retail Demand-Related Recoverable Costs (I)		651	649	646	642	641	638	637	634	631	629	626	623	7,647
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		705	703	700	696	694	691	690	687	683	681	678	675	8,283

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

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ECRC 2011 Est/Act True-UP
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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Crist IWW Sampling System
P.E. 1275
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	
3	Less: Accumulated Depreciation (C)	(32,713)	(32,887)	(33,061)	(33,235)	(33,409)	(33,583)	(33,757)	(33,931)	(34,105)	(34,279)	(34,453)	(34,627)	(34,801)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	26,830	26,656	26,482	26,308	26,134	25,960	25,786	25,612	25,438	25,264	25,090	24,916	24,742	
6	Average Net Investment		26,743	26,569	26,395	26,221	26,047	25,873	25,699	25,525	25,351	25,177	25,003	24,829	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		196	195	194	193	191	190	189	188	186	185	184	182	2,273
	b Debt Component (Line 6 x Debt Component x 1/12)		56	55	55	55	54	54	54	53	53	53	52	52	646
8	Investment Expenses														
	a Depreciation (E)		174	174	174	174	174	174	174	174	174	174	174	174	2,088
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Annual NOx Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		426	424	423	422	419	418	417	415	413	412	410	408	5,007
	a Recoverable Costs Allocated to Energy		33	33	33	32	32	32	32	32	32	32	32	31	386
	b Recoverable Costs Allocated to Demand		393	391	390	390	387	386	385	383	381	380	378	377	4,621
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		32	32	32	31	31	31	31	31	31	31	31	30	374
13	Retail Demand-Related Recoverable Costs (I)		379	377	376	376	373	372	371	369	367	366	365	364	4,455
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		411	409	408	407	404	403	402	400	398	397	396	394	4,829

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Sodium Injection System
P.E. 1214 & 1413
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	
3	Less: Accumulated Depreciation (C)	(85,239)	(86,362)	(87,485)	(88,608)	(89,731)	(90,854)	(91,977)	(93,100)	(94,223)	(95,346)	(96,469)	(97,592)	(98,715)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	305,880	304,757	303,634	302,511	301,388	300,265	299,142	298,019	296,896	295,773	294,650	293,527	292,404	
6	Average Net Investment		305,319	304,196	303,073	301,950	300,827	299,704	298,581	297,458	296,335	295,212	294,089	292,966	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,243	2,235	2,227	2,218	2,210	2,202	2,194	2,185	2,177	2,169	2,161	2,152	26,373
	b Debt Component (Line 6 x Debt Component x 1/12)		637	635	633	630	628	625	623	621	618	616	614	611	7,491
8	Investment Expenses														
	a Depreciation (E)		1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	13,476
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Annual NOx Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		4,003	3,993	3,983	3,971	3,961	3,950	3,940	3,929	3,918	3,908	3,898	3,886	47,340
	a Recoverable Costs Allocated to Energy		4,003	3,993	3,983	3,971	3,961	3,950	3,940	3,929	3,918	3,908	3,898	3,886	47,340
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		3,855	3,866	3,857	3,856	3,837	3,833	3,817	3,804	3,791	3,784	3,765	3,748	45,813
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		3,855	3,866	3,857	3,856	3,837	3,833	3,817	3,804	3,791	3,784	3,765	3,748	45,813

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning and Ending Balances: Crist $284,622 and Smith $106,497.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Crist 3.5% annually; Smith 3.3% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Stormwater Collection System
P.E. 1446
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	
3	Less: Accumulated Depreciation (C)	(1,304,450)	(1,312,102)	(1,319,754)	(1,327,406)	(1,335,058)	(1,342,710)	(1,350,362)	(1,358,014)	(1,365,666)	(1,373,318)	(1,380,970)	(1,388,622)	(1,396,274)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	1,478,150	1,470,498	1,462,846	1,455,194	1,447,542	1,439,890	1,432,238	1,424,586	1,416,934	1,409,282	1,401,630	1,393,978	1,386,326	
6	Average Net Investment		1,474,324	1,466,672	1,459,020	1,451,368	1,443,716	1,436,064	1,428,412	1,420,760	1,413,108	1,405,456	1,397,804	1,390,152	
7	Return on Average Net Investment														
a	Equity Component (Line 6 x Equity Component x 1/12) (D)		10,832	10,776	10,719	10,663	10,607	10,551	10,495	10,438	10,382	10,326	10,270	10,213	126,272
b	Debt Component (Line 6 x Debt Component x 1/12)		3,077	3,061	3,045	3,029	3,013	2,997	2,981	2,965	2,949	2,933	2,917	2,901	35,868
8	Investment Expenses														
a	Depreciation (E)		7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	91,824
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Annual NOx Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		21,561	21,489	21,416	21,344	21,272	21,200	21,128	21,055	20,983	20,911	20,839	20,766	253,964
a	Recoverable Costs Allocated to Energy		1,659	1,653	1,647	1,642	1,636	1,631	1,625	1,620	1,614	1,609	1,603	1,597	19,536
b	Recoverable Costs Allocated to Demand		19,902	19,836	19,769	19,702	19,636	19,569	19,503	19,435	19,369	19,302	19,236	19,169	234,428
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		1,598	1,601	1,595	1,594	1,585	1,582	1,574	1,568	1,562	1,558	1,548	1,540	18,905
13	Retail Demand-Related Recoverable Costs (I)		19,195	19,131	19,066	19,002	18,938	18,873	18,810	18,744	18,681	18,616	18,552	18,488	226,096
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		20,793	20,732	20,661	20,596	20,523	20,455	20,384	20,312	20,243	20,174	20,100	20,028	245,001

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) 3.3% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

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ECRC 2011 Est/Act True-UP
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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Waste Water Treatment Facility
P.E. 1466 & 1643
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
a	Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
b	Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	
3	Less: Accumulated Depreciation (C)	89,624	89,132	88,640	88,148	87,656	87,164	86,672	86,180	85,688	85,196	84,704	84,212	83,720	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	268,586	268,094	267,602	267,110	266,618	266,126	265,634	265,142	264,650	264,158	263,666	263,174	262,682	
6	Average Net Investment		268,340	267,848	267,356	266,864	266,372	265,880	265,388	264,896	264,404	263,912	263,420	262,928	
7	Return on Average Net Investment														
a	Equity Component (Line 6 x Equity Component x 1/12) (D)		1,971	1,968	1,964	1,961	1,956	1,953	1,950	1,946	1,943	1,939	1,935	1,932	23,418
b	Debt Component (Line 6 x Debt Component x 1/12)		560	559	558	557	556	555	554	553	552	551	550	549	6,654
8	Investment Expenses														
a	Depreciation (E)		492	492	492	492	492	492	492	492	492	492	492	492	5,904
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Annual NOx Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		3,023	3,019	3,014	3,010	3,004	3,000	2,996	2,991	2,987	2,982	2,977	2,973	35,976
a	Recoverable Costs Allocated to Energy		233	232	232	232	231	231	230	230	230	229	229	229	2,768
b	Recoverable Costs Allocated to Demand		2,790	2,787	2,782	2,778	2,773	2,769	2,766	2,761	2,757	2,753	2,748	2,744	33,208
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		224	225	225	225	224	224	223	223	223	222	221	221	2,680
13	Retail Demand-Related Recoverable Costs (I)		2,691	2,688	2,683	2,679	2,674	2,671	2,668	2,663	2,659	2,655	2,650	2,646	32,027
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,915	2,913	2,908	2,904	2,898	2,895	2,891	2,886	2,882	2,877	2,871	2,867	34,707

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) 3.3% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Daniel Ash Management Project
P.E. 1501, 1535, 1555, & 1819
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
a	Expenditures/Additions		584	7,681	146	2,479	266	415	0	0	0	0	0	0	
b	Clearings to Plant		0	0	0	0	0	34,288	0	0	0	0	0	0	
c	Retirements		0	0	0	0	0	10,458	0	0	0	0	0	0	
d	Cost of Removal		0	46,317	2,900	411	220	1,129	0	0	0	0	0	0	
e	Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	16,210,229	16,210,229	16,210,229	16,210,229	16,210,229	16,210,229	16,234,059	16,234,059	16,234,059	16,234,059	16,234,059	16,234,059	16,234,059	
3	Less: Accumulated Depreciation (C)	(5,965,442)	(6,012,256)	(6,012,753)	(6,056,667)	(6,103,070)	(6,149,664)	(6,184,891)	(6,231,761)	(6,278,631)	(6,325,501)	(6,372,371)	(6,419,241)	(6,466,111)	
4	CWIP - Non Interest Bearing	22,718	23,302	30,983	31,129	33,608	33,874	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	10,267,505	10,221,275	10,228,459	10,184,691	10,140,767	10,094,439	10,049,168	10,002,298	9,955,428	9,908,558	9,861,688	9,814,818	9,767,948	
6	Average Net Investment		10,244,390	10,224,867	10,206,575	10,162,729	10,117,603	10,071,804	10,025,733	9,978,863	9,931,993	9,885,123	9,838,253	9,791,383	
7	Return on Average Net Investment														
a	Equity Component (Line 6 x Equity Component x 1/12) (D)		75,266	75,122	74,989	74,666	74,334	73,998	73,659	73,315	72,970	72,626	72,282	71,937	885,164
b	Debt Component (Line 6 x Debt Component x 1/12)		21,380	21,339	21,301	21,210	21,115	21,020	20,924	20,826	20,728	20,630	20,532	20,435	251,440
8	Investment Expenses														
a	Depreciation (E)		37,818	37,818	37,818	37,818	37,818	37,818	37,874	37,874	37,874	37,874	37,874	37,874	454,152
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		8,996	8,996	8,996	8,996	8,996	8,996	8,996	8,996	8,996	8,996	8,996	8,996	107,952
d	Annual NOx Allowance Expense		28,598	28,598	28,598	28,598	28,598	28,598	28,598	28,598	28,598	28,598	28,598	28,598	343,176
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		172,058	171,873	171,702	171,288	170,861	170,430	170,051	169,609	169,166	168,724	168,282	167,840	2,041,884
a	Recoverable Costs Allocated to Energy		13,235	13,221	13,208	13,176	13,143	13,110	13,081	13,047	13,013	12,979	12,945	12,911	157,069
b	Recoverable Costs Allocated to Demand		158,823	158,652	158,494	158,112	157,718	157,320	156,970	156,562	156,153	155,745	155,337	154,929	1,884,815
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		12,745	12,802	12,789	12,795	12,730	12,720	12,673	12,631	12,592	12,567	12,502	12,452	151,998
13	Retail Demand-Related Recoverable Costs (I)		153,178	153,013	152,861	152,492	152,112	151,729	151,391	150,998	150,603	150,210	149,816	149,423	1,817,826
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		165,923	165,815	165,650	165,287	164,842	164,449	164,064	163,629	163,195	162,777	162,318	161,875	1,969,824

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) 2.8% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Schedule 8E
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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Water Conservation
P.E. 1601, 1620, 1638
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	1,766,667	1,766,667	1,766,667	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	
3	Less: Accumulated Depreciation (C)	(26,347)	(26,716)	(27,085)	(27,454)	(27,823)	(28,192)	(28,561)	(28,930)	(29,299)	(29,668)	(30,037)	(30,406)	(30,775)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	1,766,667	3,533,334	5,300,001	
5	Net Investment (Lines 2 + 3 + 4)	107,787	107,418	107,049	106,680	106,311	105,942	105,573	105,204	104,835	104,466	1,870,764	3,637,062	5,403,360	
6	Average Net Investment		107,603	107,234	106,865	106,496	106,127	105,758	105,389	105,020	104,651	987,615	2,753,913	4,520,211	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		791	788	785	782	779	777	774	772	769	7,256	20,233	33,210	67,716
	b Debt Component (Line 6 x Debt Component x 1/12)		225	224	223	222	221	221	220	219	218	2,061	5,747	9,434	19,235
8	Investment Expenses														
	a Depreciation (E)		369	369	369	369	369	369	369	369	369	369	369	369	4,428
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Annual NOx Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,385	1,381	1,377	1,373	1,369	1,367	1,363	1,360	1,356	9,686	26,349	43,013	91,379
	a Recoverable Costs Allocated to Energy		107	106	106	106	105	105	105	105	104	745	2,027	3,309	7,030
	b Recoverable Costs Allocated to Demand		1,278	1,275	1,271	1,267	1,264	1,262	1,258	1,255	1,252	8,941	24,322	39,704	84,349
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		103	103	103	103	102	102	102	102	101	721	1,958	3,191	6,791
13	Retail Demand-Related Recoverable Costs (I)		1,233	1,230	1,226	1,222	1,219	1,217	1,213	1,210	1,208	8,623	23,458	38,293	81,352
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,336	1,333	1,329	1,325	1,321	1,319	1,315	1,312	1,309	9,344	25,416	41,484	88,143

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) 3.3% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Docket No. 110007-EI
ECRC 2011 Est/Act True-UP
Exhibit RWD-2, Page 24 of 39

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Underground Fuel Tank Replacement
P.E. 4397
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	0	0	0	0	0	0	0	0	0	0	0	0	0	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 6 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Annual NOx Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Applicable depreciation rate or rates
(F) PE 4397 fully amortized.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Crist FDEP Agreement for Ozone Attainment
P.E. 1031, 1158, 1167, 1199, 1250, 1287
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		164,994	39,911	3,126	(3,148)	818	25,993	10,000	0	0	0	0	0	
	b Clearings to Plant		0	0	617,713	(3,148)	818	13,393	22,600	0	0	0	0	0	
	c Retirements		0	0	0	5,663,816	0	0	0	0	0	0	0	0	
	d Cost of Removal		52,693	30,220	12,762	5,148	145	1,042	0	0	0	0	0	0	
	e Salvage		0	0	0	640,000	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	129,425,427	129,425,427	129,425,427	130,043,140	124,376,176	124,376,994	124,390,387	124,412,987	124,412,987	124,412,987	124,412,987	124,412,987	124,412,987	
3	Less: Accumulated Depreciation (C)	(20,439,998)	(20,799,294)	(21,181,063)	(21,580,290)	(16,965,117)	(17,362,232)	(17,758,452)	(18,155,754)	(18,553,061)	(18,950,368)	(19,347,675)	(19,744,982)	(20,142,289)	
4	CWIP - Non Interest Bearing	409,683	574,677	614,588	0	0	0	12,600	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	109,395,112	109,200,810	108,858,952	108,462,850	107,411,059	107,014,762	106,644,535	106,257,233	105,859,926	105,462,619	105,065,312	104,668,005	104,270,698	
6	Average Net Investment		109,297,961	109,029,881	108,660,901	107,936,955	107,212,911	106,829,649	106,450,884	106,058,580	105,661,273	105,263,966	104,866,659	104,469,352	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		803,012	801,043	798,331	793,013	787,694	784,877	782,095	779,212	776,293	773,374	770,455	767,536	9,416,935
	b Debt Component (Line 6 x Debt Component x 1/12)		228,105	227,545	226,775	225,264	223,753	222,953	222,163	221,344	220,515	219,686	218,857	218,028	2,674,988
8	Investment Expenses														
	a Depreciation (E)		376,955	376,955	376,955	378,757	362,226	362,228	362,268	362,273	362,273	362,273	362,273	362,273	4,407,709
	b Amortization (F)		2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	2,364	28,368
	c Dismantlement		32,670	32,670	32,670	32,670	32,670	32,670	32,670	32,670	32,670	32,670	32,670	32,670	392,040
	d Annual NOx Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,443,106	1,440,577	1,437,095	1,432,068	1,408,707	1,405,092	1,401,560	1,397,863	1,394,115	1,390,367	1,386,619	1,382,871	16,920,040
	a Recoverable Costs Allocated to Energy		1,443,106	1,440,577	1,437,095	1,432,068	1,408,707	1,405,092	1,401,560	1,397,863	1,394,115	1,390,367	1,386,619	1,382,871	16,920,040
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		1,389,708	1,394,875	1,391,547	1,390,635	1,364,464	1,363,309	1,357,836	1,353,325	1,348,984	1,346,234	1,339,189	1,333,668	16,373,774
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,389,708	1,394,875	1,391,547	1,390,635	1,364,464	1,363,309	1,357,836	1,353,325	1,348,984	1,346,234	1,339,189	1,333,668	16,373,774

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Applicable depreciation rate or rates
(F) Portions of 1287 have 7-year amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

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ECRC 2011 Est/Act True-UP
Exhibit RWD-2, Page 26 of 39

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: SPCC Compliance
P.E. 1272 & 1404
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	929,679	929,679	929,679	929,679	929,679	929,679	929,679	929,679	929,679	929,679	929,679	929,679	929,679	
3	Less: Accumulated Depreciation (C)	(122,100)	(124,810)	(127,520)	(130,230)	(132,940)	(135,650)	(138,360)	(141,070)	(143,780)	(146,490)	(149,200)	(151,910)	(154,620)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	807,579	804,869	802,159	799,449	796,739	794,029	791,319	788,609	785,899	783,189	780,479	777,769	775,059	
6	Average Net Investment		806,224	803,514	800,804	798,094	795,384	792,674	789,964	787,254	784,544	781,834	779,124	776,414	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		5,923	5,903	5,884	5,863	5,843	5,824	5,804	5,784	5,764	5,744	5,724	5,704	69,764
	b Debt Component (Line 6 x Debt Component x 1/12)		1,683	1,677	1,671	1,666	1,660	1,654	1,649	1,643	1,637	1,632	1,626	1,620	19,818
8	Investment Expenses														
	a Depreciation (E)		2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,710	32,520
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Annual NOx Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		10,316	10,290	10,265	10,239	10,213	10,188	10,163	10,137	10,111	10,086	10,060	10,034	122,102
	a Recoverable Costs Allocated to Energy		794	792	790	788	786	784	782	780	778	776	774	772	9,396
	b Recoverable Costs Allocated to Demand		9,522	9,498	9,475	9,451	9,427	9,404	9,381	9,357	9,333	9,310	9,286	9,262	112,706
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		765	767	765	765	761	761	758	755	753	751	748	745	9,094
13	Retail Demand-Related Recoverable Costs (I)		9,184	9,160	9,138	9,115	9,092	9,070	9,048	9,024	9,001	8,979	8,956	8,933	108,700
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		9,949	9,927	9,903	9,880	9,853	9,831	9,806	9,779	9,754	9,730	9,704	9,678	117,794

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist, $919,836; Smith $9,843. Ending Balances: Crist, $919,836; Smith $9,843.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Crist 3.5%; Smith 3.3% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

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ECRC 2011 Est/Act True-UP
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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Common FTIR Monitor
P.E. 1297
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	
3	Less: Accumulated Depreciation (C)	(14,120)	(14,303)	(14,486)	(14,669)	(14,852)	(15,035)	(15,218)	(15,401)	(15,584)	(15,767)	(15,950)	(16,133)	(16,316)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	48,750	48,567	48,384	48,201	48,018	47,835	47,652	47,469	47,286	47,103	46,920	46,737	46,554	
6	Average Net Investment		48,659	48,476	48,293	48,110	47,927	47,744	47,561	47,378	47,195	47,012	46,829	46,646	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		357	356	355	353	352	351	349	348	347	345	344	343	4,200
	b Debt Component (Line 6 x Debt Component x 1/12)		102	101	101	100	100	100	99	99	98	98	98	97	1,193
8	Investment Expenses														
	a Depreciation (E)		183	183	183	183	183	183	183	183	183	183	183	183	2,196
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Annual NOx Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		642	640	639	636	635	634	631	630	628	626	625	623	7,589
	a Recoverable Costs Allocated to Energy		642	640	639	636	635	634	631	630	628	626	625	623	7,589
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		618	620	619	618	615	615	611	610	608	606	604	601	7,345
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		618	620	619	618	615	615	611	610	608	606	604	601	7,345

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Docket No. 110007-EI
ECRC 2011 Est/Act True-UP
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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Precipitator Upgrades for CAM Compliance
P.E. 1175, 1191, 1305, 1461, 1462
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	
3	Less: Accumulated Depreciation (C)	(3,307,193)	(3,391,674)	(3,476,155)	(3,560,636)	(3,645,117)	(3,729,598)	(3,814,079)	(3,898,560)	(3,983,041)	(4,067,522)	(4,152,003)	(4,236,484)	(4,320,965)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	26,532,485	26,448,004	26,363,523	26,279,042	26,194,561	26,110,080	26,025,599	25,941,118	25,856,637	25,772,156	25,687,675	25,603,194	25,518,713	
6	Average Net Investment		26,490,245	26,405,764	26,321,283	26,236,802	26,152,321	26,067,840	25,983,359	25,898,878	25,814,397	25,729,916	25,645,435	25,560,954	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		194,624	194,003	193,381	192,763	192,142	191,521	190,900	190,279	189,658	189,038	188,417	187,796	2,294,522
	b Debt Component (Line 6 x Debt Component x 1/12)		55,285	55,109	54,933	54,756	54,580	54,404	54,227	54,051	53,875	53,698	53,522	53,346	651,786
8	Investment Expenses														
	a Depreciation (E)		84,481	84,481	84,481	84,481	84,481	84,481	84,481	84,481	84,481	84,481	84,481	84,481	1,013,772
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Annual NOx Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		334,390	333,593	332,795	332,000	331,203	330,406	329,608	328,811	328,014	327,217	326,420	325,623	3,960,080
	a Recoverable Costs Allocated to Energy		334,390	333,593	332,795	332,000	331,203	330,406	329,608	328,811	328,014	327,217	326,420	325,623	3,960,080
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		322,017	323,010	322,247	322,394	320,801	320,581	319,325	318,335	317,395	316,831	315,255	314,037	3,832,228
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		322,017	323,010	322,247	322,394	320,801	320,581	319,325	318,335	317,395	316,831	315,255	314,037	3,832,228

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist $13,997,696; Smith $15,715,201; Scholz $126,781. Ending Balances: Crist, $13,997,696; Smith $15,715,201; Scholz $126,781.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Crist 3.5%; Smith 3.3%; Scholz 4.1% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Plant Groundwater Investigation
P.E. 1218 & 1361
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	0	0	0	0	0	0	0	0	0	0	0	0	0	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 6 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Annual NOx Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist $0; Scholz $0. Ending Balances: Crist. $0; Scholz $0.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Crist 3.5% annually; Scholz 4.1% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Plant Crist Water Conservation Project
P.E.'s 1178, 1227, 1298
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
a	Expenditures/Additions		3,044	34,656	52,896	112,822	111,072	31,256	30,000	10,000	70,000	140,000	150,000	70,509	
b	Clearings to Plant		3,044	34,656	52,896	112,822	111,072	31,256	30,000	10,000	20,000	90,000	100,000	220,509	
c	Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
d	Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
e	Salvage		23,393	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	19,041,725	19,044,769	19,079,425	19,132,321	19,245,143	19,356,215	19,387,471	19,417,471	19,427,471	19,447,471	19,537,471	19,637,471	19,857,980	
3	Less: Accumulated Depreciation (C)	(496,666)	(575,604)	(631,158)	(686,813)	(742,622)	(798,760)	(855,222)	(911,775)	(968,416)	(1,025,086)	(1,081,814)	(1,138,805)	(1,196,088)	
4	CWIP - Non Interest Bearing (J)	0	0	0	0	0	0	0	0	0	50,000	100,000	150,000	0	
5	Net Investment (Lines 2 + 3 + 4)	18,545,059	18,469,165	18,448,267	18,445,508	18,502,521	18,557,455	18,532,249	18,505,696	18,459,055	18,472,385	18,555,657	18,648,666	18,661,892	
6	Average Net Investment		18,507,112	18,458,716	18,446,888	18,474,015	18,529,988	18,544,852	18,518,973	18,482,376	18,465,720	18,514,021	18,602,162	18,655,279	
7	Return on Average Net Investment														
a	Equity Component (Line 6 x Equity Component x 1/12) (D)		135,972	135,616	135,529	135,729	136,140	136,249	136,059	135,790	135,668	136,023	136,670	137,060	1,632,505
b	Debt Component (Line 6 x Debt Component x 1/12)		38,624	38,523	38,499	38,555	38,672	38,703	38,649	38,573	38,538	38,639	38,823	38,934	463,732
8	Investment Expenses														
a	Depreciation (E)		55,545	55,554	55,655	55,809	56,138	56,462	56,553	56,641	56,670	56,728	56,991	57,283	676,029
b	Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
c	Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
d	Annual NOx Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
e	Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		230,141	229,693	229,683	230,093	230,950	231,414	231,261	231,004	230,876	231,390	232,484	233,277	2,772,266
a	Recoverable Costs Allocated to Energy		17,703	17,669	17,668	17,699	17,765	17,801	17,789	17,770	17,760	17,799	17,883	17,944	213,250
b	Recoverable Costs Allocated to Demand		212,438	212,024	212,015	212,394	213,185	213,613	213,472	213,234	213,116	213,591	214,601	215,333	2,559,016
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		17,048	17,108	17,108	17,187	17,207	17,272	17,234	17,204	17,185	17,234	17,271	17,306	206,364
13	Retail Demand-Related Recoverable Costs (I)		204,888	204,488	204,480	204,845	205,608	206,021	205,885	205,655	205,541	206,000	206,974	207,680	2,468,065
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		221,936	221,596	221,588	222,032	222,815	223,293	223,119	222,859	222,726	223,234	224,245	224,986	2,674,429

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) Applicable depreciation rate or rates
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11
(J) Revised to exclude $73,956 that was incorrectly included in CWIP in December 2008 for PE 1298.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: Plant NPDES Permit Compliance Projects
P.E. 1204 & 1299
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		607	1	2	(5)	0	0	0	0	75,000	75,000	50,000	0	
	b Clearings to Plant		607	1	2	(5)	0	0	0	0	0	0	0	200,000	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	6,017,436	6,018,043	6,018,044	6,018,046	6,018,041	6,018,041	6,018,041	6,018,041	6,018,041	6,018,041	6,018,041	6,018,041	6,218,041	
3	Less: Accumulated Depreciation (C)	(898,358)	(915,911)	(933,466)	(951,021)	(968,576)	(986,131)	(1,003,686)	(1,021,241)	(1,038,796)	(1,056,351)	(1,073,906)	(1,091,461)	(1,109,016)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	75,000	150,000	200,000	0	
5	Net Investment (Lines 2 + 3 + 4)	5,119,078	5,102,132	5,084,578	5,067,025	5,049,465	5,031,910	5,014,355	4,996,800	4,979,245	5,036,690	5,094,135	5,126,580	5,109,025	
6	Average Net Investment		5,110,605	5,093,355	5,075,802	5,058,245	5,040,688	5,023,133	5,005,578	4,988,023	5,007,968	5,065,413	5,110,358	5,117,803	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		37,549	37,421	37,292	37,162	37,034	36,905	36,776	36,647	36,794	37,216	37,546	37,600	445,942
	b Debt Component (Line 6 x Debt Component x 1/12)		10,666	10,630	10,593	10,557	10,520	10,483	10,447	10,410	10,452	10,572	10,665	10,681	126,676
8	Investment Expenses														
	a Depreciation (E)		17,553	17,555	17,555	17,555	17,555	17,555	17,555	17,555	17,555	17,555	17,555	17,555	210,658
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Annual NOx Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		65,768	65,606	65,440	65,274	65,109	64,943	64,778	64,612	64,801	65,343	65,766	65,836	783,276
	a Recoverable Costs Allocated to Energy		5,059	5,047	5,034	5,021	5,008	4,996	4,983	4,970	4,985	5,026	5,059	5,064	60,252
	b Recoverable Costs Allocated to Demand		60,709	60,559	60,406	60,253	60,101	59,947	59,795	59,642	59,816	60,317	60,707	60,772	723,024
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		4,872	4,887	4,874	4,876	4,851	4,847	4,828	4,812	4,824	4,866	4,886	4,884	58,307
13	Retail Demand-Related Recoverable Costs (I)		58,551	58,407	58,259	58,111	57,965	57,816	57,670	57,522	57,690	58,173	58,549	58,612	697,325
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		63,423	63,294	63,133	62,987	62,816	62,663	62,498	62,334	62,514	63,039	63,435	63,496	755,632

