BEFORE THE
FLORIDA PUBLIC SERVICE COMMISSION

DOCKET NO. 040007-EI
FLORIDA POWER & LIGHT COMPANY

SEPTEMBER 9, 2004

ENVIRONMENTAL COST RECOVERY

PROJECTIONS
JANUARY 2005 THROUGH DECEMBER 2005

TESTIMONY & EXHIBITS OF:

K. M. DUBIN
R. R. LABAUVE

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF KOREL M. DUBIN

DOCKET NO. 040007-EI

SEPTEMBER 9, 2004

Q. Please state your name and address.

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

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

A. I am employed by Florida Power & Light Company (FPL) as Manager of Regulatory Issues in the Regulatory Affairs Department.

Q. Have you previously testified in this docket?

A. Yes, I have.

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

A. The purpose of my testimony is to present for Commission review FPL's Environmental Cost Recovery Clause (ECRC) projections for the January 2005 through December 2005 period.

Q. Is this filing by FPL in compliance with Order No. PSC-93-1580-FOF-

EI, issued in Docket No. 930661-EI?

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

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

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

Q. Please describe Form 42-1P.

A. Form 42-1P (Appendix I, Page 2) provides a summary of projected environmental costs being presented for the period January 2005 through December 2005. Total environmental costs, adjusted for revenue taxes, amount to $24,928,600 (Appendix I, Page 2, Line 5a) and include $24,476,832 of environmental project costs (Appendix I, Page 2, Line 1c) increased by the estimated/ actual under-recovery of $103,793 for the

January 2004 - December 2004 period as filed on August 4, 2004 (