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s)
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%
(E) 3.5% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR/CAVR Compliance
P.E.s 1034, 1035, 1036, 1037, 1222, 1233, 1279, 1362, 1468, 1469, 1512, 1513, 1646, 1647, 1684, 1810, 1824, & 1826
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		97,363	57,400	170,944	51,720	1,294,602	78,722	8,231,240	3,214	3,214	3,214	3,214	0	
	b Clearings to Plant		53,693	56,426	201,558	349,712	1,294,602	78,722	8,231,240	3,214	3,214	3,214	3,214	0	
	c Retirements		57,921	0	84,294	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		6,927	0	802,127	85,134	1,212	3,298	(891,774)	0	0	0	0	0	
	e Salvage		7,798	0	0	0	40,360	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	627,568,922	627,564,694	627,621,120	627,738,384	628,088,096	629,382,698	629,461,420	637,692,660	637,695,874	637,699,088	637,702,302	637,705,516	637,705,516	
3	Less: Accumulated Depreciation (C)	(29,377,564)	(31,461,111)	(33,610,483)	(34,869,205)	(36,929,556)	(39,115,209)	(41,262,192)	(44,304,477)	(46,478,998)	(48,653,529)	(50,828,069)	(53,002,619)	(55,177,178)	
4	CWIP - Non Interest Bearing	283,963	327,633	328,607	297,993	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	598,475,321	596,431,216	594,339,244	593,167,172	591,158,540	590,267,489	588,199,228	593,388,183	591,216,876	589,045,559	586,874,233	584,702,897	582,528,338	
6	Average Net Investment		597,453,269	595,385,230	593,753,208	592,162,856	590,713,015	589,233,359	590,793,706	592,302,530	590,131,218	587,959,896	585,788,565	583,615,618	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		4,389,488	4,374,295	4,362,304	4,350,621	4,339,970	4,329,099	4,340,561	4,351,647	4,335,694	4,319,741	4,303,789	4,287,824	52,085,033
	b Debt Component (Line 6 x Debt Component x 1/12)		1,246,885	1,242,569	1,239,163	1,235,844	1,232,818	1,229,730	1,232,986	1,236,135	1,231,604	1,227,072	1,222,541	1,218,006	14,795,353
8	Investment Expenses														
	a Depreciation (E)		1,817,604	1,817,591	1,817,756	1,818,098	1,819,118	1,822,894	1,823,124	1,847,134	1,847,144	1,847,153	1,847,163	1,847,172	21,971,951
	b Amortization (F)		12,490	12,490	12,490	12,490	12,490	12,490	12,490	12,490	12,490	12,490	12,490	12,490	149,880
	c Dismantlement		314,897	314,897	314,897	314,897	314,897	314,897	314,897	314,897	314,897	314,897	314,897	314,897	3,778,764
	d Annual NOx Allowance Expense		18,162	18,162	18,162	18,162	18,162	18,162	18,162	18,162	18,162	18,162	18,162	18,162	217,944
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		7,799,526	7,780,004	7,764,772	7,750,112	7,737,455	7,727,272	7,742,220	7,780,465	7,759,991	7,739,515	7,719,042	7,698,551	92,998,925
	a Recoverable Costs Allocated to Energy		7,799,526	7,780,004	7,764,772	7,750,112	7,737,455	7,727,272	7,742,220	7,780,465	7,759,991	7,739,515	7,719,042	7,698,551	92,998,925
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		7,510,928	7,533,185	7,518,674	7,525,882	7,494,444	7,497,485	7,500,686	7,532,567	7,508,781	7,493,850	7,455,007	7,424,634	89,996,123
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		7,510,928	7,533,185	7,518,674	7,525,882	7,494,444	7,497,485	7,500,686	7,532,567	7,508,781	7,493,850	7,455,007	7,424,634	89,996,123

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Beginning Balances: Crist $607,220,634; Smith $12,931,385; Daniel $6,772,682, Scholz $644,221. Ending Balances: Crist $617,356,712; Smith $12,931,385; Daniel $6,773,199, Scholz $644,221.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Crist: 3.5%, Plant Smith Steam 3.3%, Smith CT 3.6%, Daniel 2.8%, Scholz 4.1%. Portion of PE 1222 is transmission 2.0%, 2.3%, 3.5%, and 3.6%
(F) Portion of PE 1222 applicable 7 year amortization period beginning in 2008.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11
(J) Project #1222 qualifies for AFUDC treatment. As portions of the project are moved to P-I-S, they are included in the ECRC.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Capital Investments, Depreciation and Taxes
For Project: General Water Quality
P.E.1280
(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	
3	Less: Accumulated Depreciation (C)	(15,866)	(16,400)	(16,934)	(17,468)	(18,002)	(18,536)	(19,070)	(19,604)	(20,138)	(20,672)	(21,206)	(21,740)	(22,274)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	16,155	15,621	15,087	14,553	14,019	13,485	12,951	12,417	11,883	11,349	10,815	10,281	9,747	
6	Average Net Investment		15,888	15,354	14,820	14,286	13,752	13,218	12,684	12,150	11,616	11,082	10,548	10,014	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		117	113	109	105	101	97	93	89	85	81	77	74	1,141
	b Debt Component (Line 6 x Debt Component x 1/12)		33	32	31	30	29	28	26	25	24	23	22	21	324
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		534	534	534	534	534	534	534	534	534	534	534	534	6,408
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Annual NOx Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		684	679	674	669	664	659	653	648	643	638	633	629	7,873
	a Recoverable Costs Allocated to Energy		53	52	52	51	51	51	50	50	49	49	49	48	605
	b Recoverable Costs Allocated to Demand		631	627	622	618	613	608	603	598	594	589	584	581	7,268
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		51	50	50	50	49	49	48	48	47	47	47	46	582
13	Retail Demand-Related Recoverable Costs (I)		609	605	600	596	591	586	582	577	573	568	563	560	7,010
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		660	655	650	646	640	635	630	625	620	615	610	606	7,592

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Applicable depreciation rate or rates.
(F) 5 year amortization beginning 2008.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Working Capital, Mercury Allowance Expenses
For Project: Mercury Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	0	0	0	0	0	0	0	0	0	0	0	0	0	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	Average Net Working Capital Balance		0	0	0	0	0	0	0	0	0	0	0	0	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 4 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
6	Total Return Component (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
7	Expenses														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Annual NOx Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Net Expenses (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 6 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (B)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(A) Equity Component has been grossed up for taxes. The approved ROE is 12%.
(B) Line 9a x Line 10 x 1.0007 line loss multiplier
(C) Line 9b x Line 11
(D) Line 6 is reported on Schedule 6E and 7E
(E) Line 8 is reported on Schedule 4E and 5E

Docket No. 110007-EI
ECRC 2011 Est/Act True-UP
Exhibit RWD-2, Page 35 of 39

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Working Capital, Annual NOx Expenses
For Project: Annual NOx Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	4,533,754	4,067,923	3,901,539	3,737,874	3,573,662	3,283,631	2,946,498	2,606,304	2,256,291	1,956,115	1,678,772	1,463,008	1,268,170	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	4,533,754	4,067,923	3,901,539	3,737,874	3,573,662	3,283,631	2,946,498	2,606,304	2,256,291	1,956,115	1,678,772	1,463,008	1,268,170	
4	Average Net Working Capital Balance		4,300,839	3,984,731	3,819,707	3,655,768	3,428,647	3,115,065	2,776,401	2,431,298	2,106,203	1,817,444	1,570,890	1,365,589	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		31,598	29,276	28,063	26,859	25,190	22,886	20,398	17,863	15,474	13,353	11,541	10,033	252,534
	b Debt Component (Line 4 x Debt Component x 1/12)		8,976	8,316	7,972	7,630	7,156	6,501	5,794	5,074	4,396	3,793	3,278	2,850	71,736
6	Total Return Component (D)		40,574	37,592	36,035	34,489	32,346	29,387	26,192	22,937	19,870	17,146	14,819	12,883	324,270
7	Expenses														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Annual NOx Allowance Expense		465,831	166,384	163,665	164,212	290,031	337,133	340,194	350,013	300,176	277,343	215,764	194,838	3,265,584
8	Net Expenses (E)		465,831	166,384	163,665	164,212	290,031	337,133	340,194	350,013	300,176	277,343	215,764	194,838	3,265,584
9	Total System Recoverable Expenses (Lines 6 + 8)		506,405	203,976	199,700	198,701	322,377	366,520	366,386	372,950	320,046	294,489	230,583	207,721	3,589,854
	a Recoverable Costs Allocated to Energy		506,405	203,976	199,700	198,701	322,377	366,520	366,386	372,950	320,046	294,489	230,583	207,721	3,589,854
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (B)		487,667	197,505	193,371	192,952	312,252	355,621	354,956	361,067	309,685	285,141	222,696	200,330	3,473,243
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		487,667	197,505	193,371	192,952	312,252	355,621	354,956	361,067	309,685	285,141	222,696	200,330	3,473,243

Notes:
(A) Equity Component has been grossed up for taxes. The approved ROE is 12%
(B) Line 9a x Line 10 x 1.0007 line loss multiplier
(C) Line 9b x Line 11
(D) Line 6 is reported on Schedule 6E and 7E
(E) Line 8 is reported on Schedule 4E and 5E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Working Capital, Seasonal NOx Expenses
For Project: Seasonal NOx Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	11,253	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	4,600	4,600	4,600	4,600	4,600	3,876	2,738	1,574	376	0	0	0	0	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	4,600	4,600	4,600	4,600	4,600	3,876	2,738	1,574	376	0	0	0	0	
4	Average Net Working Capital Balance		4,600	4,600	4,600	4,600	4,238	3,307	2,156	975	188	0	0	0	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		34	34	34	34	31	24	16	7	1	0	0	0	215
	b Debt Component (Line 4 x Debt Component x 1/12)		10	10	10	10	9	7	4	2	0	0	0	0	62
6	Total Return Component (D)		44	44	44	44	40	31	20	9	1	0	0	0	277
7	Expenses														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Annual NOx Allowance Expense		0	0	0	0	724	1,138	1,164	1,198	11,629	0	0	0	15,853
8	Net Expenses (E)		0	0	0	0	724	1,138	1,164	1,198	11,629	0	0	0	15,853
9	Total System Recoverable Expenses (Lines 6 + 8)		44	44	44	44	764	1,169	1,184	1,207	11,630	0	0	0	16,130
	a Recoverable Costs Allocated to Energy		44	44	44	44	764	1,169	1,184	1,207	11,630	0	0	0	16,130
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (B)		42	43	43	43	740	1,134	1,147	1,168	11,253	0	0	0	15,613
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		42	43	43	43	740	1,134	1,147	1,168	11,253	0	0	0	15,613

Notes:
(A) Equity Component has been grossed up for taxes. The approved ROE is 12%
(B) Line 9a x Line 10 x 1.0007 line loss multiplier
(C) Line 9b x Line 11
(D) Line 6 is reported on Schedule 6E and 7E
(E) Line 8 is reported on Schedule 4E and 5E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Current Period Estimated True-Up Amount
January 2011 - December 2011

Return on Working Capital, SO2 Expenses
For Project: SO2 Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Actual January	Actual February	Actual March	Actual April	Actual May	Actual June	Estimated July	Estimated August	Estimated September	Estimated October	Estimated November	Estimated December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	2,643	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	9,765,386	9,677,874	9,610,967	9,551,173	9,466,550	9,339,733	9,220,313	9,057,083	8,887,550	8,738,320	8,597,713	8,499,199	8,410,149	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	(910,417)	(900,944)	(891,471)	(884,392)	(874,670)	(864,948)	(855,226)	(845,504)	(835,782)	(826,060)	(816,338)	(806,616)	(796,894)	
3	Total Working Capital Balance	8,854,969	8,776,930	8,719,496	8,666,781	8,591,880	8,474,785	8,365,087	8,211,579	8,051,768	7,912,260	7,781,375	7,692,583	7,613,255	
4	Average Net Working Capital Balance		8,815,950	8,748,213	8,693,139	8,629,331	8,533,333	8,419,936	8,288,333	8,131,674	7,982,014	7,846,818	7,736,979	7,652,919	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		64,771	64,273	63,868	63,400	62,694	61,861	60,894	59,743	58,644	57,651	56,844	56,226	730,869
	b Debt Component (Line 4 x Debt Component x 1/12)		18,399	18,258	18,143	18,009	17,809	17,572	17,298	16,971	16,658	16,376	16,147	15,972	207,612
6	Total Return Component (D)		83,170	82,531	82,011	81,409	80,503	79,433	78,192	76,714	75,302	74,027	72,991	72,198	938,481
7	Expenses														
	a Gains		(9,473)	(9,473)	(9,722)	(9,722)	(9,722)	(9,722)	(9,722)	(9,722)	(9,722)	(9,722)	(9,722)	(9,722)	(116,166)
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Annual NOx Allowance Expense		87,512	66,907	59,794	84,623	126,817	119,420	163,230	169,533	149,230	140,607	98,514	89,050	1,355,237
8	Net Expenses (E)		78,039	57,434	50,072	74,901	117,095	109,698	153,508	159,811	139,508	130,885	88,792	79,328	1,239,071
9	Total System Recoverable Expenses (Lines 6 + 8)		161,209	139,965	132,083	156,310	197,598	189,131	231,700	236,525	214,810	204,912	161,783	151,526	2,177,552
	a Recoverable Costs Allocated to Energy		161,209	139,965	132,083	156,310	197,598	189,131	231,700	236,525	214,810	204,912	161,783	151,526	2,177,552
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9623244	0.9675979	0.9676285	0.9703882	0.9679154	0.9695842	0.9681253	0.9674612	0.9669507	0.9675810	0.9651187	0.9637450	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (B)		155,244	135,525	127,897	151,788	191,392	183,507	224,472	228,989	207,856	198,408	156,249	146,135	2,107,462
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		155,244	135,525	127,897	151,788	191,392	183,507	224,472	228,989	207,856	198,408	156,249	146,135	2,107,462

Notes:
(A) Equity Component has been grossed up for taxes. The approved ROE is 12%
(B) Line 9a x Line 10 x 1.0007 line loss multiplier
(C) Line 9b x Line 11
(D) Line 6 is reported on Schedule 6E and 7E
(E) Line 8 is reported on Schedule 4E and 5E

Docket No. 110007-EI
ECRC 2011 Est/Act True-UP
Exhibit RWD-2, Page 38 of 39

Schedule 9E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated/Actual True-Up Amount
January 2011 - December 2011
FPSC Capital Structure and Cost Rates

Line	Capital Component	(1) Jurisdictional Rate Base Test Year ($000's)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %	(5) Revenue Requirement Rate %	(6) Monthly Revenue Requirement Rate %
1	Bonds	423,185	35.2733	6.44	2.2716	2.2716	
2	Short-Term Debt	33,714	2.8101	4.61	0.1295	0.1295	
3	Preferred Stock	98,680	8.2252	4.93	0.4055	0.6602	
4	Common Stock	492,186	41.0247	12.00	4.9230	8.0147	
5	Customer Deposits	13,249	1.1043	5.98	0.0660	0.0660	
6	Deferred Taxes	122,133	10.1801				
7	Investment Tax Credit	16,584	1.3823	8.99	0.1243	0.1790	
8	Total	1,199,731	100.0000		7.9199	11.3210	0.9434
	ITC Component:						
9	Debt	423,185	41.7321	6.44	2.6875	0.0371	
10	Equity-Preferred	98,680	9.7313	4.93	0.4798	0.0108	
11	-Common	492,186	48.5366	12.00	5.8244	0.1311	
12		1,014,051	100.0000		8.9917	0.1790	
	Breakdown of Revenue Requirement Rate of Return between Debt and Equity:						
13	Total Debt Component (Lines 1, 2, 5, and 9)					2.5042	0.2087
14	Total Equity Component (Lines 3, 4, 10, and 11)					8.8168	0.7347
15	Total Revenue Requirement Rate of Return					11.3210	0.9434

Column:
(1) Capital Structure Approved by FPSC on June 10, 2002 in Docket No. 010949-EI
(2) Column (1) / Total Column (1)
(3) Cost Rates Approved by FPSC on June 10, 2002 in Docket No. 010949-EI
(4) Column (2) x Column (3)
(5) For equity components: Column (4) / (1-.38575); 38.575% = effective income tax rate
For debt components: Column (4)
(6) Column (5) / 12

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: **Environmental Cost Recovery Clause**))) Docket No. **110007-EI**

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing has been furnished this 29th day of July, 2011, by U.S. mail to the following:

Martha Carter Brown, Esq.
Senior Counsel
FL Public Service Comm.
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850
mbrown@psc.state.fl.us

Vicki Gordan Kaufman
John C. Moyle
FIPUG
118 N. Gadsden Street
Tallahassee, FL 32301
vkaufman@kagmlaw.com
jmoyle@kagmlaw.com

Paula K. Brown
Tampa Electric Company
P. O. Box 111
Tampa, FL 33601
Regdept@tecoenergy.com

John T. Butler, Esq.
Attorney for Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420
John.Butler@fpl.com

James D. Beasley, Esq.
J. Jeffry Wahlen
Attorneys for Tampa Electric Co.
Ausley & McMullen
P. O. Box 391
Tallahassee, FL 32302
jbeasley@ausley.com

Paul Lewis, Jr.
Progress Energy Florida, Inc.
106 E. College Ave., Ste. 800
Tallahassee, FL 32301
paul.lewisjr@pgnmail.com

Karen S. White, Staff Attorney
c/o AFCESA-ULFSC
139 Barnes Drive, Suite 1
Tyndall AFB, FL 32403-5319
Phone: 850-283-6348
FAX: 850-283-6219
Email: karen.white@tyndall.af.mil

Kenneth Hoffman
Florida Power & Light Company
215 South Monroe Street, Suite 810
Tallahassee, FL 32301-1858
Ken.Hoffman@fpl.com

Gary V. Perko, Esq.
Hopping Green & Sams
P. O. Box 6526
Tallahassee, FL 32314
gperko@hgslaw.com

J.R. Kelly
P. Christensen
C. Rehwinkel
Associate Public Counsel
Office of Public Counsel
111 W. Madison St., Rm. 812
Tallahassee, FL 32399-1400
christensen.patty@leg.state.fl.us
rehwinkel.charles@leg.state.fl.us
kelly.jr@leg.state.fl.us

John T. Burnett, Esq.
Dianne M. Triplett
Progress Energy Service Co.
P. O. Box 14042
St. Petersburg, FL 33733-4042
john.burnett@pgnmail.com

JEFFREY A. STONE
Florida Bar No. 325953
RUSSELL A. BADDERS
Florida Bar No. 007455
STEVEN GRIFFIN
Florida Bar No. 0627569
BEGGS & LANE
P. O. Box 12950
Pensacola FL 32591-2950
(850) 432-2451
Attorneys for Gulf Power Company

Schedule 1P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to be Recovered

For the Projected Period
January 2012 - December 2012

Line No.		Energy ($)	Demand ($)	Total ($)
1	Total Jurisdictional Rev. Req. for the projected period			
	a Projected O & M Activities (Schedule 2P, Lines 7, 8 & 9)	21,533,397	3,682,074	25,215,471
	b Projected Capital Projects (Schedule 3P, Lines 7, 8 & 9)	137,644,370	6,243,986	143,888,356
	c Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b)	159,177,767	9,926,060	169,103,827
2	True-Up for Estimated Over/(Under) Recovery for the period January 2011 - December 2011 (Schedule 1E, Line 3)	13,494,673	885,840	14,380,513
3	Final True-Up for the period January 2010 - December 2010 (Schedule 1A, Line 3)	815,244	46,081	861,325
4	Total Jurisdictional Amount to be Recovered/(Refunded) in the projection period January 2012 - December 2012 (Line 1c - Line 2 - Line 3)	144,867,850	8,994,139	153,861,989
5	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier)	144,972,155	9,000,615	153,972,770

Notes:

Allocation to energy and demand in each period are in proportion to the respective period split of costs indicated on Lines 7 & 8 of Schedules 5E & 7E and 5A & 7A.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI EXHIBIT 37
PARTY GULF POWER COMPANY (DIRECT)
DESCRIPTION R. W. DODD (RWD-3)
DATE 11/01/11

Schedule 2P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

O & M Activities
(in Dollars)

Line		Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period 12-Month	Method of Classification Demand	Method of Classification Energy
1	Description of O & M Activities															
	.1 Sulfur	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.2 Air Emission Fees	-	701,000	-	-	-	-	-	-	-	-	124,374	-	825,374	0	825,374
	.3 Title V	8,313	9,313	9,478	10,328	8,528	13,743	9,028	9,828	10,278	10,028	12,793	10,278	121,936	0	121,936
	.4 Asbestos Fees	-	-	-	-	-	500	-	-	-	900	-	-	1,400	1,400	0
	.5 Emission Monitoring	59,469	45,469	44,992	54,992	59,992	58,279	46,992	64,992	50,992	47,492	57,779	49,003	640,443	0	640,443
	.6 General Water Quality	24,147	44,147	68,344	61,344	93,344	68,067	80,294	102,794	100,694	87,325	103,922	63,644	898,066	898,066	0
	.7 Groundwater Contamination Investigation	117,550	117,550	119,573	272,923	271,923	141,281	122,073	121,240	271,423	271,923	139,173	117,236	2,083,868	2,083,868	0
	.8 State NPDES Administration	-	-	-	-	-	-	-	-	-	-	-	34,500	34,500	34,500	0
	.9 Lead and Copper Rule	1,373	1,373	1,373	1,373	1,373	1,373	1,373	1,373	1,373	1,373	1,373	1,377	16,480	16,480	0
	.10 Env Auditing/Assessment	-	-	-	-	-	-	-	3,500	3,500	-	-	-	7,000	7,000	0
	.11 General Solid & Hazardous Waste	31,014	33,083	33,992	36,492	33,424	42,536	35,992	43,247	44,748	43,248	43,037	37,181	457,994	457,994	0
	.12 Above Ground Storage Tanks	5,508	5,508	23,922	20,722	22,522	24,183	3,122	4,022	25,822	3,022	783	23,321	162,457	162,457	0
	.13 Low NOx	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.14 Ash Pond Diversion Curtains	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.15 Mercury Emissions	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.16 Sodium Injection	11,333	2,000	11,333	2,000	11,333	2,000	10,333	1,000	10,333	1,000	10,335	1,000	74,000	0	74,000
	.17 Gulf Coast Ozone Study	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.18 SPCC Substation Project	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.19 FDEP NOx Reduction Agreement	164,913	152,294	146,145	147,234	149,059	150,941	143,682	144,682	144,682	92,240	92,499	144,679	1,673,050	0	1,673,050
	.20 CAIR/CAMR/CAVR Compliance Program	1,221,652	1,302,610	1,209,175	1,221,675	1,562,877	1,606,944	1,650,870	1,688,129	1,577,134	1,153,863	1,039,894	1,150,093	16,384,916	0	16,384,916
	.21 MACT ICR	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.22 Crist Water Conservation	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	13,000	156,000	156,000	0
	.23 Mercury Allowances	-	-	-	-	-	-	-	-	-	-	-	-	0	0	0
	.24 Annual NOx Allowances	5,954	5,954	5,954	5,954	5,954	8,215	20,440	21,027	6,357	5,954	5,954	5,954	103,671	0	103,671
	.25 Seasonal NOx Allowances	-	-	-	-	-	-	-	516,439	1,202,586	-	-	-	1,719,025	0	1,719,025
	.26 SO2 Allowances	32,454	43,280	61,406	65,283	65,143	68,660	83,187	86,460	65,651	59,834	50,607	35,033	716,998	0	716,998
2	Total of O & M Activities	1,696,680	2,476,581	1,748,687	1,913,320	2,298,472	2,199,722	2,220,386	2,821,733	3,528,573	1,791,202	1,695,523	1,686,299	26,077,178	3,817,765	22,259,413
3	Recoverable Costs Allocated to Energy	1,504,088	2,261,920	1,488,483	1,507,466	1,862,886	1,908,782	1,964,532	2,532,557	3,068,013	1,370,411	1,394,235	1,396,040	22,259,413		
4	Recoverable Costs Allocated to Demand	192,592	214,661	260,204	405,854	435,586	290,940	255,854	289,176	460,560	420,791	301,288	290,259	3,817,765		
5	Retail Energy Jurisdictional Factor	0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848			
6	Retail Demand Jurisdictional Factor	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582			
7	Jurisdictional Energy Recoverable Costs (A)	1,452,794	2,183,878	1,439,546	1,458,517	1,804,732	1,849,956	1,903,229	2,451,983	2,968,752	1,326,938	1,346,648	1,346,424	21,533,397		
8	Jurisdictional Demand Recoverable Costs (B)	185,747	207,032	250,956	391,429	420,104	280,599	246,760	278,898	444,191	405,835	290,580	279,943	3,682,074		
9	Total Jurisdictional Recoverable Costs for O & M Activities (Lines 7 + 8)	1,638,541	2,390,910	1,690,502	1,849,946	2,224,836	2,130,555	2,149,989	2,730,881	3,412,943	1,732,773	1,637,228	1,626,367	25,215,471		

Notes:
(A) Line 3 x Line 5 x line loss multiplier
(B) Line 4 x Line 6

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2012 Projection Filing
Exhibit RWD-3, Page 2 of 90

Schedule 3P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Capital Investment Projects - Recoverable Costs
(in Dollars)

Line		Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period 12-Month	Method of Classification Demand	Method of Classification Energy
1	Description of Investment Projects (A)															
	1 Air Quality Assurance Testing	5,404	5,367	5,328	5,289	5,252	5,213	5,174	5,136	5,097	5,057	5,018	4,979	62,314	0	62,314
	2 Crist 5, 6 & 7 Precipitator Projects	272,549	338,345	442,113	516,164	529,601	512,255	617,126	615,825	614,523	613,222	611,920	610,854	6,294,497	0	6,294,497
	3 Crist 7 Flue Gas Conditioning	13,983	13,981	13,979	13,977	13,974	13,973	13,971	13,969	13,967	13,965	13,963	13,961	167,663	0	167,663
	4 Low NOx Burners, Crist 6 & 7	163,044	162,793	162,543	162,293	162,043	161,793	161,543	161,292	161,042	160,791	160,541	160,291	1,940,009	0	1,940,009
	5 CEMS - Plants Crist, Scholz, Smith, & Daniel	116,953	116,753	116,552	116,353	116,153	115,953	115,753	115,553	115,354	115,154	114,954	114,754	1,390,239	0	1,390,239
	6 Sub. Contam. Mobile Groundwater Treat. Sys	8,531	8,508	8,485	8,463	8,440	8,417	8,395	8,372	8,349	8,327	8,304	8,281	100,872	93,113	7,759
	.7 Raw Water Well Flowmeters - Plants Crist & Smith	2,157	2,150	2,144	2,138	2,131	2,125	2,117	2,111	2,104	2,098	2,091	2,085	25,451	23,495	1,956
	.8 Crist Cooling Tower Cell	4,889	4,887	4,885	4,884	4,883	4,880	4,879	4,878	4,876	4,874	4,873	4,871	58,559	54,054	4,505
	.9 Crist Dechlorination System	3,948	3,936	3,923	3,911	3,898	3,886	3,873	3,861	3,848	3,835	3,823	3,811	46,553	42,971	3,582
	.10 Crist Diesel Fuel Oil Remediation	532	531	529	527	525	523	522	519	518	516	514	512	6,268	5,785	483
	11 Crist Bulk Tanker Unload Sec Contain Struc	698	695	692	689	686	684	681	679	675	672	670	667	8,188	7,558	630
	12 Crist IWW Sampling System	406	405	404	401	400	399	396	395	394	392	390	388	4,770	4,404	366
	13 Sodium Injection System	3,876	3,866	3,855	3,844	3,834	3,823	3,813	3,802	3,791	3,781	3,771	3,759	45,815	0	45,815
	14 Smith Stormwater Collection System	20,694	20,622	20,550	20,478	20,405	20,333	20,261	20,189	20,117	20,045	19,973	19,901	243,568	224,832	18,736
	15 Smith Waste Water Treatment Facility	2,968	2,963	2,959	2,954	2,950	2,945	2,940	2,936	2,930	2,926	2,921	2,916	35,308	32,592	2,716
	.16 Daniel Ash Management Project	170,936	170,494	170,051	169,609	169,167	168,725	168,283	167,840	167,398	166,956	166,514	166,072	2,022,045	1,866,501	155,544
	.17 Smith Water Conservation	51,893	52,990	54,088	56,285	59,583	62,882	66,180	69,479	72,777	76,076	79,374	82,672	784,279	723,949	60,330
	.18 Underground Fuel Tank Replacement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.19 Crist FDEP Agreement for Ozone Attainment	1,379,115	1,375,368	1,371,621	1,369,447	1,367,744	1,364,044	1,361,888	1,359,731	1,357,899	1,356,076	1,355,509	1,354,620	16,373,062	0	16,373,062
	.20 SPCC Compliance	10,009	9,983	9,958	9,933	9,907	9,881	9,856	9,830	9,804	9,779	9,753	9,728	118,421	109,313	9,108
	.21 Crist Common FTIR Monitor	621	620	618	616	614	613	611	609	608	606	604	603	7,343	0	7,343
	.22 Precipitator Upgrades for CAM Compliance	324,826	324,029	323,232	322,435	321,638	320,841	320,045	319,247	318,450	317,653	316,856	316,059	3,845,311	0	3,845,311
	.23 Plant Groundwater Investigation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	24 Crist Water Conservation	233,709	233,163	232,616	232,069	231,523	230,976	230,431	229,884	229,337	228,791	228,244	227,698	2,768,441	2,555,486	212,955
	.25 Crist Condenser Tubes	66,251	66,080	65,909	65,738	65,566	65,395	65,224	65,054	64,882	64,711	64,540	64,369	783,719	723,433	60,286
	.26 CAIR/CAMR/CAVR Compliance	7,677,495	7,657,264	7,637,318	8,364,006	9,679,298	9,892,393	9,933,065	9,947,886	9,948,632	9,948,994	9,938,479	10,039,441	110,664,271	0	110,664,271
	.27 General Water Quality	624	619	614	608	603	598	593	588	583	578	573	569	7,150	6,600	550
	.28 Mercury Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	.29 Annual NOx Allowances	11,964	11,964	11,964	11,964	11,964	11,964	11,964	11,964	11,964	11,964	11,964	11,964	143,568	0	143,568
	.30 Seasonal NOx Allowances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	31 SO2 Allowances	71,586	71,229	70,735	70,138	69,523	68,891	68,175	67,375	66,657	66,065	65,545	65,140	821,059	0	821,059
2	Total Investment Projects - Recoverable Costs	10,619,661	10,659,605	10,737,665	11,535,213	12,862,305	13,054,405	13,197,759	13,209,004	13,206,576	13,203,904	13,191,681	13,290,965	148,768,743	6,474,086	142,294,657
3	Recoverable Costs Allocated to Energy	10,085,897	10,126,042	10,204,307	11,001,041	12,326,305	12,516,574	12,658,099	12,667,512	12,663,259	12,658,757	12,644,707	12,742,157	142,294,657		
4	Recoverable Costs Allocated to Demand	533,764	533,563	533,358	534,172	536,000	537,831	539,660	541,492	543,317	545,147	546,974	548,808	6,474,086		
5	Retail Energy Jurisdictional Factor	0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848			
6	Retail Demand Jurisdictional Factor	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582			
7	Jurisdictional Energy Recoverable Costs (B)	9,741,939	9,776,669	9,868,816	10,643,827	11,941,514	12,130,833	12,263,107	12,264,492	12,253,558	12,257,190	12,213,131	12,289,294	137,644,370		
8	Jurisdictional Demand Recoverable Costs (C)	514,793	514,599	514,401	515,187	516,950	518,716	520,480	522,246	524,007	525,771	527,534	529,302	6,243,986		
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	10,256,732	10,291,268	10,383,217	11,159,014	12,458,464	12,649,549	12,783,587	12,786,738	12,777,565	12,782,961	12,740,665	12,818,596	143,888,356		

Notes:

(A) Pages 1-27 of Schedule 8E, Line 9; Pages 28-31 of Schedule 8E, Line 6

(B) Line 3 x Line 5 x Line loss multiplier

(C) Line 4 x Line 6

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Air Quality Assurance Testing
P.E.s 1006 & 1244
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	350,812	
3	Less: Accumulated Depreciation (C)	(217,739)	(221,908)	(226,078)	(230,249)	(234,421)	(238,594)	(242,768)	(246,943)	(251,119)	(255,295)	(259,471)	(263,647)	(267,823)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	133,073	128,904	124,734	120,563	116,391	112,218	108,044	103,869	99,693	95,517	91,341	87,165	82,989	
6	Average Net Investment		130,989	126,819	122,649	118,477	114,305	110,131	105,957	101,781	97,605	93,429	89,253	85,077	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		962	932	901	870	840	809	778	748	717	686	656	625	9,524
	b Debt Component (Line 6 x Debt Component x 1/12)		273	265	256	247	239	230	221	212	204	195	186	178	2,706
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		4,169	4,170	4,171	4,172	4,173	4,174	4,175	4,176	4,176	4,176	4,176	4,176	50,084
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		5,404	5,367	5,328	5,289	5,252	5,213	5,174	5,136	5,097	5,057	5,018	4,979	62,314
	a Recoverable Costs Allocated to Energy		5,404	5,367	5,328	5,289	5,252	5,213	5,174	5,136	5,097	5,057	5,018	4,979	62,314
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		5,220	5,182	5,153	5,117	5,088	5,052	5,013	4,973	4,932	4,897	4,847	4,802	60,276
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		5,220	5,182	5,153	5,117	5,088	5,052	5,013	4,973	4,932	4,897	4,847	4,802	60,276

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Applicable depreciation rate or rates.
(F) PE 1244 7 year amorization; PE 1006 fully amortized
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 5, 6 & 7 Precipitator Projects
P.E.s 1038, 1119, 1216, 1243, 1249
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		5,000,000	6,500,000	10,500,000	2,750,000	200,000	50,000	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	36,146,453	0	0	0	0	0	0	
	c Retirements		0	0	0	0	6,216,000	0	0	0	0	0	0	0	
	d Cost of Removal		0	2,550,000	2,550,000	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	(50,000)	
2	Plant-in-Service/Depreciation Base (B)	13,909,529	13,909,529	13,909,529	13,909,529	13,909,529	7,693,529	43,839,982	43,839,982	43,839,982	43,839,982	43,839,982	43,839,982	43,839,982	
3	Less: Accumulated Depreciation (C)	(4,031,354)	(4,082,017)	(1,582,680)	916,657	865,994	7,031,331	6,998,800	6,860,830	6,722,860	6,584,890	6,446,920	6,308,950	6,220,980	
4	CWIP - Non Interest Bearing	11,167,011	16,167,011	22,667,011	33,167,011	35,917,011	36,117,011	20,558	20,558	20,558	20,558	20,558	20,558	20,558	
5	Net Investment (Lines 2 + 3 + 4)	21,045,186	25,994,523	34,993,860	47,993,197	50,692,534	50,841,871	50,859,340	50,721,370	50,583,400	50,445,430	50,307,460	50,169,490	50,081,520	
6	Average Net Investment		23,519,855	30,494,192	41,493,529	49,342,866	50,767,203	50,850,606	50,790,355	50,652,385	50,514,415	50,376,445	50,238,475	50,125,505	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		172,800	224,041	304,853	362,522	372,987	373,599	373,157	372,143	371,129	370,116	369,102	368,272	4,034,721
	b Debt Component (Line 6 x Debt Component x 1/12)		49,086	63,641	86,597	102,979	105,951	106,125	105,999	105,712	105,424	105,136	104,848	104,612	1,146,110
8	Investment Expenses														
	a Depreciation (E)		40,574	40,574	40,574	40,574	40,574	22,442	127,881	127,881	127,881	127,881	127,881	127,881	992,598
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		10,089	10,089	10,089	10,089	10,089	10,089	10,089	10,089	10,089	10,089	10,089	10,089	121,068
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		272,549	338,345	442,113	516,164	529,601	512,255	617,126	615,825	614,523	613,222	611,920	610,854	6,294,497
	a Recoverable Costs Allocated to Energy		272,549	338,345	442,113	516,164	529,601	512,255	617,126	615,825	614,523	613,222	611,920	610,854	6,294,497
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		263,254	326,671	427,577	499,405	513,068	496,468	597,869	596,232	594,641	593,769	591,035	589,144	6,089,133
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		263,254	326,671	427,577	499,405	513,068	496,468	597,869	596,232	594,641	593,769	591,035	589,144	6,089,133

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.5% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Crist 7 Flue Gas Conditioning
P.E. 1228
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	1,459,714	1,459,501	1,459,288	1,459,075	1,458,862	1,458,649	1,458,436	1,458,223	1,458,010	1,457,797	1,457,584	1,457,371	1,457,158	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	1,459,714	1,459,501	1,459,288	1,459,075	1,458,862	1,458,649	1,458,436	1,458,223	1,458,010	1,457,797	1,457,584	1,457,371	1,457,158	
6	Average Net Investment		1,459,608	1,459,395	1,459,182	1,458,969	1,458,756	1,458,543	1,458,330	1,458,117	1,457,904	1,457,691	1,457,478	1,457,265	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		10,724	10,722	10,721	10,719	10,717	10,716	10,714	10,713	10,711	10,710	10,708	10,707	128,582
	b Debt Component (Line 6 x Debt Component x 1/12)		3,046	3,046	3,045	3,045	3,044	3,044	3,044	3,043	3,043	3,042	3,042	3,041	36,525
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		213	213	213	213	213	213	213	213	213	213	213	213	2,556
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		13,983	13,981	13,979	13,977	13,974	13,973	13,971	13,969	13,967	13,965	13,963	13,961	167,663
	a Recoverable Costs Allocated to Energy		13,983	13,981	13,979	13,977	13,974	13,973	13,971	13,969	13,967	13,965	13,963	13,961	167,663
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		13,506	13,499	13,519	13,523	13,538	13,542	13,535	13,525	13,515	13,522	13,486	13,465	162,175
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		13,506	13,499	13,519	13,523	13,538	13,542	13,535	13,525	13,515	13,522	13,486	13,465	162,175

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.5% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Low NOx Burners, Crist 6 & 7
P.E.s 1234, 1236, 1242, 1284
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	9,097,924	
3	Less: Accumulated Depreciation (C)	5,384,847	5,358,308	5,331,769	5,305,230	5,278,691	5,252,152	5,225,613	5,199,074	5,172,535	5,145,996	5,119,457	5,092,918	5,066,379	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	14,482,771	14,456,232	14,429,693	14,403,154	14,376,615	14,350,076	14,323,537	14,296,998	14,270,459	14,243,920	14,217,381	14,190,842	14,164,303	
6	Average Net Investment		14,469,502	14,442,963	14,416,424	14,389,885	14,363,346	14,336,807	14,310,268	14,283,729	14,257,190	14,230,651	14,204,112	14,177,573	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		106,307	106,112	105,917	105,722	105,528	105,333	105,138	104,943	104,748	104,553	104,358	104,163	1,262,822
	b Debt Component (Line 6 x Debt Component x 1/12)		30,198	30,142	30,087	30,032	29,976	29,921	29,866	29,810	29,755	29,699	29,644	29,589	358,719
8	Investment Expenses														
	a Depreciation (E)		26,539	26,539	26,539	26,539	26,539	26,539	26,539	26,539	26,539	26,539	26,539	26,539	318,468
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		163,044	162,793	162,543	162,293	162,043	161,793	161,543	161,292	161,042	160,791	160,541	160,291	1,940,009
	a Recoverable Costs Allocated to Energy		163,044	162,793	162,543	162,293	162,043	161,793	161,543	161,292	161,042	160,791	160,541	160,291	1,940,009
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		157,484	157,176	157,199	157,023	156,984	156,807	156,502	156,160	155,832	155,690	155,062	154,594	1,876,513
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		157,484	157,176	157,199	157,023	156,984	156,807	156,502	156,160	155,832	155,690	155,062	154,594	1,876,513

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.5% annually
(F) Applicable amortization period
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: CEMS - Plants Crist, Scholz, Smith, & Daniel
P.E.s 1001, 1060, 1154, 1164, 1217, 1240, 1245, 1247, 1256, 1283, 1286, 1289, 1290, 1311, 1316, 1323, 1324, 1357, 1358, 1364, 1440, 1441, 1442, 1444, 1454, 1459, 1460, 1558, 1570, 1592, 1658, 1829 & 1830
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	7,262,497	7,262,497	7,262,497	7,262,497	7,262,497	7,262,497	7,262,497	7,262,497	7,262,497	7,262,497	7,262,497	7,262,497	7,262,497	
3	Less: Accumulated Depreciation (C)	2,770,487	2,749,305	2,728,123	2,706,941	2,685,759	2,664,577	2,643,395	2,622,213	2,601,031	2,579,849	2,558,667	2,537,485	2,516,303	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	10,032,984	10,011,802	9,990,620	9,969,438	9,948,256	9,927,074	9,905,892	9,884,710	9,863,528	9,842,346	9,821,164	9,799,982	9,778,800	
6	Average Net Investment		10,022,393	10,001,211	9,980,029	9,958,847	9,937,665	9,916,483	9,895,301	9,874,119	9,852,937	9,831,755	9,810,573	9,789,391	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		73,635	73,479	73,323	73,168	73,012	72,856	72,701	72,545	72,390	72,234	72,078	71,923	873,344
	b Debt Component (Line 6 x Debt Component x 1/12)		20,917	20,873	20,828	20,784	20,740	20,696	20,651	20,607	20,563	20,519	20,475	20,430	248,083
8	Investment Expenses														
	a Depreciation (E)		20,954	20,954	20,954	20,954	20,954	20,954	20,954	20,954	20,954	20,954	20,954	20,954	251,448
	b Amortization (F)		228	228	228	228	228	228	228	228	228	228	228	228	2,736
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		1,219	1,219	1,219	1,219	1,219	1,219	1,219	1,219	1,219	1,219	1,219	1,219	14,628
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		116,953	116,753	116,552	116,353	116,153	115,953	115,753	115,553	115,354	115,154	114,954	114,754	1,390,239
	a Recoverable Costs Allocated to Energy		116,953	116,753	116,552	116,353	116,153	115,953	115,753	115,553	115,354	115,154	114,954	114,754	1,390,239
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		112,965	112,725	112,720	112,575	112,527	112,380	112,141	111,877	111,622	111,501	111,031	110,676	1,344,740
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		112,965	112,725	112,720	112,575	112,527	112,380	112,141	111,877	111,622	111,501	111,031	110,676	1,344,740

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances and Ending Balances: Crist. $4,026,450; Scholz $916,802 Smith $1,734,877; Daniel $584,368.11.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Crist: 3.5%; Smith 3.3%; Scholz 4.1%; Daniel 2.8% annually
(F) PE 1364 & 1658 have a 7 year amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Docket No. 110007-EI
2012 Projection Filing
Exhibit RWD-3, Page 8 of 90

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Sub. Contam. Mobile Groundwater Treat. Sys.
P.E. 1007, 3400, & 3412
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	918,024	
3	Less: Accumulated Depreciation (C)	(267,358)	(269,762)	(272,166)	(274,570)	(276,974)	(279,378)	(281,782)	(284,186)	(286,590)	(288,994)	(291,398)	(293,802)	(296,206)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	650,666	648,262	645,858	643,454	641,050	638,646	636,242	633,838	631,434	629,030	626,626	624,222	621,818	
6	Average Net Investment		649,464	647,060	644,656	642,252	639,848	637,444	635,040	632,636	630,232	627,828	625,424	623,020	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		4,772	4,754	4,736	4,719	4,701	4,683	4,666	4,648	4,630	4,613	4,595	4,577	56,094
	b Debt Component (Line 6 x Debt Component x 1/12)		1,355	1,350	1,345	1,340	1,335	1,330	1,325	1,320	1,315	1,310	1,305	1,300	15,930
8	Investment Expenses														
	a Depreciation (E)		2,404	2,404	2,404	2,404	2,404	2,404	2,404	2,404	2,404	2,404	2,404	2,404	28,848
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		8,531	8,508	8,485	8,463	8,440	8,417	8,395	8,372	8,349	8,327	8,304	8,281	100,872
	a Recoverable Costs Allocated to Energy		656	654	653	651	649	647	646	644	642	641	639	637	7,759
	b Recoverable Costs Allocated to Demand		7,875	7,854	7,832	7,812	7,791	7,770	7,749	7,728	7,707	7,686	7,665	7,644	93,113
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		634	631	632	630	629	627	626	624	621	621	617	614	7,506
13	Retail Demand-Related Recoverable Costs (I)		7,595	7,575	7,554	7,534	7,514	7,494	7,474	7,453	7,433	7,413	7,393	7,372	89,804
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		8,229	8,206	8,186	8,164	8,143	8,121	8,100	8,077	8,054	8,034	8,010	7,986	97,310

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Part of PE 1007 depreciable at 2.2% annually, PEs 3400 and 3412 depreciable at 2.2% annually
(F) The amortizable portion of PE 1007 is fully amortized
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Raw Water Well Flowmeters - Plants Crist & Smith
P.E. 1155 & 1606
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	242,973	
3	Less: Accumulated Depreciation (C)	(87,457)	(88,150)	(88,843)	(89,536)	(90,229)	(90,922)	(91,615)	(92,308)	(93,001)	(93,694)	(94,387)	(95,080)	(95,773)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	155,516	154,823	154,130	153,437	152,744	152,051	151,358	150,665	149,972	149,279	148,586	147,893	147,200	
6	Average Net Investment		155,170	154,477	153,784	153,091	152,398	151,705	151,012	150,319	149,626	148,933	148,240	147,547	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,140	1,135	1,130	1,125	1,120	1,115	1,109	1,104	1,099	1,094	1,089	1,084	13,344
	b Debt Component (Line 6 x Debt Component x 1/12)		324	322	321	320	318	317	315	314	312	311	309	308	3,791
8	Investment Expenses														
	a Depreciation (E)		693	693	693	693	693	693	693	693	693	693	693	693	8,316
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,157	2,150	2,144	2,138	2,131	2,125	2,117	2,111	2,104	2,098	2,091	2,085	25,451
	a Recoverable Costs Allocated to Energy		166	165	165	164	164	163	163	162	162	161	161	160	1,956
	b Recoverable Costs Allocated to Demand		1,991	1,985	1,979	1,974	1,967	1,962	1,954	1,949	1,942	1,937	1,930	1,925	23,495
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		160	159	160	159	159	158	158	157	157	156	156	154	1,893
13	Retail Demand-Related Recoverable Costs (I)		1,920	1,914	1,909	1,904	1,897	1,892	1,885	1,880	1,873	1,868	1,861	1,857	22,660
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,080	2,073	2,069	2,063	2,056	2,050	2,043	2,037	2,030	2,024	2,017	2,011	24,553

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning and Ending Balances: Crist, $149,950; Smith $93,023.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Crist 3.5%; Smith 3.3% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Cooling Tower Cell
P.E. 1232
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	500,367	500,198	500,029	499,860	499,691	499,522	499,353	499,184	499,015	498,846	498,677	498,508	498,339	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	500,367	500,198	500,029	499,860	499,691	499,522	499,353	499,184	499,015	498,846	498,677	498,508	498,339	
6	Average Net Investment		500,283	500,114	499,945	499,776	499,607	499,438	499,269	499,100	498,931	498,762	498,593	498,424	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		3,676	3,674	3,673	3,672	3,671	3,669	3,668	3,667	3,666	3,664	3,663	3,662	44,025
	b Debt Component (Line 6 x Debt Component x 1/12)		1,044	1,044	1,043	1,043	1,043	1,042	1,042	1,042	1,041	1,041	1,041	1,040	12,506
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		169	169	169	169	169	169	169	169	169	169	169	169	2,028
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		4,889	4,887	4,885	4,884	4,883	4,880	4,879	4,878	4,876	4,874	4,873	4,871	58,559
	a Recoverable Costs Allocated to Energy		376	376	376	376	376	375	375	375	375	375	375	375	4,505
	b Recoverable Costs Allocated to Demand		4,513	4,511	4,509	4,508	4,507	4,505	4,504	4,503	4,501	4,499	4,498	4,496	54,054
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		363	363	364	364	364	363	363	363	363	363	362	362	4,357
13	Retail Demand-Related Recoverable Costs (I)		4,353	4,351	4,349	4,348	4,347	4,345	4,344	4,343	4,341	4,339	4,338	4,336	52,134
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		4,716	4,714	4,713	4,712	4,711	4,708	4,707	4,706	4,704	4,702	4,700	4,698	56,491

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.5% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Dechlorination System
P.E. 1180, 1248
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	455,323	455,323	455,323	455,323	455,323	455,323	455,323	455,323	455,323	455,323	455,323	455,323	455,323	
3	Less: Accumulated Depreciation (C)	(177,006)	(178,335)	(179,664)	(180,993)	(182,322)	(183,651)	(184,980)	(186,309)	(187,638)	(188,967)	(190,296)	(191,625)	(192,954)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	278,317	276,988	275,659	274,330	273,001	271,672	270,343	269,014	267,685	266,356	265,027	263,698	262,369	
6	Average Net Investment		277,653	276,324	274,995	273,666	272,337	271,008	269,679	268,350	267,021	265,692	264,363	263,034	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,040	2,030	2,020	2,011	2,001	1,991	1,981	1,972	1,962	1,952	1,942	1,933	23,835
	b Debt Component (Line 6 x Debt Component x 1/12)		579	577	574	571	568	566	563	560	557	554	552	549	6,770
8	Investment Expenses														
	a Depreciation (E)		1,329	1,329	1,329	1,329	1,329	1,329	1,329	1,329	1,329	1,329	1,329	1,329	15,948
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		3,948	3,936	3,923	3,911	3,898	3,886	3,873	3,861	3,848	3,835	3,823	3,811	46,553
	a Recoverable Costs Allocated to Energy		304	303	302	301	300	299	298	297	296	295	294	293	3,582
	b Recoverable Costs Allocated to Demand		3,644	3,633	3,621	3,610	3,598	3,587	3,575	3,564	3,552	3,540	3,529	3,518	42,971
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		294	293	292	291	291	290	289	288	286	286	284	283	3,467
13	Retail Demand-Related Recoverable Costs (I)		3,514	3,504	3,492	3,482	3,470	3,460	3,448	3,437	3,426	3,414	3,404	3,393	41,444
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		3,808	3,797	3,784	3,773	3,761	3,750	3,737	3,725	3,712	3,700	3,688	3,676	44,911

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.5% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Diesel Fuel Oil Remediation
P.E. 1270
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	68,923	
3	Less: Accumulated Depreciation (C)	(33,655)	(33,856)	(34,057)	(34,258)	(34,459)	(34,660)	(34,861)	(35,062)	(35,263)	(35,464)	(35,665)	(35,866)	(36,067)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	35,268	35,067	34,866	34,665	34,464	34,263	34,062	33,861	33,660	33,459	33,258	33,057	32,856	
6	Average Net Investment		35,168	34,967	34,766	34,565	34,364	34,163	33,962	33,761	33,560	33,359	33,158	32,957	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		258	257	255	254	252	251	250	248	247	245	244	242	3,003
	b Debt Component (Line 6 x Debt Component x 1/12)		73	73	73	72	72	71	71	70	70	70	69	69	853
8	Investment Expenses														
	a Depreciation (E)		201	201	201	201	201	201	201	201	201	201	201	201	2,412
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		532	531	529	527	525	523	522	519	518	516	514	512	6,268
	a Recoverable Costs Allocated to Energy		41	41	41	41	40	40	40	40	40	40	40	39	483
	b Recoverable Costs Allocated to Demand		491	490	488	486	485	483	482	479	478	476	474	473	5,785
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		40	40	40	40	39	39	39	39	39	39	39	38	471
13	Retail Demand-Related Recoverable Costs (I)		474	473	471	469	468	466	465	462	461	459	457	456	5,581
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		514	513	511	509	507	505	504	501	500	498	496	494	6,052

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.5% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Bulk Tanker Unload Sec Contain Struc
P.E. 1271
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	101,495	
3	Less: Accumulated Depreciation (C)	(58,773)	(59,069)	(59,365)	(59,661)	(59,957)	(60,253)	(60,549)	(60,845)	(61,141)	(61,437)	(61,733)	(62,029)	(62,325)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	42,722	42,426	42,130	41,834	41,538	41,242	40,946	40,650	40,354	40,058	39,762	39,466	39,170	
6	Average Net Investment		42,574	42,278	41,982	41,686	41,390	41,094	40,798	40,502	40,206	39,910	39,614	39,318	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		313	311	308	306	304	302	300	298	295	293	291	289	3,610
	b Debt Component (Line 6 x Debt Component x 1/12)		89	88	88	87	86	86	85	85	84	83	83	82	1,026
8	Investment Expenses														
	a Depreciation (E)		296	296	296	296	296	296	296	296	296	296	296	296	3,552
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		698	695	692	689	686	684	681	679	675	672	670	667	8,188
	a Recoverable Costs Allocated to Energy		54	53	53	53	53	53	52	52	52	52	52	51	630
	b Recoverable Costs Allocated to Demand		644	642	639	636	633	631	629	627	623	620	618	616	7,558
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		52	51	51	51	51	51	50	50	50	50	50	49	606
13	Retail Demand-Related Recoverable Costs (I)		621	619	616	613	611	609	607	605	601	598	596	594	7,290
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		673	670	667	664	662	660	657	655	651	648	646	643	7,896

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.5% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

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2012 Projection Filing
Exhibit RWD-3, Page 14 of 90

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Crist IWW Sampling System
P.E. 1275
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	59,543	
3	Less: Accumulated Depreciation (C)	(34,798)	(34,972)	(35,146)	(35,320)	(35,494)	(35,668)	(35,842)	(36,016)	(36,190)	(36,364)	(36,538)	(36,712)	(36,886)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	24,745	24,571	24,397	24,223	24,049	23,875	23,701	23,527	23,353	23,179	23,005	22,831	22,657	
6	Average Net Investment		24,658	24,484	24,310	24,136	23,962	23,788	23,614	23,440	23,266	23,092	22,918	22,744	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		181	180	179	177	176	175	173	172	171	170	168	167	2,089
	b Debt Component (Line 6 x Debt Component x 1/12)		51	51	51	50	50	50	49	49	49	48	48	47	593
8	Investment Expenses														
	a Depreciation (E)		174	174	174	174	174	174	174	174	174	174	174	174	2,088
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		406	405	404	401	400	399	396	395	394	392	390	388	4,770
	a Recoverable Costs Allocated to Energy		31	31	31	31	31	31	30	30	30	30	30	30	366
	b Recoverable Costs Allocated to Demand		375	374	373	370	369	368	366	365	364	362	360	358	4,404
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		30	30	30	30	30	30	29	29	29	29	29	29	354
13	Retail Demand-Related Recoverable Costs (I)		362	361	360	357	356	355	353	352	351	349	347	345	4,248
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		392	391	390	387	386	385	382	381	380	378	376	374	4,602

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.5% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Sodium Injection System
P.E. 1214 & 1413
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	391,119	
3	Less: Accumulated Depreciation (C)	(98,717)	(99,840)	(100,963)	(102,086)	(103,209)	(104,332)	(105,455)	(106,578)	(107,701)	(108,824)	(109,947)	(111,070)	(112,193)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	292,402	291,279	290,156	289,033	287,910	286,787	285,664	284,541	283,418	282,295	281,172	280,049	278,926	
6	Average Net Investment		291,841	290,718	289,595	288,472	287,349	286,226	285,103	283,980	282,857	281,734	280,611	279,488	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		2,144	2,136	2,128	2,119	2,111	2,103	2,095	2,086	2,078	2,070	2,062	2,053	25,185
	b Debt Component (Line 6 x Debt Component x 1/12)		609	607	604	602	600	597	595	593	590	588	586	583	7,154
8	Investment Expenses														
	a Depreciation (E)		1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	1,123	13,476
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		3,876	3,866	3,855	3,844	3,834	3,823	3,813	3,802	3,791	3,781	3,771	3,759	45,815
	a Recoverable Costs Allocated to Energy		3,876	3,866	3,855	3,844	3,834	3,823	3,813	3,802	3,791	3,781	3,771	3,759	45,815
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		3,744	3,733	3,728	3,719	3,714	3,705	3,694	3,681	3,668	3,661	3,642	3,625	44,314
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		3,744	3,733	3,728	3,719	3,714	3,705	3,694	3,681	3,668	3,661	3,642	3,625	44,314

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning and Ending Balances: Crist, $284,622 and Smith $106,497.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Crist 3.5% annually; Smith 3.3% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Stormwater Collection System
P.E. 1446
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	2,782,600	
3	Less: Accumulated Depreciation (C)	(1,396,276)	(1,403,928)	(1,411,580)	(1,419,232)	(1,426,884)	(1,434,536)	(1,442,188)	(1,449,840)	(1,457,492)	(1,465,144)	(1,472,796)	(1,480,448)	(1,488,100)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	1,386,324	1,378,672	1,371,020	1,363,368	1,355,716	1,348,064	1,340,412	1,332,760	1,325,108	1,317,456	1,309,804	1,302,152	1,294,500	
6	Average Net Investment		1,382,498	1,374,846	1,367,194	1,359,542	1,351,890	1,344,238	1,336,586	1,328,934	1,321,282	1,313,630	1,305,978	1,298,326	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		10,157	10,101	10,045	9,989	9,932	9,876	9,820	9,764	9,707	9,651	9,595	9,539	118,176
	b Debt Component (Line 6 x Debt Component x 1/12)		2,885	2,869	2,853	2,837	2,821	2,805	2,789	2,773	2,758	2,742	2,726	2,710	33,568
8	Investment Expenses														
	a Depreciation (E)		7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	7,652	91,824
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		20,694	20,622	20,550	20,478	20,405	20,333	20,261	20,189	20,117	20,045	19,973	19,901	243,568
	a Recoverable Costs Allocated to Energy		1,592	1,586	1,581	1,575	1,570	1,564	1,559	1,553	1,547	1,542	1,536	1,531	18,736
	b Recoverable Costs Allocated to Demand		19,102	19,036	18,969	18,903	18,835	18,769	18,702	18,636	18,570	18,503	18,437	18,370	224,832
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		1,538	1,531	1,529	1,524	1,521	1,516	1,510	1,504	1,497	1,493	1,484	1,477	18,124
13	Retail Demand-Related Recoverable Costs (I)		18,423	18,359	18,295	18,231	18,166	18,102	18,037	17,974	17,910	17,845	17,782	17,717	216,841
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		19,961	19,890	19,824	19,755	19,687	19,618	19,547	19,478	19,407	19,338	19,266	19,194	234,965

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.3% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Waste Water Treatment Facility
P.E. 1466 & 1643
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	178,962	
3	Less: Accumulated Depreciation (C)	83,718	83,226	82,734	82,242	81,750	81,258	80,766	80,274	79,782	79,290	78,798	78,306	77,814	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	262,680	262,188	261,696	261,204	260,712	260,220	259,728	259,236	258,744	258,252	257,760	257,268	256,776	
6	Average Net Investment		262,434	261,942	261,450	260,958	260,466	259,974	259,482	258,990	258,498	258,006	257,514	257,022	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		1,928	1,924	1,921	1,917	1,914	1,910	1,906	1,903	1,899	1,896	1,892	1,888	22,898
	b Debt Component (Line 6 x Debt Component x 1/12)		548	547	546	545	544	543	542	541	539	538	537	536	6,506
8	Investment Expenses														
	a Depreciation (E)		492	492	492	492	492	492	492	492	492	492	492	492	5,904
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		2,968	2,963	2,959	2,954	2,950	2,945	2,940	2,936	2,930	2,926	2,921	2,916	35,308
	a Recoverable Costs Allocated to Energy		228	228	228	227	227	227	226	226	225	225	225	224	2,716
	b Recoverable Costs Allocated to Demand		2,740	2,735	2,731	2,727	2,723	2,718	2,714	2,710	2,705	2,701	2,696	2,692	32,592
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		220	220	221	220	220	220	219	219	218	218	217	216	2,628
13	Retail Demand-Related Recoverable Costs (I)		2,643	2,638	2,634	2,630	2,626	2,621	2,618	2,614	2,609	2,605	2,600	2,596	31,434
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		2,863	2,858	2,855	2,850	2,846	2,841	2,837	2,833	2,827	2,823	2,817	2,812	34,062

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.3% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Schedule 4P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Daniel Ash Management Project
P.E. 1501, 1535, 1555, & 1819
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	16,234,058	16,234,058	16,234,058	16,234,058	16,234,058	16,234,058	16,234,058	16,234,058	16,234,058	16,234,058	16,234,058	16,234,058	16,234,058	
3	Less: Accumulated Depreciation (C)	(6,466,114)	(6,512,984)	(6,559,854)	(6,606,724)	(6,653,594)	(6,700,464)	(6,747,334)	(6,794,204)	(6,841,074)	(6,887,944)	(6,934,814)	(6,981,684)	(7,028,554)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	9,767,944	9,721,074	9,674,204	9,627,334	9,580,464	9,533,594	9,486,724	9,439,854	9,392,984	9,346,114	9,299,244	9,252,374	9,205,504	
6	Average Net Investment		9,744,509	9,697,639	9,650,769	9,603,899	9,557,029	9,510,159	9,463,289	9,416,419	9,369,549	9,322,679	9,275,809	9,228,939	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		71,593	71,249	70,904	70,560	70,215	69,871	69,527	69,182	68,838	68,494	68,149	67,805	836,387
	b Debt Component (Line 6 x Debt Component x 1/12)		20,337	20,239	20,141	20,043	19,946	19,848	19,750	19,652	19,554	19,456	19,359	19,261	237,586
8	Investment Expenses														
	a Depreciation (E)		37,874	37,874	37,874	37,874	37,874	37,874	37,874	37,874	37,874	37,874	37,874	37,874	454,488
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		8,996	8,996	8,996	8,996	8,996	8,996	8,996	8,996	8,996	8,996	8,996	8,996	107,952
	d Property Taxes		32,136	32,136	32,136	32,136	32,136	32,136	32,136	32,136	32,136	32,136	32,136	32,136	385,632
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		170,936	170,494	170,051	169,609	169,167	168,725	168,283	167,840	167,398	166,956	166,514	166,072	2,022,045
	a Recoverable Costs Allocated to Energy		13,149	13,115	13,081	13,047	13,013	12,979	12,945	12,911	12,877	12,843	12,809	12,775	155,544
	b Recoverable Costs Allocated to Demand		157,787	157,379	156,970	156,562	156,154	155,746	155,338	154,929	154,521	154,113	153,705	153,297	1,866,501
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		12,701	12,663	12,651	12,623	12,607	12,579	12,541	12,500	12,460	12,436	12,372	12,321	150,454
13	Retail Demand-Related Recoverable Costs (I)		152,179	151,785	151,391	150,998	150,604	150,211	149,817	149,423	149,029	148,636	148,242	147,849	1,800,164
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		164,880	164,448	164,042	163,621	163,211	162,790	162,358	161,923	161,489	161,072	160,614	160,170	1,950,618

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 2.8% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

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2012 Projection Filing
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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Smith Water Conservation
P.E. 1601, 1620, 1638
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		116,667	116,667	116,667	350,000	350,000	350,000	350,000	350,000	350,000	350,000	350,000	349,999	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	134,134	
3	Less: Accumulated Depreciation (C)	(30,773)	(31,142)	(31,511)	(31,880)	(32,249)	(32,618)	(32,987)	(33,356)	(33,725)	(34,094)	(34,463)	(34,832)	(35,201)	
4	CWIP - Non Interest Bearing	5,300,001	5,416,668	5,533,335	5,650,002	6,000,002	6,350,002	6,700,002	7,050,002	7,400,002	7,750,002	8,100,002	8,450,002	8,800,001	
5	Net Investment (Lines 2 + 3 + 4)	5,403,362	5,519,660	5,635,958	5,752,256	6,101,887	6,451,518	6,801,149	7,150,780	7,500,411	7,850,042	8,199,673	8,549,304	8,898,934	
6	Average Net Investment		5,461,511	5,577,809	5,694,107	5,927,072	6,276,703	6,626,334	6,975,965	7,325,596	7,675,227	8,024,858	8,374,489	8,724,119	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		40,126	40,980	41,835	43,546	46,115	48,684	51,252	53,821	56,390	58,959	61,527	64,096	607,331
	b Debt Component (Line 6 x Debt Component x 1/12)		11,398	11,641	11,884	12,370	13,099	13,829	14,559	15,289	16,018	16,748	17,478	18,207	172,520
8	Investment Expenses														
	a Depreciation (E)		369	369	369	369	369	369	369	369	369	369	369	369	4,428
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		51,893	52,990	54,088	56,285	59,583	62,882	66,180	69,479	72,777	76,076	79,374	82,672	784,279
	a Recoverable Costs Allocated to Energy		3,992	4,076	4,161	4,330	4,583	4,837	5,091	5,345	5,598	5,852	6,106	6,359	60,330
	b Recoverable Costs Allocated to Demand		47,901	48,914	49,927	51,955	55,000	58,045	61,089	64,134	67,179	70,224	73,268	76,313	723,949
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		3,856	3,935	4,024	4,189	4,440	4,688	4,932	5,175	5,417	5,666	5,898	6,133	58,353
13	Retail Demand-Related Recoverable Costs (I)		46,199	47,176	48,153	50,108	53,045	55,982	58,918	61,855	64,791	67,728	70,664	73,601	698,220
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		50,055	51,111	52,177	54,297	57,485	60,670	63,850	67,030	70,208	73,394	76,562	79,734	756,573

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.3% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

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2012 Projection Filing
Exhibit RWD-3, Page 20 of 90

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Underground Fuel Tank Replacement
P.E. 4397
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	0	0	0	0	0	0	0	0	0	0	0	0	0	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 6 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Applicable depreciation rate or rates.
(F) PE 4397 fully amortized.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Crist FDEP Agreement for Ozone Attainment
P.E. 1031, 1158, 1167, 1199, 1250, 1287
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	333,334	0	333,334	0	333,334	0	266,666	266,666	266,666	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	1,800,000	
	c Retirements		0	0	0	0	687,931	0	0	0	0	0	0	2,021,481	
	d Cost of Removal		0	0	0	0	100,000	0	0	0	68,666	68,667	68,667	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	124,412,987	124,412,987	124,412,987	124,412,987	124,412,987	123,725,056	123,725,056	123,725,056	123,725,056	123,725,056	123,725,056	123,725,056	123,503,575	
3	Less: Accumulated Depreciation (C)	(20,142,288)	(20,539,588)	(20,936,889)	(21,334,191)	(21,731,494)	(21,340,867)	(21,736,166)	(22,131,466)	(22,526,767)	(22,853,402)	(23,180,036)	(23,506,670)	(21,880,490)	
4	CWIP - Non Interest Bearing	0	0	0	0	333,334	333,334	666,668	666,668	1,000,002	1,000,002	1,266,668	1,533,334	0	
5	Net Investment (Lines 2 + 3 + 4)	104,270,699	103,873,399	103,476,098	103,078,796	103,014,827	102,717,523	102,655,558	102,260,258	102,198,291	101,871,656	101,811,688	101,751,720	101,623,085	
6	Average Net Investment		104,072,049	103,674,749	103,277,447	103,046,812	102,866,175	102,686,541	102,457,908	102,229,275	102,034,974	101,841,672	101,781,704	101,687,403	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		764,617	761,698	758,779	757,085	755,758	754,438	752,758	751,078	749,651	748,231	747,790	747,097	9,048,980
	b Debt Component (Line 6 x Debt Component x 1/12)		217,198	216,369	215,540	215,059	214,682	214,307	213,830	213,352	212,947	212,544	212,418	212,222	2,570,468
8	Investment Expenses														
	a Depreciation (E)		362,273	362,273	362,273	362,273	362,273	360,267	360,267	360,267	360,267	360,267	360,267	360,267	4,333,234
	b Amortization (F)		2,357	2,358	2,359	2,360	2,361	2,362	2,363	2,364	2,364	2,364	2,364	2,364	28,340
	c Dismantlement		32,670	32,670	32,670	32,670	32,670	32,670	32,670	32,670	32,670	32,670	32,670	32,670	392,040
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		1,379,115	1,375,368	1,371,621	1,369,447	1,367,744	1,364,044	1,361,888	1,359,731	1,357,899	1,356,076	1,355,509	1,354,620	16,373,062
	a Recoverable Costs Allocated to Energy		1,379,115	1,375,368	1,371,621	1,369,447	1,367,744	1,364,044	1,361,888	1,359,731	1,357,899	1,356,076	1,355,509	1,354,620	16,373,062
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		1,332,083	1,327,914	1,326,526	1,324,980	1,325,047	1,322,006	1,319,391	1,316,471	1,313,966	1,313,058	1,309,244	1,306,476	15,837,162
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		1,332,083	1,327,914	1,326,526	1,324,980	1,325,047	1,322,006	1,319,391	1,316,471	1,313,966	1,313,058	1,309,244	1,306,476	15,837,162

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.5% annually
(F) Portions of 1287 have 7-year amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: SPCC Compliance
P.E. 1272 & 1404
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	929,679	929,679	929,679	929,679	929,679	929,679	929,679	929,679	929,679	929,679	929,679	929,679	929,679	
3	Less: Accumulated Depreciation (C)	(154,622)	(157,332)	(160,042)	(162,752)	(165,462)	(168,172)	(170,882)	(173,592)	(176,302)	(179,012)	(181,722)	(184,432)	(187,142)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	775,057	772,347	769,637	766,927	764,217	761,507	758,797	756,087	753,377	750,667	747,957	745,247	742,537	
6	Average Net Investment		773,702	770,992	768,282	765,572	762,862	760,152	757,442	754,732	752,022	749,312	746,602	743,892	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		5,684	5,664	5,645	5,625	5,605	5,585	5,565	5,545	5,525	5,505	5,485	5,465	66,898
	b Debt Component (Line 6 x Debt Component x 1/12)		1,615	1,609	1,603	1,598	1,592	1,586	1,581	1,575	1,569	1,564	1,558	1,553	19,003
8	Investment Expenses														
	a Depreciation (E)		2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,710	2,710	32,520
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		10,009	9,983	9,958	9,933	9,907	9,881	9,856	9,830	9,804	9,779	9,753	9,728	118,421
	a Recoverable Costs Allocated to Energy		770	768	766	764	762	760	758	756	754	752	750	748	9,108
	b Recoverable Costs Allocated to Demand		9,239	9,215	9,192	9,169	9,145	9,121	9,098	9,074	9,050	9,027	9,003	8,980	109,313
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		744	742	741	739	738	737	734	732	730	728	724	721	8,810
13	Retail Demand-Related Recoverable Costs (I)		8,911	8,887	8,865	8,843	8,820	8,797	8,775	8,751	8,728	8,706	8,683	8,661	105,427
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		9,655	9,629	9,606	9,582	9,558	9,534	9,509	9,483	9,458	9,434	9,407	9,382	114,237

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist $919,836; Smith $9,843. Ending Balances: Crist $919,836; Smith $9,843.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Crist 3.5% ; Smith 3.3% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

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Schedule 4P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Crist Common FTIR Monitor
P.E. 1297
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	62,870	
3	Less: Accumulated Depreciation (C)	(16,321)	(16,504)	(16,687)	(16,870)	(17,053)	(17,236)	(17,419)	(17,602)	(17,785)	(17,968)	(18,151)	(18,334)	(18,517)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	46,549	46,366	46,183	46,000	45,817	45,634	45,451	45,268	45,085	44,902	44,719	44,536	44,353	
6	Average Net Investment		46,458	46,275	46,092	45,909	45,726	45,543	45,360	45,177	44,994	44,811	44,628	44,445	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		341	340	339	337	336	335	333	332	331	329	328	327	4,008
	b Debt Component (Line 6 x Debt Component x 1/12)		97	97	96	96	95	95	95	94	94	94	93	93	1,139
8	Investment Expenses														
	a Depreciation (E)		183	183	183	183	183	183	183	183	183	183	183	183	2,196
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		621	620	618	616	614	613	611	609	608	606	604	603	7,343
	a Recoverable Costs Allocated to Energy		621	620	618	616	614	613	611	609	608	606	604	603	7,343
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		600	599	598	596	595	594	592	590	588	587	583	582	7,104
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		600	599	598	596	595	594	592	590	588	587	583	582	7,104

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.5% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Precipitator Upgrades for CAM Compliance
P.E. 1175, 1191, 1305, 1330, 1461, 1462
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	29,839,678	
3	Less: Accumulated Depreciation (C)	(4,320,969)	(4,405,450)	(4,489,931)	(4,574,412)	(4,658,893)	(4,743,374)	(4,827,855)	(4,912,336)	(4,996,817)	(5,081,298)	(5,165,779)	(5,250,260)	(5,334,741)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	25,518,709	25,434,228	25,349,747	25,265,266	25,180,785	25,096,304	25,011,823	24,927,342	24,842,861	24,758,380	24,673,899	24,589,418	24,504,937	
6	Average Net Investment		25,476,469	25,391,988	25,307,507	25,223,026	25,138,545	25,054,064	24,969,583	24,885,102	24,800,621	24,716,140	24,631,659	24,547,178	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		187,176	186,555	185,934	185,314	184,693	184,072	183,452	182,831	182,210	181,589	180,969	180,348	2,205,143
	b Debt Component (Line 6 x Debt Component x 1/12)		53,169	52,993	52,817	52,640	52,464	52,288	52,112	51,935	51,759	51,583	51,406	51,230	626,396
8	Investment Expenses														
	a Depreciation (E)		84,481	84,481	84,481	84,481	84,481	84,481	84,481	84,481	84,481	84,481	84,481	84,481	1,013,772
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		324,826	324,029	323,232	322,435	321,638	320,841	320,045	319,247	318,450	317,653	316,856	316,059	3,845,311
	a Recoverable Costs Allocated to Energy		324,826	324,029	323,232	322,435	321,638	320,841	320,045	319,247	318,450	317,653	316,856	316,059	3,845,311
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		313,749	312,849	312,605	311,965	311,597	310,953	310,058	309,090	308,147	307,576	306,041	304,826	3,719,456
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		313,749	312,849	312,605	311,965	311,597	310,953	310,058	309,090	308,147	307,576	306,041	304,826	3,719,456

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balancesand Ending Balances: Crist $13,997,696; Smith $15,715,201; Scholz $126,781.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Crist 3.5%; Smith 3.3%; Scholz 4.1% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Plant Groundwater Investigation
P.E. 1218 & 1361
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	0	0	0	0	0	0	0	0	0	0	0	0	0	
6	Average Net Investment		0	0	0	0	0	0	0	0	0	0	0	0	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 6 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Beginning Balances: Crist $0; Scholz $0. Ending Balances: Crist, $0; Scholz $0.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Crist 3.5% annually; Scholz 4.1% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Plant Crist Water Conservation Project
P.E.'s 1178, 1227, 1298
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	19,857,981	19,857,981	19,857,981	19,857,981	19,857,981	19,857,981	19,857,981	19,857,981	19,857,981	19,857,981	19,857,981	19,857,981	19,857,981	
3	Less: Accumulated Depreciation (C)	(1,196,087)	(1,254,013)	(1,311,939)	(1,369,865)	(1,427,791)	(1,485,717)	(1,543,643)	(1,601,569)	(1,659,495)	(1,717,421)	(1,775,347)	(1,833,273)	(1,891,199)	
4	CWIP - Non Interest Bearing (J)	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	18,661,894	18,603,968	18,546,042	18,488,116	18,430,190	18,372,264	18,314,338	18,256,412	18,198,486	18,140,560	18,082,634	18,024,708	17,966,782	
6	Average Net Investment		18,632,931	18,575,005	18,517,079	18,459,153	18,401,227	18,343,301	18,285,375	18,227,449	18,169,523	18,111,597	18,053,671	17,995,745	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		136,896	136,471	136,045	135,619	135,194	134,768	134,343	133,917	133,491	133,066	132,640	132,215	1,614,665
	b Debt Component (Line 6 x Debt Component x 1/12)		38,887	38,766	38,645	38,524	38,403	38,282	38,162	38,041	37,920	37,799	37,678	37,557	458,664
8	Investment Expenses														
	a Depreciation (E)		57,926	57,926	57,926	57,926	57,926	57,926	57,926	57,926	57,926	57,926	57,926	57,926	689,858
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		233,709	233,163	232,616	232,069	231,523	230,976	230,431	229,884	229,337	228,791	228,244	227,698	2,763,187
	a Recoverable Costs Allocated to Energy		17,978	17,936	17,894	17,851	17,809	17,767	17,725	17,683	17,641	17,599	17,557	17,515	212,955
	b Recoverable Costs Allocated to Demand		215,731	215,227	214,722	214,218	213,714	213,209	212,706	212,201	211,696	211,192	210,687	210,183	2,555,486
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		17,365	17,317	17,306	17,271	17,253	17,219	17,172	17,120	17,070	17,041	16,958	16,893	205,985
13	Retail Demand-Related Recoverable Costs (I)		208,064	207,577	207,090	206,604	206,118	205,631	205,146	204,659	204,172	203,686	203,199	202,713	2,464,659
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		225,429	224,894	224,396	223,875	223,371	222,850	222,318	221,779	221,242	220,727	220,157	219,606	2,670,644

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.5% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11
(J) Revised to exclude $73,956 that was incorrectly included in CWIP in December 2008 for PE 1298.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: Plant NPDES Permit Compliance Projects
P.E. 1204 & 1299
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	6,218,040	6,218,040	6,218,040	6,218,040	6,218,040	6,218,040	6,218,040	6,218,040	6,218,040	6,218,040	6,218,040	6,218,040	6,218,040	
3	Less: Accumulated Depreciation (C)	(1,109,012)	(1,127,150)	(1,145,288)	(1,163,426)	(1,181,564)	(1,199,702)	(1,217,840)	(1,235,978)	(1,254,116)	(1,272,254)	(1,290,392)	(1,308,530)	(1,326,668)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	5,109,028	5,090,890	5,072,752	5,054,614	5,036,476	5,018,338	5,000,200	4,982,062	4,963,924	4,945,786	4,927,648	4,909,510	4,891,372	
6	Average Net Investment		5,099,959	5,081,821	5,063,683	5,045,545	5,027,407	5,009,269	4,991,131	4,972,993	4,954,855	4,936,717	4,918,579	4,900,441	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		37,469	37,336	37,203	37,070	36,936	36,803	36,670	36,537	36,403	36,270	36,137	36,004	440,838
	b Debt Component (Line 6 x Debt Component x 1/12)		10,644	10,606	10,568	10,530	10,492	10,454	10,416	10,379	10,341	10,303	10,265	10,227	125,225
8	Investment Expenses														
	a Depreciation (E)		18,138	18,138	18,138	18,138	18,138	18,138	18,138	18,138	18,138	18,138	18,138	18,138	217,656
	b Amortization (F)		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		66,251	66,080	65,909	65,738	65,566	65,395	65,224	65,054	64,882	64,711	64,540	64,369	783,719
	a Recoverable Costs Allocated to Energy		5,096	5,083	5,070	5,057	5,044	5,030	5,017	5,004	4,991	4,978	4,965	4,951	60,286
	b Recoverable Costs Allocated to Demand		61,155	60,997	60,839	60,681	60,522	60,365	60,207	60,050	59,891	59,733	59,575	59,418	723,433
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		4,922	4,908	4,903	4,893	4,887	4,875	4,860	4,845	4,830	4,820	4,796	4,775	58,314
13	Retail Demand-Related Recoverable Costs (I)		58,981	58,829	58,677	58,524	58,371	58,220	58,067	57,916	57,762	57,610	57,458	57,306	697,721
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		63,903	63,737	63,580	63,417	63,258	63,095	62,927	62,761	62,592	62,430	62,254	62,081	756,035

Notes:
(A) Description and reason for 'Other' adjustments to net investment for this project
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal.
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) 3.5% annually
(F) Applicable amortization period.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Docket No. 110007-EI
2012 Projection Filing
Exhibit RWD-3, Page 28 of 90

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: CAIR/CAMR/CAVR Compliance
P.E.s 1034, 1035, 1036, 1037, 1222, 1233, 1279, 1362, 1468, 1469, 1512, 1513, 1646, 1647, 1684, 1810, 1824, & 1826
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	158,346,116	27,383,733	6,220,088	4,006,165	2,138,853	2,195,053	2,035,476	0	26,933,293	
	b Clearings to Plant		0	0	0	158,346,116	27,383,733	6,220,088	4,006,165	2,138,853	2,195,053	2,035,476	0	26,933,293	
	c Retirements		0	0	0	0	15,907	0	0	0	0	0	0	0	
	d Cost of Removal		0	59,959	59,959	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	637,705,516	637,705,516	637,705,516	637,705,516	796,051,632	823,419,458	829,639,546	833,645,711	835,784,564	837,979,617	840,015,093	840,015,093	866,948,386	
3	Less: Accumulated Depreciation (C)	(55,177,177)	(57,351,722)	(59,466,310)	(61,580,900)	(63,755,451)	(66,375,993)	(69,092,276)	(71,826,705)	(74,572,821)	(77,325,177)	(80,083,935)	(82,848,631)	(85,613,327)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	582,528,339	580,353,794	578,239,206	576,124,616	732,296,181	757,043,465	760,547,270	761,819,006	761,211,743	760,654,440	759,931,158	757,166,462	781,335,059	
6	Average Net Investment		581,441,067	579,296,500	577,181,911	654,210,399	744,669,823	758,795,368	761,183,138	761,515,375	760,933,092	760,292,799	758,548,810	769,250,761	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		4,271,848	4,256,091	4,240,556	4,806,484	5,471,089	5,574,870	5,592,413	5,594,853	5,590,575	5,585,871	5,573,058	5,651,685	62,209,393
	b Debt Component (Line 6 x Debt Component x 1/12)		1,213,468	1,208,992	1,204,579	1,365,337	1,554,126	1,583,606	1,588,589	1,589,283	1,588,067	1,586,731	1,583,091	1,605,426	17,671,295
8	Investment Expenses														
	a Depreciation (E)		1,847,172	1,847,172	1,847,172	1,847,172	2,309,068	2,388,900	2,407,044	2,418,729	2,424,969	2,431,371	2,437,309	2,437,309	26,643,387
	b Amortization (F)		12,476	12,478	12,480	12,482	12,484	12,486	12,488	12,490	12,490	12,490	12,490	12,490	149,824
	c Dismantlement		314,897	314,897	314,897	314,897	314,897	314,897	314,897	314,897	314,897	314,897	314,897	314,897	3,778,764
	d Property Taxes		17,634	17,634	17,634	17,634	17,634	17,634	17,634	17,634	17,634	17,634	17,634	17,634	211,608
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		7,677,495	7,657,264	7,637,318	8,364,006	9,679,298	9,892,393	9,933,065	9,947,886	9,948,632	9,948,994	9,938,479	10,039,441	110,664,271
	a Recoverable Costs Allocated to Energy		7,677,495	7,657,264	7,637,318	8,364,006	9,679,298	9,892,393	9,933,065	9,947,886	9,948,632	9,948,994	9,938,479	10,039,441	110,664,271
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		7,415,671	7,393,070	7,386,223	8,092,419	9,377,139	9,587,525	9,623,107	9,631,392	9,626,759	9,633,387	9,599,269	9,682,634	107,048,595
13	Retail Demand-Related Recoverable Costs (I)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		7,415,671	7,393,070	7,386,223	8,092,419	9,377,139	9,587,525	9,623,107	9,631,392	9,626,759	9,633,387	9,599,269	9,682,634	107,048,595

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Beginning Balances: Crist $617,356,712; Smith $4,568,463; Daniel $6,773,199, Scholz $9,007,142. Ending Balances: Crist $857,420,028; Smith $4,568,463; Daniel $6,773,199, Scholz $9,007,142.
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Crist: 3.5%, Plant Smith Steam 3.3%, Smith CT 3.6%, Daniel 2.8%, Scholz 4.1%. Portion of PE 1222 is transmission 2.3%, 3.6%, and 2.5%
(F) Portion of PE 1222 applicable 7 year amortization period beginning in 2008.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11
(J) Project #1222 qualifies for AFUDC treatment. As portions of the project are moved to P-I-S, they are included in the ECRC.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Capital Investments, Depreciation and Taxes
For Project: General Water Quality
P.E.1280
(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Expenditures/Additions		0	0	0	0	0	0	0	0	0	0	0	0	
	b Clearings to Plant		0	0	0	0	0	0	0	0	0	0	0	0	
	c Retirements		0	0	0	0	0	0	0	0	0	0	0	0	
	d Cost of Removal		0	0	0	0	0	0	0	0	0	0	0	0	
	e Salvage		0	0	0	0	0	0	0	0	0	0	0	0	
2	Plant-in-Service/Depreciation Base (B)	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	32,021	
3	Less: Accumulated Depreciation (C)	(22,270)	(22,804)	(23,338)	(23,872)	(24,406)	(24,940)	(25,474)	(26,008)	(26,542)	(27,076)	(27,610)	(28,144)	(28,678)	
4	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0	0	0	0	0	0	
5	Net Investment (Lines 2 + 3 + 4)	9,751	9,217	8,683	8,149	7,615	7,081	6,547	6,013	5,479	4,945	4,411	3,877	3,343	
6	Average Net Investment		9,484	8,950	8,416	7,882	7,348	6,814	6,280	5,746	5,212	4,678	4,144	3,610	
7	Return on Average Net Investment														
	a Equity Component (Line 6 x Equity Component x 1/12) (D)		70	66	62	58	54	50	46	42	38	34	30	27	577
	b Debt Component (Line 6 x Debt Component x 1/12)		20	19	18	16	15	14	13	12	11	10	9	8	165
8	Investment Expenses														
	a Depreciation (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Amortization (F)		534	534	534	534	534	534	534	534	534	534	534	534	6,408
	c Dismantlement		0	0	0	0	0	0	0	0	0	0	0	0	0
	d Property Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0
	e Other (G)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 7 + 8)		624	619	614	608	603	598	593	588	583	578	573	569	7,150
	a Recoverable Costs Allocated to Energy		48	48	47	47	46	46	46	45	45	44	44	44	550
	b Recoverable Costs Allocated to Demand		576	571	567	561	557	552	547	543	538	534	529	525	6,600
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (H)		46	46	45	45	45	45	45	44	44	43	42	42	532
13	Retail Demand-Related Recoverable Costs (I)		556	551	547	541	537	532	528	524	519	515	510	506	6,366
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		602	597	592	586	582	577	573	568	563	558	552	548	6,898

Notes:
(A) Description and reason for 'Other' adjustments to net Investment for this project, if applicable
(B) Applicable beginning of period and end of period depreciable base by production plant names (s), unit(s), or plant account(s).
(C) Description of Adjustments to Reserve for Gross Salvage and Other Recoveries and Cost of Removal
(D) The equity component has been grossed up for taxes. The approved ROE is 12%.
(E) Applicable depreciation rate or rates.
(F) 5 year amortization beginning 2008.
(G) Description and reason for "Other" adjustments to investment expenses for this project.
(H) Line 9a x Line 10 x 1.0007 line loss multiplier
(I) Line 9b x Line 11

Schedule 4P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Working Capital, Mercury Allowance Expenses
For Project: Mercury Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	0	0	0	0	0	0	0	0	0	0	0	0	0	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	Average Net Working Capital Balance		0	0	0	0	0	0	0	0	0	0	0	0	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 4 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
6	Total Return Component (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
7	Expenses														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Mercury Allowance Expense		0	0	0	0	0	0	0	0	0	0	0	0	0
8	Net Expenses (E)		0	0	0	0	0	0	0	0	0	0	0	0	0
9	Total System Recoverable Expenses (Lines 6 + 8)		0	0	0	0	0	0	0	0	0	0	0	0	0
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (B)		0	0	0	0	0	0	0	0	0	0	0	0	0
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	0	0	0	0	0	0

Notes:
(A) Equity Component has been grossed up for taxes. Based on ROE of 12% and weighted income tax rate of 38.575%
(B) Line 9a x Line 10 x 1.0007 line loss multiplier
(C) Line 9b x Line 11
(D) Line 6 is reported on Schedule 6E and 7E
(E) Line 8 is reported on Schedule 4E and 5E

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Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Working Capital, Annual NOx Expenses
For Project: Annual Nox Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Purchases/Transfers		5,954	5,954	5,954	5,954	5,954	8,215	20,440	21,027	6,357	5,954	5,954	5,954	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	1,268,170	1,268,170	1,268,170	1,268,170	1,268,170	1,268,170	1,268,170	1,268,170	1,268,170	1,268,170	1,268,170	1,268,170	1,268,170	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	1,268,170	1,268,170	1,268,170	1,268,170	1,268,170	1,268,170	1,268,170	1,268,170	1,268,170	1,268,170	1,268,170	1,268,170	1,268,170	
4	Average Net Working Capital Balance		1,268,170	1,268,170	1,268,170	1,268,170	1,268,170	1,268,170	1,268,170	1,268,170	1,268,170	1,268,170	1,268,170	1,268,170	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		9,317	9,317	9,317	9,317	9,317	9,317	9,317	9,317	9,317	9,317	9,317	9,317	111,804
	b Debt Component (Line 4 x Debt Component x 1/12)		2,647	2,647	2,647	2,647	2,647	2,647	2,647	2,647	2,647	2,647	2,647	2,647	31,764
6	Total Return Component (D)		11,964	11,964	11,964	11,964	11,964	11,964	11,964	11,964	11,964	11,964	11,964	11,964	143,568
7	Expenses														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Annual Nox Allowance Expense		5,954	5,954	5,954	5,954	5,954	8,215	20,440	21,027	6,357	5,954	5,954	5,954	103,671
8	Net Expenses (E)		5,954	5,954	5,954	5,954	5,954	8,215	20,440	21,027	6,357	5,954	5,954	5,954	103,671
9	Total System Recoverable Expenses (Lines 6 + 8)		17,918	17,918	17,918	17,918	17,918	20,179	32,404	32,991	18,321	17,918	17,918	17,918	247,239
	a Recoverable Costs Allocated to Energy		17,918	17,918	17,918	17,918	17,918	20,179	32,404	32,991	18,321	17,918	17,918	17,918	247,239
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (B)		17,307	17,300	17,329	17,336	17,359	19,557	31,393	31,941	17,728	17,350	17,306	17,281	239,187
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		17,307	17,300	17,329	17,336	17,359	19,557	31,393	31,941	17,728	17,350	17,306	17,281	239,187

Notes:
(A) Equity Component has been grossed up for taxes. Based on ROE of 12% and weighted income tax rate of 38.575%
(B) Line 9a x Line 10 x 1.0007 line loss multiplier
(C) Line 9b x Line 11
(D) Line 6 is reported on Schedule 6E and 7E
(E) Line 8 is reported on Schedule 4E and 5E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Working Capital, Seasonal NOx Expenses
For Project: Seasonal Nox Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	516,439	1,202,586	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	0	0	0	0	0	0	0	0	0	0	0	0	0	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	0	0	0	0	0	0	0	0	0	0	0	0	0	
3	Total Working Capital Balance	0	0	0	0	0	0	0	0	0	0	0	0	0	
4	Average Net Working Capital Balance		0	0	0	0	0	0	0	0	0	0	0	0	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Debt Component (Line 4 x Debt Component x 1/12)		0	0	0	0	0	0	0	0	0	0	0	0	0
6	Total Return Component (D)		0	0	0	0	0	0	0	0	0	0	0	0	0
7	Expenses														
	a Gains		0	0	0	0	0	0	0	0	0	0	0	0	0
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c Seasonal NOx Allowance Expense		0	0	0	0	0	0	0	516,439	1,202,586	0	0	0	1,719,025
8	Net Expenses (E)		0	0	0	0	0	0	0	516,439	1,202,586	0	0	0	1,719,025
9	Total System Recoverable Expenses (Lines 6 + 8)		0	0	0	0	0	0	0	516,439	1,202,586	0	0	0	1,719,025
	a Recoverable Costs Allocated to Energy		0	0	0	0	0	0	0	516,439	1,202,586	0	0	0	1,719,025
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (B)		0	0	0	0	0	0	0	500,008	1,163,678	0	0	0	1,663,686
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		0	0	0	0	0	0	0	500,008	1,163,678	0	0	0	1,663,686

Notes:
(A) Equity Component has been grossed up for taxes. Based on ROE of 12% and weighted income tax rate of 38.575%
(B) Line 9a x Line 10 x 1.0007 line loss multiplier
(C) Line 9b x Line 11
(D) Line 6 is reported on Schedule 6E and 7E
(E) Line 8 is reported on Schedule 4E and 5E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
January 2012 - December 2012

Return on Working Capital, SO2 Expenses
For Project: SO2 Allowances

(in Dollars)

Line	Description	Beginning of Period Amount	Projected January	Projected February	Projected March	Projected April	Projected May	Projected June	Projected July	Projected August	Projected September	Projected October	Projected November	Projected December	End of Period Amount
1	Investments														
	a Purchases/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	b Sales/Transfers		0	0	0	0	0	0	0	0	0	0	0	0	
	c Auction Proceeds/Other		0	0	0	0	0	0	0	0	0	0	0	0	
2	Working Capital														
	a FERC 158.1 Allowance Inventory	8,401,253	8,346,783	8,281,487	8,198,065	8,110,766	8,023,607	7,932,931	7,827,728	7,719,252	7,631,585	7,549,735	7,477,112	7,420,063	
	b FERC 158.2 Allowances Withheld	0	0	0	0	0	0	0	0	0	0	0	0	0	
	c FERC 182.3 Other Regl. Assets - Losses	0	0	0	0	0	0	0	0	0	0	0	0	0	
	d FERC 254 Regulatory Liabilities - Gains	(796,891)	(774,875)	(752,859)	(730,843)	(708,827)	(686,811)	(664,795)	(642,779)	(620,763)	(598,747)	(576,731)	(554,715)	(532,699)	
3	Total Working Capital Balance	7,604,362	7,571,908	7,528,628	7,467,222	7,401,939	7,336,796	7,268,136	7,184,949	7,098,489	7,032,838	6,973,004	6,922,397	6,887,364	
4	Average Net Working Capital Balance		7,588,135	7,550,268	7,497,925	7,434,581	7,369,368	7,302,466	7,226,543	7,141,719	7,065,664	7,002,921	6,947,701	6,904,881	
5	Return on Average Net Working Capital Balance														
	a Equity Component (Line 4 x Equity Component x 1/12) (A)		55,750	55,472	55,087	54,622	54,143	53,651	53,093	52,470	51,911	51,450	51,045	50,730	639,424
	b Debt Component (Line 4 x Debt Component x 1/12)		15,836	15,757	15,648	15,516	15,380	15,240	15,082	14,905	14,746	14,615	14,500	14,410	181,635
6	Total Return Component (D)		71,586	71,229	70,735	70,138	69,523	68,891	68,175	67,375	66,657	66,065	65,545	65,140	821,059
7	Expenses														
	a Gains		(22,016)	(22,016)	(22,016)	(22,016)	(22,016)	(22,016)	(22,016)	(22,016)	(22,016)	(22,016)	(22,016)	(22,016)	(264,192)
	b Losses		0	0	0	0	0	0	0	0	0	0	0	0	0
	c SO2 Allowance Expense		54,470	65,296	83,422	87,299	87,159	90,676	105,203	108,476	87,667	81,850	72,623	57,049	981,190
8	Net Expenses (E)		32,454	43,280	61,406	65,283	65,143	68,660	83,187	86,460	65,651	59,834	50,607	35,033	716,998
9	Total System Recoverable Expenses (Lines 6 + 8)		104,040	114,509	132,141	135,421	134,666	137,551	151,362	153,835	132,308	125,899	116,152	100,173	1,538,057
	a Recoverable Costs Allocated to Energy		104,040	114,509	132,141	135,421	134,666	137,551	151,362	153,835	132,308	125,899	116,152	100,173	1,538,057
	b Recoverable Costs Allocated to Demand		0	0	0	0	0	0	0	0	0	0	0	0	0
10	Energy Jurisdictional Factor		0.9652215	0.9648222	0.9664461	0.9668523	0.9681053	0.9685036	0.9681176	0.9675075	0.9669696	0.9676002	0.9651934	0.9637848	
11	Demand Jurisdictional Factor		0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	0.9644582	
12	Retail Energy-Related Recoverable Costs (B)		100,492	110,558	127,797	131,024	130,462	133,312	146,639	148,941	128,027	121,905	112,188	96,613	1,487,958
13	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	0	0	0	0	0	0
14	Total Jurisdictional Recoverable Costs (Lines 12 + 13)		100,492	110,558	127,797	131,024	130,462	133,312	146,639	148,941	128,027	121,905	112,188	96,613	1,487,958

Notes:
(A) Equity Component has been grossed up for taxes. Based on ROE of 12% and weighted income tax rate of 38.575%
(B) Line 9a x Line 10 x 1.0007 line loss multiplier
(C) Line 9b x Line 11
(D) Line 6 is reported on Schedule 6E and 7E
(E) Line 8 is reported on Schedule 4E and 5E

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Air Quality Assurance Testing
PEs 1006 and 1244

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
This line item includes the audit test trailer and associated support equipment used to conduct Relative Accuracy Test Audits (RATAs) on the Continuous Emission Monitoring Systems (CEMS) as required by the 1990 Clean Air Act Amendments (CAAA).

Accomplishments:
The RATA test trailer CEM system was replaced during the 2002-2003 recovery period. The CEMS trailer was also replaced in 2010. These replacements provide Gulf with the accuracy and reliability needed to accurately measure SO_2, NOx, and CO_2 and to further maintain compliance with CAAA requirements.

Project-to-Date: Plant-in-service of $350,812 projected at December 2012.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist 5, 6 & 7 Precipitator Projects
PEs 1038, 1119, 1216, 1243, and 1249

FPSC Approval: Order No. PSC-94-0044-FOF-EI
Order No. PSC-09-0759-FOF-EI

Description:
The Crist precipitator projects are necessary to improve particulate removal capabilities as a result of burning low sulfur coal. The larger more efficient precipitators with increased collection areas improve particulate collection efficiency.

Accomplishments:
The precipitators have successfully reduced particulate emissions while burning low sulfur coal. The upgraded Crist Unit 7 precipitator was placed in service during 2004 as part of the FDEP agreement. Recent inspections of the Crist Unit 6 precipitator have indicated the precipitator internals will need to be replaced.

Project-to-Date: Plant-in-service of $43,839,982 projected at December 2012.

Progress Summary: Plant Crist will complete detailed design and award the construction bid package in 2011 and the major equipment is expected to be delivered in the Fall of 2011. This project is expected to be completed in the Spring of 2012. Prudently incurred costs associated with the Crist Unit 6 precipitator project were approved for inclusion in the ECRC in Order No. PSC-09-0759-FOF-EI.

Projections: The 2012 projected expenditures for the Plant Crist Unit 6 precipitator project are $25 million.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist 7 Flue Gas Conditioning
PE 1228

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
This project included the injection of sulfur trioxide into the flue gas to enhance particulate removal and improve the collection characteristics of fly ash. Retirement of the Plant Crist Unit 7 flue gas conditioning system was completed during July 2005.

Accomplishments:
The system enhanced particulate removal in the precipitator.

Project-to-Date: $0

Progress Summary: Retired

Projections: N/A

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Low NO_x Burners, Crist 6 & 7
PEs 1234, 1236, 1242, and 1284

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
Low NO_x burners are unique burners installed to decrease the NO_x emissions that are formed during the combustion process. This equipment was installed to meet the requirements of the 1990 Clean Air Act Amendments.

Accomplishments:
The Low NO_x burner systems have proven effective in reducing NO_x emissions. The low NO_x burners on Crist Unit 7 were replaced during the 2003-2004 time frame and the Crist Unit 6 burners were replaced during December 2005.

Project-to-Date: Plant-in-service of $9,097,924 projected at December 2012.

Progress Summary: In-Service

Projections: N/A

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: CEMs – Plant Crist, Scholz, Smith, and Daniel
PEs 1001, 1060, 1154, 1164, 1217, 1240, 1245, 1247, 1256, 1283, 1286, 1289, 1290, 1311, 1316, 1323, 1324, 1357, 1364, 1440, 1441, 1442, 1444, 1454, 1459, 1460, 1558, 1570, 1592, 1658, 1829, and 1830

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Continuous Emission Monitoring (CEM) line item includes dilution extraction emission monitors that measure the concentrations of sulfur dioxide (SO_2), carbon dioxide (CO_2) and nitrogen oxides (NO_x) in the flue gas. Opacity and flow monitors were also installed under this line item. All CEMs monitors were installed pursuant to the 1990 Clean Air Act Amendments (CAAA).

Accomplishments:
The systems at both Gulf and Mississippi Power continue to successfully exceed routine quality assurance/quality control (QA/QC) audits as required by the 1990 CAAA.

Project-to-Date: Plant-in-service of $7,262,497 projected at December 2012.

Progress Summary:
The Plant Scholz Units 1 & 2 CEMS analyzer replacements and the Smith Unit 1 gas analyzers and opacity monitor replacements were completed in 2001 and 2002. The Plant Crist Unit 6 & 7 and the Plant Scholz Units 1&2 flow monitors were replaced during 2005. The Plant Daniel Units 1&2 gas analyzers were also replaced during 2005 and the flow monitors were replaced during 2007. During 2008, the opacity, flow, and gas monitors at Plant Smith and opacity and gas monitors at Plant Scholz were replaced. During the 2009 recovery period, the CEMS project included replacement of opacity monitors at Plant Crist on Units 4 through 7 and the installation of CEMs equipment for the new Plant Crist scrubber stack to monitor SO_2, NOx, CO_2 and flow. Plant Crist completed the installation of two CEMS bypass monitoring systems for Units 4 through 7 in 2011.

Projections: In-Service

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Substation Contamination Mobile Groundwater Treatment System
PEs 1007, 3400, and 3412

FPSC Approval: Order No. PSC-95-1051-FOF-EI

Description:
Three groundwater treatment systems were purchased for the treatment of contaminated groundwater at substation sites.

Accomplishments:
Systems have proven effective in groundwater remediation.

Project-to-Date: Plant-in-service of $918,024 projected at December 2012.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Raw Water Flow Meters; Crist and Smith
PEs 1155 and 1606

FPSC Approval: Order No. PSC-96-1171-FOF-EI

Description:
The Raw Water Flow Meters capital project was necessary for Gulf to comply with the Plant Crist and Plant Smith Consumptive Use and Individual Water Use permits issued by the Northwest Florida Water Management District (NWFWMD). These permits require the installation and monitoring of in-line totaling water flow meters on all existing and future water supply wells. Gulf incurred costs related to the installation and operation of new in-line totaling water flow meters at Plant Crist and Plant Smith for implementation of this new activity.

Accomplishments:
The raw water flow meters have been installed at Plant Crist and Plant Smith.

Project-to-Date: Plant-in-service of $242,973 projected at December 2012.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Cooling Tower Cell
PE 1232

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Crist Cooling Tower cell is a pollution control device which allows condenser cooling water to be continually reinjected into the condenser. The cooling tower reduces water discharge temperatures to meet the National Pollution Discharge Elimination System (NPDES) industrial wastewater requirements.

Accomplishments:
Plant Crist has maintained compliance with the temperature discharge limits as required by the facility's NPDES Permit. The original cooling tower cell was retired during July 2007 when the new Crist Unit 7 cooling tower was placed-in-service.

Project-to-Date: $0

Progress Summary: Retired

Projections: N/A

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Dechlorination System
PE 1248 and PE 1180

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
State and Federal Pollution Discharge Elimination System permits require significant reductions in chlorine concentrations prior to discharge from the plant. The Crist dechlorination system uses sodium bisulfite to chemically eliminate the residual chlorine present in the plant industrial wastewater prior to discharge.

Accomplishments:
The system has been effective in maintaining chlorine discharge limits.

Project-to-Date: Plant-in-service of $455,323 projected at December 2012.

Progress Summary: During 2011, Plant Crist will be replacing the existing sodium bisulfite storage tank as well as installing a new dechlorination system for the Unit 6 and Unit 7 cooling tower blowdowns and the ECUA return water pit. These systems are necessary in order to dechlorinate the industrial wastewater prior to discharge.

Projections: N/A

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Diesel Fuel Oil Remediation
PE 1270

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
The Crist diesel fuel oil remediation project included installing monitoring wells in the vicinity of the Crist diesel tank systems to determine if groundwater contamination was present. The project also included the installation of an impervious cap to reduce migration of contaminants to groundwater.

Accomplishments: Monitoring wells and an impervious cap were installed.

Project-to-Date: Plant-in-service of $68,923 projected at December 2012.

Progress Summary: In-Service

Projections: N/A

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Bulk Tanker Unloading Secondary Containment
PE 1271

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
The Crist Bulk Tanker Unloading Secondary Containment project was necessary to minimize the potential risk of an uncontrolled discharge of pollutants into the waters of the United States. Secondary containment must be installed for tank unloading racks pursuant to the Federal Spill Prevention Control and Countermeasures (SPCC) regulation (40 CFR Part 112).

Accomplishments:
The Plant Crist unloading area secondary containment complies with current SPCC regulatory requirements.

Project-to-Date: Plant-in-service of $101,495 projected at December 2012.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist IWW Sampling System
PE 1275

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
The 1993 revision to Plant Crist's National Pollutant Discharge Elimination System (NPDES) industrial wastewater permit moved the compliance point from the end of the discharge canal to a point upstream of Thompson's Bayou. To allow for this sample point modification, an access dock was constructed in the discharge canal. The Crist Industrial Wastewater (IWW) project also included a small building for monitoring and sampling equipment.

Accomplishments:
The dock is complete and samples are being collected at the required compliance point.

Project-to-Date: Plant-in-service of $59,543 projected at December 2012.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Sodium Injection System
PEs 1214 and 1413

FPSC Approval: Order No. PSC-99-1954-FOF-EI

Description:
The Sodium Injection System line item includes silo storage systems and associated components that inject sodium carbonate directly onto the coal feeder belt to enhance precipitator performance when burning low sulfur coal. Sodium injection is used at Plant Smith on Units 1 and 2 and at Plant Crist on Units 4 and 5. The injection of sodium carbonate as an additive to low sulfur coal reduces opacity levels to maintain compliance with the Clean Air Act provisions.

Accomplishments:
The silo storage and injection system components at Plants Smith and Crist have been installed. These systems are fully operational.

Project-to-Date: Plant-in-service of $391,119 projected at December 2012.

Progress Summary: In Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Smith Stormwater Collection System
PE 1446

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
The National Pollutant Discharge Elimination System (NPDES) stormwater program requires industrial facilities to install stormwater management systems in order to prevent the unpermitted discharge of contaminated stormwater to the surface waters of the United States.

Accomplishments:
No unpermitted discharges have occurred since system installation.

Project-to-Date: Plant-in-service of $2,782,600 projected at December 2012.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Smith Waste Water Treatment Facility
PEs 1466 and 1643

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
During the 1990's a wastewater treatment facility was installed at Plant Smith to replace the septic tank system that was installed in the early 1960's. In April 2004 a new waste-water treatment facility with additional capacity was installed to replace the facility installed in the 1990's. The new treatment plant includes aeration and chlorination of the wastewater prior to discharge in the Plant Smith ash pond.

Accomplishments: Plant Smith has maintained compliance with the NPDES industrial wastewater permit.

Project-to-Date: Plant-in-service of $178,962 projected at December 2012.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Daniel Ash Management Project
PEs 1501, 1535, 1555, and 1819

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The original Daniel Ash Management project included the installation of a dry ash transport system, lining the bottom of the ash pond, closure and capping of the existing fly ash pond, and the expansion of the landfill area. During 2006 Plant Daniel completed construction of a new on-site ash storage facility in preparation for the completion and closure of the existing landfill area.

Accomplishments: Construction of the new on-site ash storage facility was completed in 2006. Portions of the original Daniel ash storage facility were closed in place during 2010.

Project-to-Date: Plant-in-service of $16,234,058 projected at December 2012.

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Smith Water Conservation
PEs 1601, 1620, & 1638

FPSC Approval: **Order No. PSC-01-1788-FOF-EI and**
Order No. PSC-09-0759-FOF-EI

Description:
Specific Condition nine of Plant Smith's consumptive use permit, issued by the Northwest Florida Water Management District (NWFWMD), requires the plant to implement measures to increase water conservation and efficiency at the facility. Phase I of the Smith Water Conservation project consisted of adding pumps, piping, valves, and controls to reclaim water from the ash pond. Phase II, the Smith Closed Loop Cooling System for the laboratory sampling system, was installed during 2005 to further reduce groundwater usage. Phase III includes investigating the feasibility of utilizing reclaimed water at Plant Smith.

Gulf must determine a suitable method to dispose of beneficially used reclaimed water prior to agreeing to accept reclaimed water from suppliers in the Bay County area. Gulf is continuing to investigate the feasibility of utilizing an underground injection well to dispose of used reclaimed water at Plant Smith. Based on the findings of geophysical logs, testing of the deep subsurface intervals later this year and preliminary testing of the upper formation materials, Gulf will make a final determination on whether to move forward with the Plant Smith Reclaimed Water project. If it is determined that the project should be pursued, additional activities such as the installation of additional shallow well(s), monitoring well(s) and the initiation of design of support equipment for the injection of spent fluids into the subsurface would take place. The support equipment necessary for this activity would include but not be limited to the injection pump system, tanks and piping systems.

Accomplishments: Plant Smith estimated that the closed loop cooling project reduced water consumption by approximately 125,000 gallons per day.

Project-to-Date: Plant-in-service of $134,134 projected at December 2012.

Progress Summary: See Accomplishments

Projections: The projected 2012 expenditures for this line item total $3.5 million.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Underground Fuel Tank Replacement
PE 4397

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Underground Fuel Tank Replacement Program provided for the replacement of Gulf's underground storage tanks with new above ground tanks (ASTs). The installation of ASTs significantly reduced the risk of potential petroleum product discharges, groundwater contamination, and subsequent remediation activities.

Accomplishments:
All underground storage tanks have been replaced with above ground tank systems.

Project-to-Date: $0

Progress Summary: See Accomplishments

Projections: N/A

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist FDEP Agreement for Ozone Attainment
PEs 1031, 1158, 1167, 1199, 1250, and 1287

FPSC Approval: Order No. PSC-02-1396-FOF-EI

Description:
The Florida Department of Environmental Protection (FDEP) and Gulf Power entered into an agreement on August 28, 2002 to support Escambia/Santa Rosa County area's effort to maintain compliance with the 8-hour ozone ambient air quality standards. This agreement included a requirement for Gulf to install Selective Catalytic Reduction (SCR) controls on Crist Unit 7, relocate the Crist Unit 7 precipitator, and install a NO_x reduction technology on Plant Crist Unit 6, and Units 4 and 5 if necessary, to meet the NO_x standard specified in the Agreement.

Accomplishments: The new Crist Unit 7 precipitator and SCR were placed in service during 2004 and 2005, respectively. The Crist Unit 6 Selective Non-Catalytic Reduction (SNCR)/low NOx burners with Over-Fired Air (OFA) technologies were then placed in service during November 2005. The Crist Unit 4 and Unit 5 SNCRs were subsequently placed in service during April 2006. The Crist Unit 6 SNCR will be retired during the Spring of 2012 when the Crist Unit 6 SCR is placed in-service.

Project-to-Date: Plant-in-service of $123,503,575 projected at December 2012.

Progress Summary: In-Service

Projections: Gulf plans to replace one layer of the Plant Crist Unit 7 SCR catalyst during 2012. The projected 2012 expenditures for this line item are $1.8 million.

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: SPCC Compliance
PEs 1272 & 1404

FPSC Approval: Order No. PSC-03-1348-FOF-EI

Description:
The SPCC Compliance projects were required as the result of a more stringent July 2002 revision to Title 40 Code of Federal Regulation Part 112, which is commonly referred to as the Spill Prevention Control and Countermeasures (SPCC) regulation. The 2002 regulatory revision specifically included oil-containing electrical equipment within the scope of the regulation. Therefore, oil-filled electrical equipment that has the potential to discharge to navigable waters must be provided with appropriate containment and/or diversionary structures to prevent such a discharge. The 2002 revisions also resulted in oil storage containers having a capacity greater than or equal to 55 gallons being classified as bulk storage containers that are subject to the secondary containment requirements in 40 CFR Part 112.8(c).

Accomplishments: The 2006 SPCC project at Plant Crist routed stormwater from the switchyard drains to the new oil skimming sump where any potential spill could be captured, preventing the oil from reaching surface water. During 2009, Plant Smith installed secondary containment for a padmount transformer located along the ash pond discharge canal.

Project-to-Date: Plant-in-service of $929,679 projected at December 2012.

Progress Summary: In-service

Projections: N/A

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Crist Common FTIR Monitor
PE 1297

FPSC Approval: Order No. PSC-03-1348-FOF-EI

Description:
The purchase of a Fourier Transform Infrared (FTIR) spectrometer, a device used to measure and analyze various low concentration stack gas emissions, was required at Plant Crist under Title V regulations.

Accomplishments: Purchasing the FTIR instrument has enabled Gulf Power to measure ammonia slip emissions as required by the Crist Unit 7 Selective Catalytic Reduction (SCR) air construction permit.

Project-to-Date: Plant-in-service of $62,870 projected at December 2012

Progress Summary: In-Service

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Precipitator Upgrades for Compliance Assurance Monitoring
PEs 1175, 1191, 1305, 1461, and 1462

FPSC Approval: Order No. PSC-04-1187-FOF-EI

Description: Compliance Assurance Monitoring (CAM) Precipitator Upgrades were required to comply with new CAM regulations. CAM requirements are regulated under Title V of the 1990 Clean Air Act Amendments (CAAA) which requires a method of continuously monitoring particulate emissions. Opacity can be used as a surrogate parameter if the precipitator demonstrates a correlation between opacity and particulate matter. Gulf demonstrated this correlation by stack testing in 2003 and 2004, and the results were included as part of the CAM plans in Gulf's Title V Air Permits effective January 2005. Several precipitator upgrades have been necessary to meet the more stringent surrogate opacity standards under CAM.

Accomplishments: The Plant Smith Unit 2 and Unit 1 precipitator upgrades were placed in service during April 2005 and May 2007, respectively. The Plant Scholz Unit 2 precipitator upgrade was completed during December of 2007. The Plant Crist Units 4 and 5 precipitator upgrades were placed in-service during March of 2008.

Project-to-Date: Plant-in-service of $29,839,678 projected at December 2012.

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Plant Groundwater Investigation
PEs 1218 and 1361

FPSC Approval: Order No. PSC-05-1251-FOF-EI

Description: The Florida Department of Environmental Protection (FDEP) lowered the arsenic groundwater standard from 0.05 mg/L to 0.01 mg/L effective January 1, 2005. Historical groundwater monitoring data from Plants Crist and Scholz indicated that these facilities may be unable to comply with the lower standard.

Accomplishments: The Plant Scholz project has been delayed until Gulf receives FDEP's formal response to the Plant Scholz groundwater study. The Plant Crist project has been canceled because Gulf has been released from any remedial action at this site.

Project-to-Date: $0

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Plant Crist Water Conservation Project
PEs 1178, , 1227 and 1298

FPSC Approval: Order No. PSC-05-1251-FOF-EI

Description:
This project is part of the Plant Crist water conservation and consumptive use efficiency program to reduce the demand for groundwater and surface water withdrawals. Specific Condition six of the Northwest Florida Water Management District Individual Water Use Permit Number19850074 issued January 27, 2005 requires Plant Crist to implement measures to increase water conservation and efficiency at the facility. The first Plant Crist Water Conservation project was placed in service during 2006. This project included installing automatic level controls on the fire water tanks to reduce groundwater usage. The second phase of the project involves utilizing reclaimed water from ECUA's proposed wastewater treatment to reduce the demand for groundwater and surface water withdrawals at Plant Crist. The Northwest Florida Water Management District has agreed that this is a valid project to pursue for continued implementation of the water conservation effort.

Accomplishments: Level controls were installed on the fire tank system during 2006. Portions of the plant Crist reclaimed water project were placed in-service in 2009 and 2010. Gulf began receiving reclaimed water from ECUA in November 2010.

Project-to-Date: Plant-in-service of $19,857,981 projected at December 2012.

Progress Summary: See Accomplishments

Projections: N/A

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Plant NPDES Permit Compliance Projects
PE 1204 and 1299

FPSC Approval: Order No. PSC-05-1251-FOF-EI

Description: The water quality based copper effluent limitations included in Chapter 62 Part 302, Florida Administrative Code (F.A.C.) were amended in April 2002 with an effective date of May 2002. The more stringent hardness based standard is included by reference in the Plant Crist National Pollution Discharge Elimination System (NPDES) industrial wastewater permit.

Accomplishments: Plant Crist installed stainless steel condenser tubes on Unit 6 during June 2006 in an effort to meet the revised water quality standards during times of lower hardness in the river water. During 2008 Plant Crist completed the second phase of the project which involved installing a chemical treatment system in the ash pond. During 2010, Gulf completed the third phase of the project that included installing an aeration system in the ash pond.

Project-to-Date: Plant-in-service of $6,218,040 projected at December 2012.

Progress Summary: During 2011, Plant Crist will be installing a new caustic tank and a sulfuric acid tank as part of the ash pond chemical treatment system.

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: CAIR /CAMR/ CAVR Compliance Program
PEs 1034, 1035, 1036, 1037, 1095, 1222, 1233, 1279, 1362, 1468, 1469, 1512, 1513, 1551, 1552, 1646, 1647, 1684, 1810, 1824, and 1826

FPSC Approval: Order No. PSC-06-0972-FOF-EI
Description: This line item includes the prudently incurred costs for compliance with Gulf's Clean Air Interstate Rule (CAIR) or its replacement rule (the Cross-State Air Pollution Control Rule (CSAPR)), the Clean Air Mercury Rule or its replacement (the Utility MACT Rule) and the Clean Air Visibility Rule (CAVR).

Accomplishments:
Immediately after passage of EPA's CAIR and CAMR in 2005, Gulf began extensive engineering, design, and other planning activities to determine the most cost effective strategy for compliance with the CAIR, CAMR, and CAVR requirements. On March 29, 2007, Gulf petitioned the Commission for approval of the Company's plan to achieve and maintain compliance with the CAIR, CAMR, and CAVR. On June 22, 2007, the Office of Public Counsel ("OPC"), the Florida Industrial Power Users' Group ("FIPUG") and Gulf filed a petition for approval of a stipulation regarding the substantive provisions of Gulf's CAIR/CAMR/CAVR Compliance Plan (the "Plan"). That stipulation identified 10 specific components of Gulf's Plan as being reasonable and prudent for implementation and set forth a process for review in connection with the three remaining components of the Plan. On August 14, 2007, the Commission voted to approve the stipulation with the provision that Gulf provide an annual status report regarding cost-effectiveness and prudence of the phases in its Plan into which the Company is moving. The approved Plan includes a more detailed discussion of the planning process and evaluation utilized by Gulf to select the most reasonable and prudent strategy for compliance with these regulations on a plant and/or unit specific basis.

Project-to-Date: Plant-in-service of $866,948,386 projected at December 2012.

Progress Summary: See Accomplishments

Projections

For the purpose of the 2012 projection of ECRC revenue requirements, $229 million is projected to be cleared to plant-in-service for the CAIR/CAMR/CAVR Compliance Program. The projected expenditures are primarily related to the completion of the Plant Crist Unit 6 SCR that will be placed-in-service during the Spring of 2012. Also, as part of the Crist Scrubber project, costs related to the Plant Crist Unit 6 and 7 turbine upgrades will be placed in-service in 2012.

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: General Water Quality
PE 1280

FPSC Approval: Order No. PSC-06-0972-FOF-EI

Description: Gulf Power purchased a boat during 2007 for surface water sampling required by the Plants Crist, Smith and Scholz National Pollutant Discharge Elimination System (NPDES) permits. The permits had new conditions which required Gulf to establish a biological evaluation plan and implementation schedule for each plant.

Accomplishments: The General Water Quality sampling boat was purchased during 2007. It is currently being used to conduct Gulf's surface water sampling for Plants Crist, Smith, and Scholz.

Project-to-Date: Plant-in-service of $32,021 projected at December 2012.

Progress Summary: In-Service

Projections: N/A

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Mercury Allowances

FPSC Approval: Order No. PSC-07-0721-S-EI

Description:
Mercury Allowances were included as part of Gulf's March 2007 CAIR/CAMR/CAVR Compliance Program. The purchase of allowances in conjunction with the retrofit projects comprised the most reasonable, cost-effective means for Gulf to meet the CAIR, CAMR and CAVR requirements. On February 8, 2008, the U.S. Court of Appeals for the District of Columbia Circuit issued an opinion vacating EPA's CAMR. The vacatur became effective with the issuance of the court's mandate on March 14, 2008, nullifying CAMR mercury emission control obligations and monitoring requirements. In response to the CAMR vacatur, mercury allowances have been removed from Gulf's Compliance Program.

Accomplishments: N/A

Project-to-Date: N/A

Progress Summary: N/A

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Annual NO_x Allowances

FPSC Approval: Order No. PSC-07-0721-S-EI

Description:
Although the retrofit installations set forth in Gulf's CAIR/CAMR/CAVR Compliance Program significantly reduce emissions, they will not result in Gulf achieving CAIR / CAVR compliance levels without the purchase of some emission allowances. Thus, Gulf's CAIR/CAMR/CAVR Compliance Program calls for the purchase of allowances. The purchase of allowances in conjunction with the retrofit projects comprises the most reasonable, cost-effective means for Gulf to meet CAIR, or its replacement program, the Cross-State Air Pollution Rule, requirements.

Accomplishments: N/A

Project-to-Date: N/A

Progress Summary:

Gulf began surrendering annual NOx allowances during 2009.

Projections: Gulf is projecting the need to purchase additional annual NOx allowances during 2012. The projected 2012 O&M annual NOx allowance expenses are $103,671.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: Seasonal NO_x Allowances

FPSC Approval: Order No. PSC-07-0721-S-EI

Description:
Although the retrofit installations set forth in Gulf's CAIR/CAMR/CAVR Compliance Program significantly reduce emissions, they will not result in Gulf achieving CAIR/CAVR compliance levels without the purchase of some emission allowances. Thus, Gulf's CAIR/CAMR/CAVR Compliance Program calls for the purchase of allowances. The purchase of allowances in conjunction with the retrofit projects comprises the most reasonable, cost-effective means for Gulf to meet CAIR or its replacement program, the Cross-State Air Pollution Rule, requirements.

Accomplishments: N/A

Project-to-Date: N/A

Progress Summary:

Gulf began surrendering seasonal NOx allowances during 2009.

Projections: Gulf is currently projecting the need to purchase additional seasonal NOx allowances during 2012. Gulf's compliance strategy continues to include possible forward contracts, swaps, and spot market purchases of allowances depending on market prices. The projected 2012 O&M seasonal NOx allowance expenses are $1,719,025.

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects

Title: SO_2 Allowances

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
Part of Gulf's strategy to comply with the Acid Rain Program under the Clean Air Act Amendments of 1990 was to bring several of Gulf's Phase II generating units into compliance early and bank the SO_2 allowances associated with those units. SO_2 reductions under the CAIR program utilize this program requiring an increased rate of surrender beginning in 2010. Gulf's bank was slowly been drawn down over the years due to more allowances being consumed than are allocated to Gulf by EPA. Gulf proposed to meet this shortfall by executing forward contracts to secure allowances supplemented with forward contracts, swaps, and spot market purchases of allowances as prices dictate.

Accomplishments: Gulf executed forward contacts to secure allowances during 2006, 2007, and 2009.

Project-to-Date: N/A

Progress Summary: See Accomplishments

Projections:. The projected 2012 O&M So2 allowance expenses are 716,998.

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.1

Title: Sulfur

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Crist Unit 7 sulfur trioxide (SO_3) flue gas system allowed for the injection of SO_3 into the flue gas stream. The addition of sulfur trioxide to the flue gas improved the collection efficiency of the precipitator when burning a low sulfur coal. Sulfur trioxide agglomerated the particles which in turn enhanced the collection efficiency of the precipitator.

Accomplishments:
The flue gas injection system was retired during 2005.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.2

Title: Air Emission Fees

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
Air Emission Fees are the annual fees required by the Florida Department of Environmental Protection (FDEP) and Mississippi Department of Environmental Quality (MDEQ) under Title V of the 1990 Clean Air Act Amendments.

Accomplishments:
Fees have been paid by due dates.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $825,374

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.3

Title: Title V

FPSC Approval: Order No. PSC-95-0384-FOF-EI

Description:
Title V expenses are associated with the preparation of the Clean Air Act Amendments (CAAA) Title V permit applications and the subsequent implementation of Title V permits. Renewal of the Title V permits is on a five year cycle (i.e. 2005, 2010, etc). Title V permits are periodically revised between renewals to incorporate major changes or modifications of a source.

Accomplishments:
During 2009, the Title V renewal applications were submitted for Plants Crist, Smith, and Scholz and the Pea Ridge Generating Facility. The final permits for Crist, Smith, and Scholz were issued in December 2009 and the Pea Ridge permit was subsequently issued in March 2010. An application to revise the Plant Crist Title V permit to incorporate new operating conditions for the Crist FGD scrubber was submitted in June, 2010 and was subsequently issued in November, 2010. The initial Title V permit application for the Perdido Landfill Gas-to-Energy Facility was submitted in March, 2011 and issuance is expected later in the year.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $121,936

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.4

Title: Asbestos Fees

FPSC Approval: Order No. PSC-94-1207-FOF-EI

Description:
Asbestos Fees include both annual and individual project fees due to the Florida Department of Environmental Protection (FDEP) for asbestos abatement projects.

Accomplishments:
Fees are paid as required by FDEP.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $1,400

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.5

Title: Emission Monitoring

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Emission Monitoring program provides quality assurance/quality control testing for Continuous Emission Monitoring systems, including Relative Accuracy Test Audits and Linearity Tests, as required by the Clean Air Act Amendments (CAAA) of 1990.

Accomplishments:
All systems are in compliance.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $640,443

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.6

Title: General Water Quality

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The General Water Quality activities are undertaken pursuant to the Company's NPDES permit, soil contamination studies, dechlorination, surface and groundwater monitoring studies. This line item also includes expenses for Gulf's Cooling Water Intake program, the Impaired Waters Rule, Storm Water Maintenance, and the Impoundment Integrity project.

Accomplishments:
All activities are on-going in compliance with all applicable environmental laws, rules, and regulations.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $898,066

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.7

Title: Groundwater Contamination Investigation

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Groundwater Contamination Investigation project includes sampling and testing to determine possible environmental impacts to soil and groundwater from past herbicide applications at various substation sites. Once possible environmental impacts to groundwater and soils have been identified cleanup operations are initiated.

Accomplishments:
The Florida Department of Environmental Protection has issued a No Further Action (NFA) letter or Site Rehabilitation Completion Order for 59 sites.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $2,083,868

<u>Gulf Power Company</u>
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.8

Title: State NPDES Administration

FPSC Approval: Order No. PSC-95-1051-FOF-EI

Description:
The State NPDES Administration fees are required by the State of Florida's National Pollutant Discharge Elimination System (NPDES) program administration. Annual and five year permit renewal fees are required for the NPDES industrial wastewater permits at Plants Crist, Smith and Scholz.

Accomplishments:
Gulf has complied with NPDES program administration fee submittal schedule.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $34,500

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.9

Title: Lead & Copper Rule

FPSC Approval: Order No. PSC-95-1051-FOF-EI

Description:
The Lead and Copper Rule expenses include potable water treatment and sampling costs as required by the Florida Department of Environmental Protection (FDEP) regulations.

Accomplishments:
Gulf has complied with all sampling and analytical protocols.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $16,480

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.10

Title: Environmental Auditing/Assessment

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The Environmental Auditing/Assessment program ensures continued compliance with environmental laws, rules, and regulations through auditing and/or assessment of company facilities and operations.

Accomplishments:
Audits and assessments completed to date have demonstrated compliance with environmental laws, rules, and regulations.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $7,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.11

Title: General Solid and Hazardous Waste

FPSC Approval: Order No. PSC-94-0044-FOF-EI

Description:
The General Solid and Hazardous Waste program provides for the proper identification, handling, storage, transportation and disposal of solid and hazardous wastes. This line item also includes O&M expenses associated with Gulf's Spill Prevention Control and Countermeasures (SPCC) plan.

Accomplishments:
Gulf has complied with all hazardous and solid waste regulations.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $457,994

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.12

Title: Above Ground Storage Tanks

FPSC Approval: Order No. PSC-97-1047-FOF-EI

Description:
The Above Ground Storage Tank projects are required under the provisions of Chapter 62-762, F.A.C. which includes specific performance standards applicable to storage tank systems. These performance standards include installation of secondary containment and cathodic protection systems as well as periodic tank integrity testing.

Accomplishments:
Gulf has complied with all applicable storage tank requirements.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $162,457

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.13

Title: **Low NO_x**

FPSC Approval: **Order No. PSC-98-0803-FOF-EI**

Description:
The Low NO_x activity refers to the maintenance expenses associated with the Low NO_x burner tips on Crist Units 4 & 5 and Smith Unit 1.

Accomplishments:
Burner tips on Plant Crist Units 4 & 5 and Plant Smith Unit 1 have been installed and are in-service.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.14

Title: Ash Pond Diversion Curtains

FPSC Approval: Order No. PSC-98-1764-FOF-EI

Description:
The installation of flow diversion curtains in the Plant Crist ash pond were required to effectively increase water retention time in the ash pond. Diversion curtains allow for the sedimentation/precipitation treatment process to be more effective in reducing levels of suspended particulate from the Plant Crist ash pond outfall. Plant Crist replaced the diversion curtains and dredged the pond during the 2009-2010 timeframe.

Accomplishments:
Ash pond diversion curtains have been installed at Plant Crist. Plant Crist plans to complete the ash pond dredging project during third quarter 2010.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $0

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.15

Title: Mercury Emissions

FPSC Approval: Order No. PSC-99-0912-FOF-EI

Description: The Mercury Emissions program pertains to requirements for Gulf to periodically analyze coal shipments for mercury and chlorine content. The Environmental Protection Agency (EPA) mandated that shipments of coal would be analyzed for mercury and chlorine only during 1999. No further notices of continued sampling requirements of coal shipments beyond 1999 have been issued by EPA, therefore no expenses have been planned for this activity.

Accomplishments:
Coal shipments were analyzed as required during 1999. Sampling and analytical requirements are not expected during 2011.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.16

Title: Sodium Injection

FPSC Approval: Order No. PSC-99-1954-FOF-EI

Description:
This line item includes the O&M expenses associated with the sodium injection systems at Plant Smith and Plant Crist. Sodium carbonate is added to the Plant Crist and Plant Smith coal supply to enhance precipitator efficiencies when burning certain low sulfur coals.

Accomplishments:
Sodium carbonate injection is used at Plant Smith and Plant Crist as necessary when low sulfur coal is burned.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $74,000

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.17

Title: Gulf Coast Ozone Study (GCOS)

FPSC Approval: Order No. PSC-00-0476-FOF-EI

Description:
This project referred to Gulf's participation in the Gulf Coast Ozone Study (GCOS) which was a joint modeling analysis between Gulf Power and the State of Florida to provide an improved basis for assessment of eight-hour ozone air quality for Northwest Florida. The goal of the project was to develop strategies for ozone ambient air attainment to supplement the Florida Department of Environmental Protection (FDEP) studies submitted to the Environmental Protection Agency (EPA) for Escambia and Santa Rosa counties.

Accomplishments: The GCOS project was completed during 2006.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.18

Title: SPCC Substation Project

FPSC Approval: Order No. PSC-03-1348-FOF-EI

Description:
During July 2002 EPA published a revision to Title 40 Code of Regulation Part 112, commonly referred to as the Spill Prevention Control and Countermeasures (SPCC) regulation. The revision expanded applicability of the rule to include oil containing electrical transformers and regulators, which had previously been excluded from the SPCC regulations. Gulf was required to install additional containment and/or diversionary structures or equipment at several substations to prevent a potential discharge of mineral oil to navigable waters of the United States or adjoining shorelines.

Accomplishments: Gulf has assessed its substations to determine which sites are subject to the revised SPCC regulations. Additional containment has been added to the substations that were identified as having a reasonable risk of discharging oil into navigable waters of the United States or adjoining shorelines.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: N/A

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.19

Title: FDEP NO_x Reduction Agreement

FPSC Approval: Order No. PSC-02-1396-FOF-EI

Description: This line item includes the O&M expenses associated with the Crist Unit 7 Selective Catalytic Reduction (SCR) and the Crist Units 4, 5, and 6 Selective Non-Catalytic Reduction (SNCR) projects that were included as part of the Florida Department of Environmental Protection (FDEP) and Gulf Power Agreement entered into on August 28, 2002. Anhydrous ammonia, urea, air monitoring, catalyst regeneration, and general operation and maintenance expenses are included in this line item.

Accomplishments: The Crist Unit 7 SCR and the Crist Units 4, 5, and 6 SNCRs are fully operational. The Crist Unit 6 SNCR will be retired when the Crist Unit 6 SCR is placed in-service during the Spring of 2012.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $1,673,050

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of Environmental Compliance Activities and Projects O & M Line Item 1.20

Title: CAIR/CAMR/CAVR Compliance Program

FPSC Approval: Order No. PSC-06-0972-FOF-EI

Description: This line item includes the O&M expenses associated with the stipulated portions of Gulf's CAIR/CAMR/CAVR Compliance program and the Climate Registry. Immediately after the passage of the EPA's CAIR and CAMR in 2005, Gulf began extensive engineering, design, and other planning activities to determine the most cost effective strategy for compliance with the CAIR, CAMR, and CAVR requirements. On March 29, 2007, Gulf petitioned the Commission for approval of the Company's plan to achieve and maintain compliance with the CAIR, CAMR, and CAVR. On June 22, 2007, the Office of Public Counsel ("OPC"), the Florida Industrial Power Users' Group ("FIPUG") and Gulf filed a petition for approval of a stipulation regarding the substantive provisions of Gulf's CAIR/CAMR/CAVR Compliance Plan (the "Plan"). That stipulation identified 10 specific components of Gulf's Plan as being reasonable and prudent for implementation and set forth a process for review in connection with the three remaining components of the Plan. On August 14, 2007, the Commission voted to approve the stipulation with the provision that Gulf provide an annual status report regarding cost-effectiveness and prudence of the phases in its Plan into which the Company is moving. The approved plan includes a more detailed discussion of the planning process and evaluation utilized by Gulf to select the most reasonable and prudent strategy for compliance with these regulations on a plant and/or unit specific basis.

Accomplishments: The Scholz mercury monitoring system, the first Compliance Plan capital project, was placed in-service during August 2008. The Plant Smith Unit 1 and Unit 2 SNCRs were placed in service during May 2009 and December 2008, respectively. The Crist Units 4 -7 scrubber project was placed in-service December of 2009 and the Crist Unit 6 hydrated lime injection system was placed in-service in 2011. The Plant Crist Unit 6 SCR is projected to be placed-in-service in the Spring of 2012. The Crist Unit 6 SNCR will be retired when the Crist Unit 6 SCR is placed in-service. Gulf will be incurring O&M expenses associated with these projects during 2012.

Fiscal Expenditures: N/A
Progress Summary: See Accomplishments

Projections: $16,384,916

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.21

Title: Maximum Achievable Control Technology (MACT)
Information Collection Request (ICR)

FPSC Approval: Order No. PSC-09-0759-FOF-EI

Description: During early 2010 EPA finalized an extensive Information Collection Request (ICR) for coal and oil fired steam electric generating units to support Maximum Achievable Control Technology (MACT) rulemaking under Section 112 of the Clean Air Act (CAA). The ICR required submission of information on control equipment efficiencies, emissions, capital and O&M costs, and fuel data for all coal and oil fired generating units greater than 25MW.

Accomplishments:
Gulf completed the Part I & 2 MACT ICR survey and the Part 3 emissions testing reports during 2010.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $0

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
January 2012-December 2012

Description and Progress Report of
Environmental Compliance Activities and Projects
O & M Line Item 1.22

Title: Crist Water Conservation Program

FPSC Approval: Order No. PSC-08-0775-FOF-EI

Description: Gulf Power entered into an agreement with the Emerald Coast Utilities Authority (ECUA) to begin utilizing reclaimed water from ECUA's proposed wastewater treatment plant to reduce the demand for groundwater and surface water withdrawals. This line item includes general O&M expenses associated with the Plant Crist reclaimed water system such as piping and valve maintenance and pump replacements.

Accomplishments:
Gulfs began receiving reclaimed water from ECUA during November 2010.

Fiscal Expenditures: N/A

Progress Summary: See Accomplishments

Projections: $ 156,000

Schedule 6P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2012 - December 2012

Rate Class	(1) Average 12 CP Load Factor at Meter (%)	(2) Jan - Dec. 2012 Projected Sales at Meter (KWH)	(3) Projected Avg 12 CP at Meter (KW)	(4) Demand Loss Expansion Factor	(5) Energy Loss Expansion Factor	(6) Projected Sales at Generation (KWH)	(7) Projected Avg 12 CP at Generation (KW)	(8) Percentage of KWH Sales at Generation (%)	(9) Percentage of 12 CP Demand at Generation (%)
RS, RSVP	57.312955%	5,611,580,000	1,114,653.88	1.00486476	1.00530097	5,641,326,817	1,120,076.40	47.91951%	56.37207%
GS	63.216034%	296,697,000	53,431.03	1.00485887	1.00529775	298,268,827	53,690.64	2.53361%	2.70218%
GSD, GSDT, GSTOU	73.903822%	2,719,213,000	418,874.58	1.00470565	1.00516604	2,733,260,563	420,845.66	23.21732%	21.18065%
LP, LPT	84.021171%	1,866,508,000	252,899.98	0.98422595	0.98911989	1,846,200,188	248,910.72	15.68230%	12.52737%
PX, PXT, RTP, SBS	94.359108%	1,114,916,000	134,513.54	0.97443817	0.98057253	1,093,256,003	131,075.13	9.28652%	6.59685%
OS-I/II	178.491660%	115,719,000	7,380.65	1.00468934	1.00529485	116,331,715	7,415.26	0.98816%	0.37320%
OS-III	101.451511%	43,632,000	4,896.15	1.00511513	1.00526827	43,861,865	4,921.19	0.37258%	0.24768%
TOTAL		11,768,265,000	1,986,649.81			11,772,505,978	1,986,935.00	100.00000%	100.00000%

Notes:
(1) Average 12 CP load factor based on actual 2009 load research data
(2) Projected KWH sales for the period January 2011 - December 2011
(3) Calculated: (Col 2) / (8,760 x Col 1), (8,784 hours = the # of hours in 1 year)
(4) Based on demand losses identified in Docket No. 010949-EI
(5) Based on energy losses identified in Docket No. 010949-EI
(6) Col 2 x Col 5
(7) Col 3 x Col 4
(8) Col 6 / total for Col 6
(9) Col 7 / total for Col 7

Schedule 7P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Energy & Demand Allocation % By Rate Class
January 2012 - December 2012

Rate Class	(1) Percentage of KWH Sales at Generation (%)	(2) Percentage of 12 CP Demand at Generation (%)	(3) Energy-Related Costs	(4) Demand-Related Costs	(5) Total Environmental Costs	(6) Projected Sales at Meter (KWH)	(7) Environmental Cost Recovery Factors (¢/KWH)
RS, RSVP	47.91951%	56.37207%	69,469,947	5,073,833	74,543,780	5,611,580,000	1.328
GS	2.53361%	2.70218%	3,673,029	243,213	3,916,242	296,697,000	1.320
GSD, GSDT, GSTOU	23.21732%	21.18065%	33,658,649	1,906,389	35,565,038	2,719,213,000	1.308
LP, LPT	15.68230%	12.52737%	22,734,968	1,127,540	23,862,508	1,866,508,000	1.278
PX, PXT, RTP, SBS	9.28652%	6.59685%	13,462,868	593,757	14,056,625	1,114,916,000	1.261
OS-I, OS-II	0.98816%	0.37320%	1,432,557	33,590	1,466,147	115,719,000	1.267
OS-III	0.37258%	0.24768%	540,137	22,293	562,430	43,632,000	1.289
TOTAL	100.00000%	100.00000%	$144,972,155	$9,000,615	153,972,770	11,768,265,000	1.308

Notes:
(1) From Schedule 6P, Col 8
(2) From Schedule 6P, Col 9
(3) Col 1 x Total Energy $ from Schedule 1P, line 5
(4) Col 2 x Total Demand $ from Schedule 1P, line 5
(5) Col 3 + Col 4
(6) Projected KWH sales for the period January 2011 - December 2011
(7) Col 5 / Col 6 x 100

Schedule 8P

Gulf Power Company
Environmental Cost Recovery Clause (ECRC)
Calculation of the Estimated/Actual True-Up Amount
January 2011 - December 2011
FPSC Capital Structure and Cost Rates

Line	Capital Component	(1) Jurisdictional Rate Base Test Year ($000's)	(2) Ratio %	(3) Cost Rate %	(4) Weighted Cost Rate %	(5) Revenue Requirement Rate %	(6) Monthly Revenue Requirement Rate %
1	Bonds	423,185	35.2733	6.44	2.2716	2.2716	
2	Short-Term Debt	33,714	2.8101	4.61	0.1295	0.1295	
3	Preferred Stock	98,680	8.2252	4.93	0.4055	0.6602	
4	Common Stock	492,186	41.0247	12.00	4.9230	8.0147	
5	Customer Deposits	13,249	1.1043	5.98	0.0660	0.0660	
6	Deferred Taxes	122,133	10.1801				
7	Investment Tax Credit	16,584	1.3823	8.99	0.1243	0.1790	
8	Total	1,199,731	100.0000		7.9199	11.3210	0.9434
	ITC Component:						
9	Debt	423,185	41.7321	6.44	2.6875	0.0371	
10	Equity-Preferred	98,680	9.7313	4.93	0.4798	0.0108	
11	-Common	492,186	48.5366	12.00	5.8244	0.1311	
12		1,014,051	100.0000		8.9917	0.1790	
	Breakdown of Revenue Requirement Rate of Return between Debt and Equity:						
13	Total Debt Component (Lines 1, 2, 5, and 9)					2.5042	0.2087
14	Total Equity Component (Lines 3, 4, 10, and 11)					8.8168	0.7347
15	Total Revenue Requirement Rate of Return					11.3210	0.9434

Column:
(1) Capital Structure Approved by FPSC on June 10, 2002 in Docket No. 010949-EI
(2) Column (1) / Total Column (1)
(3) Cost Rates Approved by FPSC on June 10, 2002 in Docket No. 010949-EI
(4) Column (2) x Column (3)
(5) For equity components: Column (4) / (1-.38575); 38.575% = effective income tax rate
For debt components: Column (4)
(6) Column (5) / 12

AFFIDAVIT

STATE OF FLORIDA)
)
COUNTY OF ESCAMBIA)

Docket No. 110007-EI

BEFORE me, the undersigned authority, personally appeared Richard W. Dodd, who being first duly sworn, deposes and says that he is the Rates & Regulatory Matters Supervisor for Gulf Power Company, a Florida corporation, that the foregoing is true and correct to the best of his knowledge, information and belief. He is personally known to me.

Richard W Dodd

Richard W. Dodd
Rates & Regulatory Matters Supervisor

Sworn to and subscribed before me this 24th day of August, 2011.

Natalie Milstead

Notary Public, State of Florida at Large

(SEAL)

NATALIE MILSTEAD
MY COMMISSION # EE091117
EXPIRES May 08, 2015
(407) 398-0153 FloridaNotaryService.com

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: **Environmental Cost Recovery Clause**	)))	Docket No. **110007-EI**

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing has been furnished this 25th day of August, 2011, by U.S. mail to the following:

Martha Carter Brown, Esq.
Senior Counsel
FL Public Service Comm.
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850
mbrown@psc.state.fl.us

Vicki Gordan Kaufman
John C. Moyle
FIPUG
118 N. Gadsden Street
Tallahassee, FL 32301
vkaufman@kagmlaw.com
jmoyle@kagmlaw.com

Paula K. Brown
Tampa Electric Company
P. O. Box 111
Tampa, FL 33601
Regdept@tecoenergy.com

John T. Butler, Esq.
Attorney for Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420
John.Butler@fpl.com

James D. Beasley, Esq.
J. Jeffry Wahlen
Attorneys for Tampa Electric Co.
Ausley & McMullen
P. O. Box 391
Tallahassee, FL 32302
jbeasley@ausley.com

Paul Lewis, Jr.
Progress Energy Florida, Inc.
106 E. College Ave., Ste. 800
Tallahassee, FL 32301
paul.lewisjr@pgnmail.com

Karen S. White, Staff Attorney
c/o AFCESA-ULFSC
139 Barnes Drive, Suite 1
Tyndall AFB, FL 32403-5319
Phone: 850-283-6348
FAX: 850-283-6219
karen.white@tyndall.af.mil

Kenneth Hoffman
Florida Power & Light Company
215 South Monroe Street, Suite 810
Tallahassee, FL 32301-1858
Ken.Hoffman@fpl.com

Gary V. Perko, Esq.
Hopping Green & Sams
P. O. Box 6526
Tallahassee, FL 32314
gperko@hgslaw.com

J.R. Kelly
P. Christensen
C. Rehwinkel
Associate Public Counsel
Office of Public Counsel
111 W. Madison St., Rm. 812
Tallahassee, FL 32399-1400
christensen.patty@leg.state.fl.us
rehwinkel.charles@leg.state.fl.us
kelly.jr@leg.state.fl.us

John T. Burnett, Esq.
Dianne M. Triplett
Progress Energy Service Co.
P. O. Box 14042
St. Petersburg, FL 33733-4042
john.burnett@pgnmail.com

JEFFREY A. STONE
Florida Bar No. 325953
RUSSELL A. BADDERS
Florida Bar No. 007455
STEVEN GRIFFIN
Florida Bar No. 0627569
BEGGS & LANE
P. O. Box 12950
Pensacola FL 32591-2950
(850) 432-2451
Attorneys for Gulf Power Company

Docket 110007 Stipulated Issues
Checklist

GENERIC ISSUES	Utility	Bench Vote
1 Final 2010 true-up amounts	FPL, TECO, and Gulf	
2 Estimated true-up amounts for Jan. 2011 through Dec. 2011	FPL, TECO, and Gulf	
3 Projected environmental cost recovery amounts for Jan. 2012 through Dec. 2012	FPL, TECO, and Gulf	
4 Environmental cost recovery amounts, including true-up amounts, for Jan. 2012 through Dec. 2012	FPL, TECO, and Gulf	
5 Depreciation rates	All Utilities	
6 Jurisdictional separation factors	All Utilities	
7 Environmental cost recovery factors for Jan. 2012 through Dec. 2012	FPL, TECO, and Gulf	
8 Effective date	FPUC only	
FPL ISSUES		
9A St. Lucie cooling water monitoring	FPL	
9B Cost allocation for 9A	FPL	
9C Industrial Boiler Mact Project	FPL	
9D Cost allocation for 9C	FPL	
9E NPDES permit renewal	FPL	
9F Cost allocation for 9E	FPL	
9G 800 MW ESP costs for 2012	FPL	
9H Manatee temporary heating system at Cape Canaveral	FPL	
9I Updated CAIR, CAMR, CAVR/BART projects	FPL	
PEF ISSUES		
10A NPDES permit renewal	PEF	
10B Cost allocation for 10A	PEF	
10C MACT project	PEF	
10D Cost recovery for 10C	PEF	
10E CAIR-related Nox allowances	PEF	
10F Updated review of CAIR compliance plan	PEF	
Gulf ISSUES		
11A Impoundment integrity inspection program	Gulf	
11B Cost allocation for 11A	Gulf	
11C Turbine upgrades	Gulf	
11D CAIR-related Nox allowances	Gulf	
11E Environmental compliance program update	Gulf	

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI EXHIBIT 38
PARTY FLORIDA PUBLIC SERVICE COMMISSION STAFF
DESCRIPTION STIPULATED ISSUES CHECK LIST
DATE 11/01/11 1

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental cost recovery clause. In re: Petition for increase in rates by Gulf Power Company.	DOCKET NO. 110007-EI DOCKET NO. 110138-EI

STIPULATION AND AGREEMENT REGARDING ISSUES RELATED TO COST RECOVERY OF PLANT CRIST TURBINE UPGRADES AND JOINT REQUEST FOR APPROVAL

The Citizens of the State of Florida, through the Office of Public Counsel ("OPC"), the Florida Industrial Power Users Group ("FIPUG"), the Federal Executive Agencies ("FEA"), the Florida Retail Federation ("FRF") and Gulf Power Company ("Gulf Power", "Gulf", or "the Company"), (collectively, the "Parties"), through their respective undersigned counsel, hereby jointly petition the Florida Public Service Commission for entry of an order approving this stipulation regarding the issues of cost recovery associated with turbine upgrades at Gulf's Plant Crist undertaken or planned by Gulf in connection with the Company's Flue Gas Desulfurization ("Scrubber") Project at Plant Crist. The Parties represent that this stipulation fairly and reasonably balances the various positions of the Parties and serves the best interests of the customers they represent and the public interest in general and, therefore, is fully consistent with and supportive of the Commission's long standing policy of encouraging the settlement of contested proceedings in a manner that benefits the ratepayers of utilities subject to the Commission's regulatory jurisdiction and thereby avoids the need for costly, time-consuming and inefficient litigation of matters before the Commission.

BACKGROUND

The Plant Crist Units 4 through 7 Scrubber Project has been developed by Gulf under its CAIR/CAMR/CAVR Compliance Program which was approved for cost recovery through the Environmental Cost Recovery Clause ("ECRC") pursuant to a stipulation dated June 22, 2007 ("2007 Stipulation") between the Parties and the Florida Industrial Power Users Group ("FIPUG") that was approved by the Commission in Order No. PSC-07-0721-S-EI, issued September 5, 2007, In re: Environmental Cost Recovery.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI EXHIBIT 39
PARTY FLORIDA PUBLIC SERVICE COMMISSION
DESCRIPTION STIPULATION AND AGREEMENT (PLANT CRIST)
DATE 11/02/11

Subsequent to entering into the 2007 Stipulation, Gulf decided to install turbine upgrades for Crist Units 6 and 7 as part of the Company's implementation of the Plant Crist Scrubber Project to offset increased station service requirements associated with the scrubber installation. Gulf incorporated the costs associated with the upgrades in its planning process for the Scrubber Project and reflected these costs in all of its updates to Gulf's CAIR/CAMR/CAVR Compliance Program filed with the Commission pursuant to the order approving the 2007 stipulation beginning with the update filed in 2008. Gulf referenced these upgrades in its witness testimony in the ongoing ECRC docket beginning with testimony filed in August 2008.

A dispute has arisen among the parties regarding whether the costs associated with the turbine upgrades are properly within the scope of the 2007 Stipulation or otherwise meet the criteria for recovery through the Environmental Cost Recovery Clause. The following issue has been identified in Docket No. 110007-EI for the hearings in that docket scheduled for November 1, 2 and 3, 2011:

> Issue 11C: Should Gulf be allowed to recover the costs associated with the Plant Crist Units 6 and 7 turbine upgrades?

The following issue has tentatively been identified as part of Staff's preliminary list of issues in Docket No. 110138-EI scheduled for hearing December 12-16, 2011:

> Should the Plant Crist Units 6 and 7 Turbine Upgrade Project be included in rate base and recovered through base rates, rather than through the Environmental Cost Recovery Clause?

STIPULATION

WHEREAS the Parties agree that a dispute exists regarding the appropriateness of the Crist 6 and 7 turbine upgrades for recovery through the ECRC;

WHEREAS the Parties agree that consideration of the Crist 6 and 7 turbine upgrades for recovery through Gulf's base rates is appropriate if recovery is not provided through the ECRC;

WHEREAS the Parties agree that in order to resolve their differences, recovery of the Crist 6 and 7 turbine upgrades through the ECRC should be discontinued on a prospective basis beginning with the ECRC recovery factors to be applied during 2012, and recovery on a prospective basis should be provided through the base rates to be established for Gulf Power Company in Docket No. 110138-EI;

WHEREAS the parties agree that as part of the transition from ECRC recovery to base rate recovery, the parties should be allowed an opportunity to address the amount of recovery through base rates through the filing of supplemental testimony in Gulf's rate case, Docket No. 110138-EI;

WHEREAS, in current Docket No. 110138-EI, involving Gulf Power's petition for authority to increase its base rates, Gulf Power removed the investment and expenses associated with the turbine upgrades from test year rate base and expenses in view of Gulf Power's request to recover for these costs through the Environmental Cost Recovery Clause;

WHEREAS, in prefiled testimony submitted in Docket No. 110138-EI, Gulf Power's witness stated that, in the event the Commission denies recovery of costs associated with the Crist turbine upgrades through the Environmental Cost Recovery Clause, Gulf Power would wish to reverse the ratemaking adjustments in the base rate proceeding so as to include the investment and costs in the test year under consideration in that docket;

WHEREAS, in the absence of an agreement of parties and action by the Commission, no procedural mechanism exists that would accommodate the resolution of the dispute which otherwise has the potential to unnecessarily complicate the proceedings pending before the Commission; and,

WHEREAS, to avoid the necessity of, and inefficiency associated with, litigating the issues related to the investment and costs associated with the turbine upgrades in two separate proceedings, while assuring the subject is presented to the Commission in a manner that is fair to all concerned, the undersigned parties have reached an agreement that will facilitate the

Commission's resolution of all remaining potential issues between the parties regarding the turbine upgrades as part of the pending rate case;

WHEREAS the Parties agree that allowing Gulf the opportunity to file supplemental testimony in Docket No. 110138-EI followed by an opportunity for other parties to respond through testimony and an opportunity for Gulf to then file rebuttal testimony is an appropriate means of allowing the parties to address the issues regarding recovery for the turbine upgrades through base rates; and

WHEREAS the Parties agree that the relief requested in this stipulation is a reasonable resolution of the dispute between the parties;

NOW THEREFORE, based on the foregoing background and recitals, and discussions among the Parties, the Parties stipulate and agree to the following:

1. Gulf's final environmental cost recovery true-up amount for the period ending December 31, 2010 of $861,325 over-recovery as filed in Docket No. 110007-EI will not be opposed by any party to this stipulation.

2. Gulf's estimated environmental cost recovery true-up amount for the period January 2011 through December 2011 of $14,380,513 over-recovery as filed in Docket No. 110007-EI will not be opposed by any party to this stipulation.

3. Gulf's projected environmental cost recovery amount for the period January 2012 through December 2012 previously filed as $169,103,827 shall be revised to $165,075,432 which reflects the removal of all prospective revenue requirements from the ECRC for any of the Crist turbine upgrades and this revised amount will not be opposed by any party to this stipulation.

4. Gulf's total environmental cost recovery amount, including true-up amounts, for the period January 2012 through December 2012 previously filed as $153,861,989 (excluding revenue taxes) shall be revised to $149,833,594 (excluding revenue taxes) which reflects the

removal of all prospective revenue requirements from the ECRC for any of the Crist turbine upgrades and this revised amount will not be opposed by any party to this stipulation.

5. Based on the foregoing changes, Gulf's proposed environmental cost recovery factors for the period January 2012 through December 2012 for each rate group shall be revised to match the values in the following table and these revised amounts will not be opposed by any party to this stipulation:

RATE CLASS	ENVIRONMENTAL COST RECOVERY FACTORS ¢/KWH
RS, RSVP	1.294
GS	1.286
GSD, GSDT, GSTOU	1.273
LP, LPT	1.245
PX, PXT, RTP, SBS	1.227
OS-I/II	1.233
OSIII	1.255

6. As a result of the foregoing removal of the turbine upgrades from the ECRC recovery mechanism on a going forward basis, the only remaining dispute between the Parties is related to the revenue requirement amount that should be included in base rates thereof which shall be addressed by the Commission in Docket No. 110138-EI

7. Gulf Power shall be permitted an opportunity to submit supplemental pre-filed direct testimony and exhibits for the purpose of and limited to addressing the amount and timing of Gulf's investment in the turbine upgrades, the reasonableness of the associated investment and costs, and the extent to which the related investment and costs should be reflected in the revenue requirements the Commission will determine (and the base rates the Commission will prescribe) for Gulf Power in Docket No. 110138-EI. Such supplemental pre-filed direct testimony shall be

filed by Gulf and electronically served on all parties to Docket 110138-EI and Staff no later than November 8, 2011.

8. In response to any supplemental direct testimony and exhibits filed by Gulf Power pursuant to this stipulation, intervenors and Staff shall likewise be permitted an opportunity to submit supplemental pre-filed direst testimony and exhibits subject to the same limitations and scope outlined in paragraph 6 above. Such intervenor testimony shall be filed and electronically served on all parties to Docket 110138-EI and Staff no later than November 15, 2011. Such Staff testimony shall be filed and electronically served on all parties to Docket 110138-EI no later than November 22, 2011.

9. Gulf Power shall be permitted an opportunity to submit rebuttal testimony and exhibits to any supplemental testimony and exhibits submitted by intervenors or staff pursuant to this stipulation. Such supplemental rebuttal testimony shall be filed and electronically served on all parties to Docket 110138-EI and Staff no later than November 29, 2011.

10. All witnesses who prefile testimony and/or exhibits related to the turbine upgrades shall include with the filing any calculations, work papers, or underlying source documents that the sponsoring parties can reasonably foresee would be needed by other parties or Commission Staff to evaluate the testimony or exhibits. The undersigned parties agree to use best efforts to cooperate with respect to the prompt service of and expedited responses to discovery requests associated with prefiled testimony and exhibits submitted pursuant to this Stipulation and Agreement, to include, upon request, making the witness(es) available for deposition on an expedited basis, with the view of ensuring that all parties and Commission Staff have an adequate opportunity to prepare for the hearing on the matters that are the subject of this Stipulation and Agreement.

11. All parties to Docket No. 110138-EI shall endeavor to include statements of their positions on the issue or issues related to the turbine upgrades as part of their prehearing statements which shall remain due on the date set forth in the Order Establishing Procedure. The parties shall be allowed a reasonable opportunity to modify their position(s) to conform to their testimony filed after the due date for their testimony by communicating such modifications to the Commission Staff for inclusion in the Prehearing Order as quickly as possible, but no later than the Prehearing Conference scheduled for November 21, 2011.

12. This Stipulation and Agreement shall become effective immediately upon approval by the Commission. By entering this Stipulation and Agreement, no party waives or concedes any position on the merits of the matters that are the subject of the Stipulation and Agreement, and each party reserves the right to present and support any position regarding the substance of the issues that it determines is consistent with its interests. Each of the undersigned parties agrees to support the approval of the Stipulation and Agreement as serving the objectives of enhancing the efficiency of Commission proceedings and avoiding unnecessary litigation, and as consistent with the public interest.

[REMAINDER OF THIS PAGE INTENTIONALLY LEFT BLANK]

WHEREFORE, the undersigned parties agree and stipulate to the above terms and provisions, and together request the Commission to approve this Stipulation and Agreement at its earliest opportunity.

Respectfully Submitted,

Office of Public Counsel

By______________________________
Joseph A. McGlothlin, Esquire
Florida Bar No. __________
Associate Public Counsel

Patricia A. Christensen, Esquire
Florida Bar No. 0989789
Associate Public Counsel

111 W. Madison Street, Room 812
Tallahassee, Florida 32399
(850) 488-9330

Florida Industrial Power Users Group

By______________________________
John C. Moyle, Jr. Esquire
Florida Bar No.______________
Vicki Gordon Kaufman, Esquire
Florida Bar No.______________
Keefe, Anchors, Gordon & Moyle, PA
118 North Gadsden Street
Tallahassee, Florida 32301
(850) 681-3828

Gulf Power Company

By______________________________ J A Stone
Jeffrey A. Stone, Esquire
Florida Bar No. 325953
Beggs & Lane
Post Office Box 12950
Pensacola, FL 32576-2950
(850) 432-2451

Federal Executive Agencies

By______________________________
Karen White, Esquire
Major Christopher C. Thompson
AFCESA
139 Barnes Drive, Suite 1
Tyndall Air Force Base, Florida 32403
AFLONJACL-ULT
Ph: (850) 283-6348

Florida Retail Federation

By______________________________
Robert Scheffel Wright, Esquire
Florida Bar No.______________
John T. Lavia, Esquire
Florida Bar No.______________
225 South Adams Street, Suite 200
Tallahassee, Florida 32301
(850) 222-7206

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Office of Public Counsel

By Joseph A. McGlothlin
Joseph A. McGlothlin, Esquire
Florida Bar No. __________
Associate Public Counsel

Patricia A. Christensen, Esquire
Florida Bar No. 0989789
Associate Public Counsel

111 W. Madison Street, Room 812
Tallahassee, Florida 32399
(850) 488-9330

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By______________________
John C. Moyle, Jr. Esquire
Florida Bar No.__________
Vicki Gordon Kaufman, Esquire
Florida Bar No.__________
Keefe, Anchors, Gordon & Moyle, PA
118 North Gadsden Street
Tallahassee, Florida 32301
(850) 681-3828

Gulf Power Company

By J A Stone
Jeffrey A. Stone, Esquire
Florida Bar No. 325953
Beggs & Lane
Post Office Box 12950
Pensacola, FL 32576-2950
(850) 432-2451

Federal Executive Agencies

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Karen White, Esquire
Major Christopher C. Thompson
AFCESA
139 Barnes Drive, Suite 1
Tyndall Air Force Base, Florida 32403
AFLONJACL-ULT
Ph: (850) 283-6348

Florida Retail Federation

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Robert Scheffel Wright, Esquire
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Florida Bar No. __________
Associate Public Counsel

Patricia A. Christensen, Esquire
Florida Bar No. 0989789
Associate Public Counsel

111 W. Madison Street, Room 812
Tallahassee, Florida 32399
(850) 488-9330

Florida Industrial Power Users Group

By__________________________
John C. Moyle, Jr. Esquire
Florida Bar No.__________
Vicki Gordon Kaufman, Esquire
Florida Bar No.__________
Keefe, Anchors, Gordon & Moyle, PA
118 North Gadsden Street
Tallahassee, Florida 32301
(850) 681-3828

Gulf Power Company

By J A Stone
Jeffrey A. Stone, Esquire
Florida Bar No. 325953
Beggs & Lane
Post Office Box 12950
Pensacola, FL 32576-2950
(850) 432-2451

Federal Executive Agencies

By__________________________
Karen White, Esquire
Major Christopher C. Thompson
AFCESA
139 Barnes Drive, Suite 1
Tyndall Air Force Base, Florida 32403
AFLONJACL-ULT
Ph: (850) 283-6348

Florida Retail Federation

By Robert Scheffel Wright
Robert Scheffel Wright, Esquire
Florida Bar No. 0966721
John T. Lavia, Esquire
Florida Bar No.__________
225 South Adams Street, Suite 200
Tallahassee, Florida 32301
(850) 222-7206

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Office of Public Counsel

By______________________
Joseph A. McGlothlin, Esquire
Florida Bar No. ___________
Associate Public Counsel

Patricia A. Christensen, Esquire
Florida Bar No. 0989789
Associate Public Counsel

111 W. Madison Street, Room 812
Tallahassee, Florida 32399
(850) 488-9330

Florida Industrial Power Users Group

By______________________
John C. Moyle, Jr. Esquire
Florida Bar No.___________
Vicki Gordon Kaufman, Esquire
Florida Bar No.___________
Keefe, Anchors, Gordon & Moyle, PA
118 North Gadsden Street
Tallahassee, Florida 32301
(850) 681-3828

Gulf Power Company

By______________________
Jeffrey A. Stone, Esquire
Florida Bar No. 325953
Beggs & Lane
Post Office Box 12950
Pensacola, FL 32591-2950
(850) 432-2451

Federal Executive Agencies

By______________________
Karen White, Esquire
Major Christopher C. Thompson
AFCESA
139 Barnes Drive, Suite 1
Tyndall Air Force Base, Florida 32403
AFLOA/ACL-ULT
Ph: (850) 283-6348

Florida Retail Federation

By______________________
Robert Scheffel Wright, Esquire
Florida Bar No.___________
John T. Lavia, Esquire
Florida Bar No.___________
225 South Adams Street, Suite 200
Tallahassee, Florida 32301
(850) 222-7206

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Office of Public Counsel

By________________________
Joseph A. McGlothlin, Esquire
Florida Bar No: __________
Associate Public Counsel

Patricia A. Christensen, Esquire
Florida Bar No. 0989789
Associate Public Counsel

111 W. Madison Street, Room 812
Tallahassee, Florida 32399
(850) 488-9330

Florida Industrial Power Users Group

By Vicki Gordon Kaufman
John C. Moyle, Jr. Esquire
Florida Bar No. 727016
Vicki Gordon Kaufman, Esquire
Florida Bar No. 286672
Keefe, Anchors, Gordon & Moyle, PA
118 North Gadsden Street
Tallahassee, Florida 32301
(850) 681-3828

Gulf Power Company

By J A Stone
Jeffrey A. Stone, Esquire
Florida Bar No. 325953
Beggs & Lane
Post Office Box 12950
Pensacola, FL 32576-2950
(850) 432-2451

Federal Executive Agencies

By________________________
Karen White, Esquire
Major Christopher C. Thompson
AFCESA
139 Barnes Drive, Suite 1
Tyndall Air Force Base, Florida 32403
AFLONJACL-ULT
Ph: (850) 283-6348

Florida Retail Federation

By________________________
Robert Scheffel Wright, Esquire
Florida Bar No.__________
John T. Lavia, Esquire
Florida Bar No.__________
225 South Adams Street, Suite 200
Tallahassee, Florida 32301
(850) 222-7206

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: **Environmental Cost Recovery Clause**)

Docket No. **110007-EI**

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing has been furnished by electronic mail this 28th day of October, 2011 to the following:

Martha Carter Brown, Esq.
Senior Counsel
FL Public Service Comm.
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850
mbrown@psc.state.fl.us

Vicki Gordan Kaufman
John C. Moyle
FIPUG
118 N. Gadsden Street
Tallahassee, FL 32301
vkaufman@kagmlaw.com
jmoyle@kagmlaw.com

Paula K. Brown
Tampa Electric Company
P. O. Box 111
Tampa, FL 33601
Regdept@tecoenergy.com

John T. Butler, Esq.
Attorney for Florida Power & Light Company
700 Universe Boulevard
Juno Beach, FL 33408-0420
John.Butler@fpl.com

James D. Beasley, Esq.
J. Jeffry Wahlen
Attorneys for Tampa Electric Co.
Ausley & McMullen
P. O. Box 391
Tallahassee, FL 32302
jbeasley@ausley.com

Paul Lewis, Jr.
Progress Energy Florida, Inc.
106 E. College Ave., Ste. 800
Tallahassee, FL 32301
paul.lewisjr@pgnmail.com

Karen S. White, Staff Attorney
c/o AFCESA-ULFSC
139 Barnes Drive, Suite 1
Tyndall AFB, FL 32403-5319
Phone: 850-283-6348
FAX: 850-283-6219
karen.white@tyndall.af.mil

Kenneth Hoffman
Florida Power & Light Company
215 South Monroe Street, Suite 810
Tallahassee, FL 32301-1858
Ken.Hoffman@fpl.com

Gary V. Perko, Esq.
Hopping Green & Sams
P. O. Box 6526
Tallahassee, FL 32314
gperko@hgslaw.com

J.R. Kelly
P. Christensen
C. Rehwinkel
Associate Public Counsel
Office of Public Counsel
111 W. Madison St., Rm. 812
Tallahassee, FL 32399-1400
christensen.patty@leg.state.fl.us
rehwinkel.charles@leg.state.fl.us
kelly.jr@leg.state.fl.us

John T. Burnett, Esq.
Dianne M. Triplett
Progress Energy Service Co.
P. O. Box 14042
St. Petersburg, FL 33733-4042
john.burnett@pgnmail.com

JEFFREY A. STONE
Florida Bar No. 325953
RUSSELL A. BADDERS
Florida Bar No. 007455
STEVEN GRIFFIN
Florida Bar No. 0627569
BEGGS & LANE
P. O. Box 12950
Pensacola FL 32591-2950
(850) 432-2451
Attorneys for Gulf Power Company

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

IN RE: Petition for Increase in Rates)
by Gulf Power Company) Docket No. 110138-EI
)
)

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true copy of the foregoing was furnished by electronic mail the 28th day of October, 2011, on the following:

Office of Public Counsel
J. R. Kelly/Joseph A. McGlothlin/Erik Sayler
c/o The Florida Legislature
111 W. Madison Street,
Room 812
Tallahassee, FL 32393-1400
mcglothlin.joseph@leg.state.fl.us
merchant.tricia@leg.state.fl.us
Kelly.jr@leg.state.fl.us
Sayler.erik@leg.state.fl.us

Caroline Klancke
Keino Young
Martha Barrera
Office of the General Counsel
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850
mbarrera@psc.state.fl.us
cklancke@psc.state.fl.us
kyoung@psc.state.fl.us

Florida Retail Federation
227 South Adams Street
Tallahassee, FL 32301

Gunster Law Firm
Charles A. Guyton
215 S. Monroe St.,
Suite 618
Tallahassee, FL 32301
cguyton@gunster.com

Richard Melson
705 Piedmont Drive
Tallahassee, FL 32312
rick@rmelsonlaw.com

Federal Executive Agencies
c/o Major Christopher C. Thompson
Ms. Karen White
AFLOA/JACL-ULFSC
139 Barnes Drive, Suite 1
Tyndall Air Force Base,
Florida 32403
chris.thompson.2@tyndall.af.mil
karen.white@tyndall.af.mil

Florida Industrial Power
Users Group
Vicki G. Kaufman/
Jon C. Moyle,Jr.
c/o Keefe Law Firm
118 North Gadsden Street
Tallahassee, FL 32301
vkaufman@kagmlaw.com

Gardner Law Firm
Robert Scheffel Wright
John T. La Via,
1300 Thomaswood Drive
Tallahassee, FL 32308
schef@gbwlegal.com

JEFFREY A. STONE
Florida Bar No. 325953
RUSSELL A. BADDERS
Florida Bar No. 007455
STEVEN R. GRIFFIN
Florida Bar No. 0627569
BEGGS & LANE
P. O. Box 12950
Pensacola FL 32591-2950
(850) 432-2451
Attorneys for Gulf Power Company

40

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental cost recovery clause.	DOCKET NO. 110007-EI
	DATED: OCTOBER 14, 2011

PROGRESS ENERGY FLORIDA'S NOTICE OF FILING REVISIONS TO TESTIMONY AND EXHIBIT

PROGRESS ENERGY FLORIDA, INC., ("PEF"), hereby provides notice of filing revisions to the testimony of Thomas G. Foster and Exhibit No. __ (TGF-3) filed on August 26, 2011, as further described below:

1. The revisions reflect PEF's agreement with Staff to utilize a three year (rather than one year) amortization period for the proposed regulatory asset associated with PEF's remaining CAIR NOx allowances. Changing the amortization period results in a reduction of PEF's 2012 revenue requirements by $13,892,463.

2. PEF also has corrected two minor math errors that are described in PEF's response to Staff Interrogatory No.18b. The impact of correcting the math errors is to increase 2012 revenue requirements by $26,250.

3. The combined impact of the revisions described above is to reduce 2012 revenue requirements by $13,866,213 and to reduce PEF's proposed residential ECRC rates from $5.83/mWh to $5.45/mWh. These changes are reflected in Revised Forms 42-1P, 42-2P, 42-3P, 42-4P page 5 of 16, 42-5P page 5 of 18 and 42-7P of Exhibit No. _ (TGF-3), which are provided in Attachment "A" to this Notice. Corresponding revisions to Mr. Foster's testimony are specified in Attachment "B" to this Notice.

DATED this 17th day of October, 2011.

HOPPING GREEN & SAMS, P.A.

By:

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

Attorneys for Progress Energy Florida, Inc.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of the foregoing has been furnished via electronic-mail and regular U.S. mail this 14th day of October, 2011.

Martha Carter Brown
Office of General Counsel
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850
mbrown@psc.state.fl.us

John T. Butler, Esq.
Florida Power & Light Co.
700 Universe Blvd.
Juno Beach, FL 33408-0420
john.butler@fpl.com

Mr. Wade Litchfield
Florida Power & Light Co.
215 S. Monroe Street, Suite 810
Tallahassee, FL 32301
wade.litchfield@fpl.com

James D. Beasley, Esq.
Ausley & McMullen
P.O. Box 391
Tallahassee, FL 32302
jbeasley@ausley.com

John W. McWhirter, Jr.
McWhirter Reeves & Davidson, P.A.
P.O. Box 3350
Tampa, FL 33601-3350
jmcwhirter@mac-law.com

Jeffrey A. Stone, Esq.
Russell A. Badders, Esq.
Beggs & Lane Law Firm
P.O. Box 12950
Pensacola, FL 32591-2950
jas@beggslane.com
rab@beggslane.com

Susan Ritenour
Gulf Power Company
One Energy Place
Pensacola, FL 32520-0780
sdriteno@southernco.com

Capt. Shayla McNeill, USAF
Federal Executive Agencies
c/o AFLSA / JACL-ULT
139 Barnes Drive, Suite 1
Tyndall AFB, FL 32403
Shayla.mcneill@tyndall.af.mil

J.R. Kelly
Charles J. Rehwinkel
Office of Public Counsel
c/o The Florida Legislature
111 West Madison Street, Rm. 812
Tallahassee, FL 32399
Kelly.jr@leg.state.fl.us
rehwinkel.charles@leg.state.fl.us

Paula K. Brown
Tampa Electric Company
Administrator, Regulatory Coordination
P.O. Box 111
Tampa, FL 33601-0111
Regdept@tecoenergy.com

R. Alexander Glenn
Deputy General Counsel - Florida
John T. Burnett
Associate General Counsel - Florida
Progress Energy Service Company, LLC
P.O. Box 14042
St. Petersburg, FL 33733
alex.glenn@pgnmail.com
john.burnett@pgnmail.com

Paul Lewis, Jr.
Progress Energy Florida, Inc.
106 East College Avenue, Suite 800\Tallahassee, FL 32301-7740
paul.lewisjr@pgnmail.com

Attorney

ATTACHMENT "A"

Revised Schedules to Exhibit No. __ (TGF-3)
originally filed on August 26, 2011

Revised Form 42-1P

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Total Jurisdictional Amount to be Recovered
For the Projected Period
JANUARY 2012 - DECEMBER 2012
(in Dollars)

Line		Energy ($)	Transmission Demand ($)	Distribution Demand ($)	Production Demand ($)	Total ($)
1	Total Jurisdictional Rev. Req. for the projected period					
a	Projected O&M Activities (Form 42-2P, Lines 7 through 9)	$ 38,872,301	$ 1,384,728	$ 2,426,549	$ 1,101,172	$ 43,784,750
b	Projected Capital Projects (Form 42-3P, Lines 7 through 9)	161,060,912	0	1,689	2,455,320	163,517,921
c	Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b)	199,933,213	1,384,728	2,428,238	3,556,492	207,302,671
2	True-up for Estimated Over/(Under) Recovery for the current period January 2011 - December 2011 (Form 42-2E, Line 5 + 6 + 10)	2,339,353	(2,105,287)	283,939	2,034,333	2,552,337
3	Final True-up for the period January 2010 - December 2010 (Form 42-1A, Line 3)	5,926,762	(331,768)	(100,916)	738,761	6,232,839
4	Total Jurisdictional Amount to Be Recovered/(Refunded) in the Projection period January 2012 - December 2012 (Line 1 - Line 2 - Line 3)	191,667,099	3,821,783	2,245,215	783,397	198,517,495
5	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier of 1.00072)	$ 191,805,099	$ 3,824,535	$ 2,246,832	$ 783,962	$ 198,660,428

Revised Form 42-2P

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2012 - DECEMBER 2012

O&M Activities
(in Dollars)

Line	Description	Projected Jan - 12	Projected Feb - 12	Projected Mar - 12	Projected Apr - 12	Projected May - 12	Projected Jun - 12	Projected Jul - 12	Projected Aug - 12	Projected Sep - 12	Projected Oct - 12	Projected Nov - 12	Projected Dec - 12	End of Period Total
1	Description of O&M Activities													
	1 Transmission Substation Environmental Investigation, Remediation, and Pollution Prevention	$ 165,997	$ 165,997	$ 165,997	$ 165,997	$ 165,997	$ 165,997	$ 165,997	$ 165,997	$ 165,997	$ 165,997	$ 165,997	$ 165,997	$ 1,991,964
	1a Distribution Substation Environmental Investigation, Remediation, and Pollution Prevention	174,976	174,976	174,976	174,976	174,976	174,976	174,976	174,976	174,976	174,976	174,976	174,976	2,099,712
	2 Distribution System Environmental Investigation, Remediation, and Pollution Prevention	0	0	20,000	0	0	0	0	0	20,000	291,000	0	0	331,000
	3 Pipeline Integrity Management, Review/Update Plan and Risk Assessments - Intm	166,083	166,083	166,083	166,083	166,083	66,083	66,083	66,083	141,083	141,083	141,083	66,087	1,518,000
	4 Above Ground Tank Secondary Containment - Pkg	0	0	0	0	0	0	0	0	0	0	0	0	0
	5 SO2 & NOx Emissions Allowances - Energy	601,203	595,228	607,694	595,992	614,848	618,309	621,182	622,113	616,725	611,841	615,265	614,576	7,334,975
	6 Phase II Cooling Water Intake 316(b) - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
	6a Phase II Cooling Water Intake 316(b) - Intm	0	0	0	0	0	0	0	0	0	0	0	0	0
	7.2 CAIR - Peaking	19,500	25,000	5,000	0	0	5,000	0	0	5,000	0	21,600	9,600	90,700
	7.4 CAIR Crystal River - Base	862,800	957,376	1,366,520	1,074,554	1,045,445	974,883	920,402	1,257,179	1,010,441	966,388	1,537,144	1,426,492	13,399,625
	7.4 CAIR Crystal River - Energy	1,615,668	1,500,473	1,695,076	1,413,960	1,620,966	1,644,777	1,769,652	1,788,552	1,668,222	667,943	1,114,725	1,947,962	18,447,976
	7.4 CAIR Crystal River - A&G	14,336	15,896	20,804	24,119	23,675	23,427	28,714	23,902	18,547	18,547	18,547	23,359	253,875
	8 Arsenic Groundwater Standard - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
	9 Sea Turtle - Coastal Street Lighting - Distrib	416	416	416	416	416	416	416	416	416	416	416	416	4,992
	11 Modular Cooling Towers - Base	0	0	0	0	0	0	0	0	0	0	0	0	0
	12 Greenhouse Gas Inventory and Reporting - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	13 Mercury Total Daily Maximum Loads Monitoring - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	14 Hazardous Air Pollutants (HAPs) ICR Program - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	15 Effluent Limitation Guidelines ICR Program - Energy	0	0	0	0	0	0	0	0	0	0	0	0	0
	16 Nat. Pollutant Discharge Elimination Sys. (NPDES)-Energy	2,000	63,000	83,000	67,000	63,000	49,500	30,000	15,000	75,500	77,500	75,000	47,500	648,000
	17 Maximum Achievable Control Technology (MACT)-Energy	50,000	50,000	50,000	50,000	75,000	25,000	0	0	0	0	0	0	300,000
2	Total of O&M Activities	3,672,980	3,714,445	4,355,567	3,733,097	3,950,406	3,748,368	3,777,421	4,114,219	3,896,908	3,115,691	3,864,753	4,476,965	46,420,819
3	Recoverable Costs Allocated to Energy	2,268,872	2,208,700	2,435,770	2,126,952	2,373,814	2,337,586	2,420,833	2,425,665	2,360,447	1,357,284	1,804,989	2,610,038	26,730,951
4	Recoverable Costs Allocated to Demand - Transm	165,997	165,997	165,997	165,997	165,997	165,997	165,997	165,997	165,997	165,997	165,997	165,997	1,991,964
	Recoverable Costs Allocated to Demand - Distrib	175,392	175,392	195,392	175,392	175,392	175,392	175,392	175,392	195,392	466,392	175,392	175,392	2,435,704
	Recoverable Costs Allocated to Demand - Prod-Base	862,800	957,376	1,366,520	1,074,554	1,045,445	974,883	920,402	1,257,179	1,010,441	966,388	1,537,144	1,426,492	13,399,625
	Recoverable Costs Allocated to Demand - Prod-Intm	166,083	166,083	166,083	166,083	166,083	66,083	66,083	66,083	141,083	141,083	141,083	66,087	1,518,000
	Recoverable Costs Allocated to Demand - Prod-Peaking	19,500	25,000	5,000	0	0	5,000	0	0	5,000	0	21,600	9,600	90,700
	Recoverable Costs Allocated to Demand - A&G	14,336	15,896	20,804	24,119	23,675	23,427	28,714	23,902	18,547	18,547	18,547	23,359	253,875
5	Retail Energy Jurisdictional Factor	0.98770	0.97210	0.97650	0.97800	0.97820	0.97850	0.97700	0.97590	0.97460	0.97390	0.97450	0.97730	
6	Retail Transmission Demand Jurisdictional Factor	0.69516	0.69516	0.69516	0.69516	0.69516	0.69516	0.69516	0.69516	0.69516	0.69516	0.69516	0.69516	
	Retail Distribution Demand Jurisdictional Factor	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	
	Retail Production Demand Jurisdictional Factor - Base	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	
	Retail Production Demand Jurisdictional Factor - Intm	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	
	Retail Production Demand Jurisdictional Factor - Peaking	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	
	Retail Production Demand Jurisdictional Factor - A&G	0.92374	0.92374	0.92374	0.92374	0.92374	0.92374	0.92374	0.92374	0.92374	0.92374	0.92374	0.92374	
7	Jurisdictional Energy Recoverable Costs (A)	2,240,965	2,147,078	2,378,530	2,080,159	2,322,065	2,287,328	2,365,154	2,367,206	2,300,492	1,321,859	1,758,962	2,550,790	26,120,588
8	Jurisdictional Demand Recoverable Costs - Transm (B)	115,394	115,394	115,394	115,394	115,394	115,394	115,394	115,394	115,394	115,394	115,394	115,394	1,384,728
	Jurisdictional Demand Recoverable Costs - Distrib (B)	174,733	174,733	194,657	174,733	174,733	174,733	174,733	174,733	194,657	464,638	174,733	174,733	2,426,549
	Jurisdictional Demand Recoverable Costs - Prod-Base (B)	800,609	888,368	1,268,021	997,100	970,089	904,614	854,059	1,166,562	937,609	896,731	1,426,347	1,323,671	12,433,780
	Jurisdictional Demand Recoverable Costs - Prod-Intm (B)	120,478	120,478	120,478	120,478	120,478	47,937	47,937	47,937	102,343	102,343	102,343	47,940	1,101,170
	Jurisdictional Demand Recoverable Costs - Prod-Peaking (B)	17,935	22,993	4,599	0	0	4,599	0	0	4,599	0	19,866	8,829	83,420
	Jurisdictional Demand Recoverable Costs - A&G (B)	13,243	14,684	19,218	22,280	21,869	21,640	26,524	22,080	17,133	17,133	17,133	21,577	234,515
9	Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 3,483,357	$ 3,483,728	$ 4,100,897	$ 3,510,144	$ 3,724,628	$ 3,556,245	$ 3,583,801	$ 3,893,912	$ 3,672,227	$ 2,918,098	$ 3,614,778	$ 4,242,934	$ 43,784,750

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

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2012 - DECEMBER 2012
Capital Investment Projects-Recoverable Costs
(in Dollars)

Line	Description	Projected Jan - 12	Projected Feb - 12	Projected Mar - 12	Projected Apr - 12	Projected May - 12	Projected Jun - 12	Projected Jul - 12	Projected Aug - 12	Projected Sep - 12	Projected Oct - 12	Projected Nov - 12	Projected Dec - 12	End of Period Total
1	Description of Investment Projects (A)													
3.1	Pipeline Integrity Management - Bartow/Anclote Pipeline-Intermediate	$ 38,028	$ 37,954	$ 37,679	$ 37,805	$ 37,731	$ 37,658	$ 37,583	$ 37,510	$ 37,436	$ 37,361	$ 37,285	$ 37,212	$ 451,442
4.1	Above Ground Tank Secondary Containment - Peaking	140,364	140,051	139,737	139,423	139,112	138,799	138,487	138,174	137,860	137,548	137,235	136,924	1,663,714
4.2	Above Ground Tank Secondary Containment - Base	32,345	32,292	32,236	32,180	32,125	32,070	32,015	31,959	31,903	31,849	31,794	31,738	384,506
4.3	Above Ground Tank Secondary Containment - Intermediate	3,058	3,054	3,049	3,045	3,039	3,034	3,030	3,024	3,020	3,015	3,010	3,005	36,383
5	SO2 & NOX Emissions Allowances - Energy	234,764	229,292	223,790	218,264	212,704	207,065	201,397	195,710	190,045	184,427	178,814	173,190	2,449,462
7.1	CAIR Anclote- Intermediate	0	0	0	0	0	0	0	0	0	0	0	0	0
7.2	CAIR CT's - Peaking	21,092	21,057	21,025	20,994	20,962	20,929	20,898	20,864	20,832	20,800	20,768	20,734	[illegible]
7.3	CAIR Crystal River - Base	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	2,644	[illegible]
7.4	CAIR Crystal River AFUDC - Base	14,241,599	14,225,042	14,201,549	14,191,474	14,213,641	14,250,578	14,249,116	14,225,446	14,201,781	14,193,357	14,203,902	14,246,224	170,643,709
7.4	CAIR Crystal River - Energy	5,408	5,408	5,408	5,408	5,408	5,408	5,408	5,408	5,408	5,408	5,408	5,408	64,897
9	Sea Turtle - Coastal Street Lighting -Distribution	142	142	142	142	142	141	141	141	141	141	141	139	1,695
10.1	Underground Storage Tanks-Base	1,757	1,755	1,752	1,749	1,746	1,744	1,741	1,738	1,735	1,733	1,730	1,727	20,907
10.2	Underground Storage Tanks-Intermediate	846	845	842	841	839	837	835	834	831	830	827	826	10,033
11	Modular Cooling Towers - Base	438	438	438	438	438	438	438	438	438	438	438	438	5,256
11.1	Crystal River Thermal Discharge Compliance Project AFUDC - Base	3,978	3,974	3,970	3,964	3,960	3,955	3,951	3,946	3,941	3,937	3,932	3,927	47,435
16	National Pollutant Discharge Elimination System (NPDES)-Intermediate	148	5,562	11,844	14,551	17,454	19,411	20,201	20,292	20,383	20,472	20,561	20,646	191,525
2	Total Investment Projects - Recoverable Costs	14,726,611	14,709,510	14,686,305	14,672,922	14,691,945	14,724,711	14,717,885	14,688,128	14,658,398	14,643,960	14,648,489	14,684,782	176,253,647
3	Recoverable Costs Allocated to Energy	240,172	234,700	229,198	223,672	218,112	212,473	206,805	201,118	195,453	189,835	184,222	178,598	2,514,359
4	Recoverable Costs Allocated to Demand - Distribution	142	142	142	142	142	141	141	141	141	141	141	139	1,695
	Recoverable Costs Allocated to Demand - Production - Base	14,282,761	14,266,145	14,242,589	14,232,449	14,254,554	14,291,429	14,289,905	14,266,171	14,242,442	14,233,958	14,244,440	14,286,698	171,133,541
	Recoverable Costs Allocated to Demand - Production - Intermediate	42,080	47,415	53,614	56,242	59,063	60,940	61,649	61,660	61,670	61,678	61,683	61,689	689,383
	Recoverable Costs Allocated to Demand - Production - Peaking	161,456	161,108	160,762	160,417	160,074	159,728	159,385	159,038	158,692	158,348	158,003	157,658	1,914,669
5	Retail Energy Jurisdictional Factor	0.98770	0.97210	0.97650	0.97800	0.97820	0.97850	0.97700	0.97590	0.97460	0.97390	0.97450	0.97730	
6	Retail Distribution Demand Jurisdictional Factor	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	0.99624	
	Retail Demand Jurisdictional Factor - Production - Base	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	0.92792	
	Retail Demand Jurisdictional Factor - Production - Intermediate	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	0.72541	
	Retail Demand Jurisdictional Factor - Production - Peaking	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	0.91972	
7	Jurisdictional Energy Recoverable Costs (B)	237,218	228,152	223,812	218,751	213,357	207,905	202,049	196,271	190,489	184,880	179,524	174,544	2,456,953
8	Jurisdictional Demand Recoverable Costs - Distribution (C)	141	141	141	141	141	140	140	140	140	140	140	138	[illegible]
	Jurisdictional Demand Recoverable Costs - Production - Base (C)	13,253,260	13,237,841	13,215,983	13,206,574	13,227,086	13,261,303	13,259,889	13,237,865	13,215,847	13,207,974	13,217,701	13,256,913	[illegible]
	Jurisdictional Demand Recoverable Costs - Production - Intermediate (C)	30,525	34,395	38,892	40,799	42,845	44,206	44,721	44,729	44,736	44,742	44,745	44,750	500,085
	Jurisdictional Demand Recoverable Costs - Production - Peaking (C)	148,494	148,174	147,856	147,539	147,223	146,905	146,590	146,270	145,952	145,636	145,319	145,001	1,760,959
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 13,669,639	$ 13,648,704	$ 13,626,685	$ 13,613,804	$ 13,630,653	$ 13,660,460	$ 13,653,388	$ 13,625,276	$ 13,597,164	$ 13,583,373	$ 13,587,430	$ 13,621,346	$ 163,517,921

Notes:
(A) Each project's Total System Recoverable Expenses on Form 42-4P, Line 9; Line 5 for Project 5 - Allowances and Project 7.4 - Reagents
(B) Line 3 x Line 5
(C) Line 4 x Line 6

Docket No. 110007-EI
Progress Energy Florida
Witness: T.G. Foster
Exhibit No.__(TGF-3)
Page 3 of 40

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of the Projected Period Amount
JANUARY 2012 - DECEMBER 2012
Schedule of Amortization and Return
Deferred Gain on Sales of Emissions Allowances (Project 5)
(in Dollars)

Line	Description		Beginning of Period Amount	Projected Jan - 12	Projected Feb - 12	Projected Mar - 12	Projected Apr - 12	Projected May - 12	Projected Jun - 12	Projected Jul - 12	Projected Aug - 12	Projected Sep - 12	Projected Oct - 12	Projected Nov - 12	Projected Dec - 12	End of Period Total
1	Working Capital Dr (Cr)															
	a. 1581001 SO_2 Emission Allowance Inventory		$ 4,972,187	$ 4,954,700	$ 4,943,169	$ 4,919,212	$ 4,905,326	$ 4,873,762	$ 4,838,797	$ 4,800,928	$ 4,762,130	$ 4,728,719	$ 4,700,192	$ 4,668,241	$ 4,636,979	$ 4,636,979
	b. 25401FL Auctioned SO_2 Allowance		(1,554,395)	(1,511,726)	(1,469,057)	(1,426,388)	(1,386,941)	(1,343,869)	(1,300,798)	(1,257,726)	(1,214,655)	(1,171,583)	(1,128,512)	(1,085,440)	(1,042,369)	(1,042,369)
	c. 1581002 NO_x Emission Allowance Inventory		0	0	0	0	0	0	0	0	0	0	0	0	0	0
	d. 1823403 NO_x Emission Allowance Regulatory Asset (A)		22,549,875	21,923,489	21,297,104	20,670,719	20,044,333	19,417,948	18,791,562	18,165,177	17,538,792	16,912,406	16,286,021	15,659,635	15,033,250	15,033,250
2	Total Working Capital		25,967,667	25,366,463	24,771,236	24,163,542	23,562,718	22,947,870	22,329,561	21,708,380	21,086,267	20,469,542	19,857,701	19,242,436	18,627,860	18,627,860
3	Average Net Investment			25,667,065	25,068,850	24,467,389	23,863,130	23,255,294	22,638,716	22,018,971	21,397,323	20,777,904	20,163,621	19,550,068	18,935,148	
4	Return on Average Net Working Capital Balance (B)															
	a. Equity Component Grossed Up For Taxes	8.02%		171,615	167,615	163,593	159,553	155,489	151,367	147,223	143,066	138,925	134,818	130,715	126,604	1,790,583
	b. Debt Component (Line 6 x Rate x 1/12)	2.95%		63,149	61,677	60,197	58,711	57,215	55,698	54,174	52,644	51,120	49,609	48,099	46,586	658,879
5	Total Return Component (C)			234,764	229,292	223,790	218,264	212,704	207,065	201,397	195,710	190,045	184,427	178,814	173,190	2,449,462
6	Expense Dr (Cr)															
	a. 5090001 SO_2 Allowance Expense			17,487	11,511	23,977	13,886	31,534	34,995	37,868	38,799	33,411	28,527	31,951	31,262	335,208
	b. 4074004 SO_2 Allowance Amortization Expense			(42,669)	(42,669)	(42,669)	(44,279)	(43,071)	(43,071)	(43,071)	(43,071)	(43,071)	(43,071)	(43,071)	(43,071)	(516,858)
	c. 5091003 NO_x Allowance Expense			626,385	626,385	626,385	626,385	626,385	626,385	626,385	626,385	626,385	626,385	626,385	626,385	7,516,625
7	Net Expense (D)			601,203	595,228	607,694	595,992	614,848	618,309	621,182	622,113	616,725	611,841	615,265	614,576	7,334,975
8	Total System Recoverable Expenses (Lines 5 + 7)			835,967	824,520	831,484	814,256	827,552	825,374	822,579	817,823	806,770	796,268	794,079	787,766	9,784,437
	a. Recoverable costs allocated to Energy			835,967	824,520	831,484	814,256	827,552	825,374	822,579	817,823	806,770	796,268	794,079	787,766	9,784,437
	b. Recoverable costs allocated to Demand			0	0	0	0	0	0	0	0	0	0	0	0	0
9	Energy Jurisdictional Factor			0.98770	0.97210	0.97650	0.97800	0.97820	0.97850	0.97700	0.97590	0.97460	0.97390	0.97450	0.97730	
10	Demand Jurisdictional Factor			N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	
11	Retail Energy-Related Recoverable Costs (E)			825,685	801,516	811,944	796,343	809,511	807,628	803,659	798,113	786,278	775,486	773,830	769,884	9,559,876
12	Retail Demand-Related Recoverable Costs (F)			0	0	0	0	0	0	0	0	0	0	0	0	0
13	Total Jurisdictional Recoverable Costs (Lines 11 + 12)			$ 825,685	$ 801,516	$ 811,944	$ 796,343	$ 809,511	$ 807,628	$ 803,659	$ 798,113	$ 786,278	$ 775,486	$ 773,830	$ 769,884	$ 9,559,876

Notes:
(A) As further described in the testimony of witnesses West and Foster, PEF expects the Cross-State Air Polution Rule (CSAPR) to impact the value of NOx allowances not used in 2011. PEF is reflecting the CSAPR impact by moving this investment to a regulatory asset to be amortized into rates over a 3 year period and be fully recovered by year end 2014.
(B) Line 3 x 10.98% x 1/12. Based on ROE of 10.5%, weighted cost of equity component of capital structure of 4.93%, and statutory income tax rate of 38.575% (expansion factor of 1.628002). Based on 2010 rate case Order PSC-10-0131-FOF-EI
(C) Line 5 is reported on Capital Schedule
(D) Line 7 is reported on O&M Schedule
(E) Line 8a x Line 9.
(F) Line 8b x Line 10.

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
JANUARY 2012 - DECEMBER 2012
Description and Progress Report for
Environmental Compliance Activities and Projects

Project Title: **SO_2 and NOx Emissions**
Project No. 5

Project Description:
In accordance with Title IV of the Clean Air Act, CFR 40 Part 73 and Part 76, and Florida Administrative Code Rule 62-214 and the Clean Air Interstate Rule, PEF manages SO_2 and NOx emissions allowance inventory for the purpose of offsetting sulfur dioxide and nitrogen oxides emissions in compliance with the Federal Acid Rain Program. On 7/6/11, the EPA issued the Cross-State Air Pollution Rule (CSAPR) which serves as a replacement rule to CAIR. CSAPR significantly alters SO2 and NOx allowance programs. Under CAIR, Florida is required to comply with annual SO2 and NOx emission requirements and seasonal requirements regulating NOx emissions during the ozone season. Under CSAPR, Florida is no longer included in the group of states required to comply with annual emissions requirements. It is only covered by the ozone season portions of the CSAPR rule. CSAPR replaces CAIR starting 1/1/12. The effective compliance date for Florida is 5/1/12 (beginning of the ozone season). Further discussion of CSAPR is included in the testimony of Patricia Q. West.

Project Accomplishments:

For purposes of compliance with an affected unit's sulfur dioxide (SO_2) and nitrogen oxides (NO_X emissions requirements under the Acid Rain Program, air quality compliance costs are administered by an authorized account representative who evaluates a variety of resources and options. Activities performed include purchases of SO_2 and NO_X emissions allowances as well as auctions and transfers of SO_2 emissions allowances. Under the new CSAPR rule , emission allowances previously issued to utility companies under the Acid Rain Program have no value as of 1/1/12. Any NO_X allowances issued under the Acid Rain Program not used by the end of 2011 are not expected to be useful for compliance with the CSAPR rule. As such, PEF has reflected movement of these capital investments from the NO_X allowance inventory to a regulatory asset to be recovered in rates in 2012. SO_2 allowances will still have value under the existing acid rain program requirements.

Project Fiscal Expenditures:
January 1, 2011 to December 31, 2011: Project expenditures are estimated to be approximately $0.3 million lower than originally projected. This variance is primarily driven by lower than anticipated NO_X allowance prices partially offset by higher than projected NO_X allowance usage.

Project Progress Summary:
PEF continually evaluates its compliance strategy to manage the most cost effective program and to mitigate higher gas prices which can impact the fuel mix as it relates to emissions as a result of residual oil.

Project Projections:
For the period January 2012 through December 2012 SO_2 expenditures are expected to be approximately $0.3 million. NO_X expenses under the new seasonal program cannot be projected at this time, however PEF is reflecting approximately $7.5 million in amortization of the 2011 estimated year end NO_X allowance balance due to the discontinuation of the existing program.

Revised Form 42-7P

PROGRESS ENERGY FLORIDA
Environmental Cost Recovery Clause (ECRC)
Calculation of Environmental Cost Recovery Clause Rate Factors by Rate Class
JANUARY 2012 - DECEMBER 2012

Rate Class		(1) mWh Sales at Source Energy Allocator (%)	(2) 12CP Transmission Demand Allocator (%)	(3) 12CP & 1/13th AD Demand Allocator (%)	(4) NCP Distribution Allocator (%)	(5) Energy-Related Costs ($)	(6) Transmission Demand Costs ($)	(7) Distribution Demand Costs ($)	(8) Production Demand Costs ($)	(9) Total Environmental Costs ($)	(10) Projected Effective Sales at Meter Level (mWh)	(11) Environmental Cost Recovery Factors (cents/kWh)
Residential												
RS-1, RST-1, RSL-1, RSL-2, RSS-1												
	Secondary	50.602%	62.710%	61.779%	63.663%	$97,056,294	$2,398,376	$1,430,396	$484,322	$101,369,389	18,600,869	0.545
General Service Non-Demand												
GS-1, GST-1												
	Secondary										1,209,225	0.539
	Primary										5,940	0.534
	Transmission										4,255	0.528
	TOTAL GS	3.317%	2.922%	2.952%	3.549%	$6,361,459	$111,736	$79,740	$23,142	$6,576,077	1,219,420	
General Service												
GS-2	Secondary	0.327%	0.200%	0.210%	0.149%	$627,325	$7,658	$3,338	$1,646	$639,967	120,227	0.532
General Service Demand												
GSD-1, GSDT-1, SS-1												
	Secondary										12,082,271	0.534
	Primary										2,280,315	0.529
	Transmission										9,192	0.523
	TOTAL GSD	38.948%	30.363%	31.023%	28.881%	$74,703,564	$1,161,228	$648,898	$243,208	$76,756,898	14,371,778	
Curtailable												
CS-1, CST-1, CS-2, CST-2, CS-3, CST-3, SS-3												
	Secondary										-	0.528
	Primary										159,935	0.523
	Transmission										-	0.517
	TOTAL CS	0.425%	0.309%	0.318%	0.716%	$814,532	$11,813	$16,083	$2,491	$844,919	159,935	
Interruptible												
IS-1, IST-1, IS-2, IST-2, SS-2												
	Secondary										109,609	0.520
	Primary										1,501,477	0.515
	Transmission										422,008	0.510
	TOTAL IS	5.405%	3.380%	3.536%	2.117%	$10,367,851	$129,283	$47,561	$27,722	$10,572,417	2,033,093	
Lighting												
LS-1	Secondary	0.977%	0.116%	0.182%	0.926%	$1,874,075	$4,441	$20,816	$1,430	$1,900,761	359,167	0.529
		100.000%	100.000%	100.000%	100.000%	$191,805,099	$3,824,535	$2,246,832	$783,962	$198,660,428	36,864,489	0.539

Notes:

Notes:	(1)	From Form 42-6P, Column 9
	(2)	From Form 42-6P, Column 10
	(3)	From Form 42-6P, Column 11
	(4)	From Form 42-6P, Column 12
	(5)	Column 1 x Total Energy Jurisdictional Dollars from Form 42-1P, line 5
	(6)	Column 2 x Total Transmission Demand Jurisdictional Dollars from Form 42-1P, line 5
	(7)	Column 4 x Total Distribution Demand Jurisdictional Dollars from Form 42-1P, line 5
	(8)	Column 3 x Total Production Demand Jurisdictional Dollars from Form 42-1P, line 5
	(9)	Column 5 + Column 6 + Column 7 + Column 8
	(10)	Projected kWh sales at secondary voltage level for the period January 2012 to December 2012
	(11)	(Column 9/ Column 10)/10

Attachment B

REVIESIONS TO TESTIMONY OF THOMAS G. FOSTER ORIGINALLY FILED ON AUGUST 26, 2011		
PAGE/LINE	**REIVISION**	**REASON FOR CHANGE**
1/2	Add "REVISED" before "DIRECT"	Denote this is revised testimony.
1/7	Strike "August 26" and replace with "October 14"	Update date filed.
3/8	Strike "212.5" replace with "198.7"	Change revenue requirements consistent with 3 year amortization of Nox allowance balance and errata corrections.
7/11	Strike "2012" replace with "three years from 2012-2014" and strike "The" replace with "One third of the"	Change language to be consistent with 3 year amortization of Nox allowance balance.
7/12	Strike "until"	Change language to be consistent with 3 year amortization of Nox allowance balance.
7/12	Strike "completely recovered at year end."	Change language to be consistent with 3 year amortization of Nox allowance balance.
7/18	After the word "balance," add "based on allowance usage, one third of"	Change language to be consistent with 3 year amortization of Nox allowance balance.
7/19	After the word "amortized" add "in 2012"	Change language to be consistent with 3 year amortization of Nox allowance balance.
8/3	Strike "58.5" and replace with "43.8"	Change revenue requirements consistent with 3 year amortization of Nox allowance balance and errata corrections.
8/9	Strike "162.7" and replace with "163.5"	Change revenue requirements consistent with 3 year amortization of Nox allowance balance and errata corrections.
8/19	Strike "221.2" replace with "207.3"	Change revenue requirements consistent with 3 year amortization of Nox allowance balance and errata corrections.
10	ECRC Factors Column	Change ECRC factors based on updated revenue requirements in the following table.
11/9	Strike "0.577" replace with "0.539"	Change ECRC factor based on updated revenue requirements.
11/10	Strike "221.2" replace with "207.3"	Change revenue requirements consistent with 3 year amortization of Nox allowance balance and errata corrections.

ATTACHMENT B
(Continued)

RATE CLASS	ECRC FACTORS 12CP & 1/13AD
Residential	0.545 cents/kWh
General Service Non-Demand	
@ Secondary Voltage	0.539 cents/kWh
@ Primary Voltage	0.534 cents/kWh
@ Transmission Voltage	0.528 cents/kWh
General Service 100% Load Factor	0.532 cents/kWh
General Service Demand	
@ Secondary Voltage	0.534 cents/kWh
@ Primary Voltage	0.529 cents/kWh
@ Transmission Voltage	0.523 cents/kWh
Curtailable	
@ Secondary Voltage	0.528 cents/kWh
@ Primary Voltage	0.523 cents/kWh
@ Transmission Voltage	0.517 cents/kWh
Interruptible	
@ Secondary Voltage	0.520 cents/kWh
@ Primary Voltage	0.515 cents/kWh
@ Transmission Voltage	0.510 cents/kWh
Lighting	0.529 cents/kWh

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BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Environmental cost recovery clause.	DOCKET NO. 110007-EI DATED: OCTOBER 25, 2011

PROGRESS ENERGY FLORIDA'S REVISED RESPONSE TO THE FLORIDA INDUSTRIAL POWER USERS GROUP'S THIRD SET OF INTERROGATORIES (NO. 6)

PROGRESS ENERGY FLORIDA, INC. ("PEF"), pursuant to Rule 28-106.206, Florida Administrative Code, Rule 1.340, Florida Rules of Civil Procedure, and the Order Establishing Procedure in this matter, hereby revises its response to the Florida Industrial Power Users Group's (FIPUG) Third Set of Interrogatories (No. 6):

RESPONSE

6. **For all environmental costs related to replacement power purchased or projected to be purchased due to the CR3 outage, provide the amounts PEF is seeking to recover for each category below in the 2012 factor:**

a. Final cost recovery true-up amount for the period ending December 31, 2010;

Answer:

No allowance purchases have been made associated with replacement power due to the CR3 outage. PEF has made no allowance purchases since May of 2009. Please see below for estimated system expense associated with previously purchased allowances related to replacement power due to the CR3 outage included in PEF's projected 2012 factor.

2010	$ 2,453,542
2011	1,191,999
2012	(957,130)
Total	$ 2,688,411

** Revised to reflect PEF's agreement with Staff Position on issue 10e to amortize the NOx allowance regulatory asset over 3 years rather than one year.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 110007-EI EXHIBIT 41
PARTY FLORIDA INDUSTRIAL POWER USERS
DESCRIPTION REVISED RESPONSE TO 3RD SET OF IROGS
DATE 11/2/11

b. Estimated true-up amount for the period January 2011-December 2011;

Answer:

Please see response to 6a above.

c. Projected true-up amount for January 2012-December 2012.

Answer:

Please see response to 6a above.

DATED this 25th day of October, 2011.

HOPPING GREEN & SAMS, P.A.

By: ______________________

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

Attorneys for Progress Energy Florida, Inc.

AFFIDAVIT

(STATE OF FLORIDA

COUNTY OF Pinellas)

I hereby certify that on this 25th day of October, 2011, before me, an officer duly authorized in the State and County aforesaid to take acknowledgments, personally appeared THOMAS G. FOSTER, who is personally known to me, and he acknowledged before me that he provided the answers to interrogatory number(s) 6a, b, and c from REVISED FIPUG'S THIRD SET OF INTERROGATORIES TO PROGRESS ENERGY FLORIDA, INC. (NO. 6a, b, and c) in Docket No. 110007-EI, and that the responses are true and correct based on his personal knowledge.

In Witness Whereof, I have hereunto set my hand and seal in the State and County aforesaid as of this 25th day of October, 2011.

Name

SUZANNE H. MILLER
MY COMMISSION # DD 842069
EXPIRES: March 27, 2013
Bonded Thru Notary Public Underwriters

Suzanne H. Miller
Notary Public
State of Florida

My Commission Expires:
3/27/13

FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 110007-EI **EXHIBIT** 42

PARTY FL Public Service Comm. Staff

DESCRIPTION Late Filed Exhibit

DATE 11/02/11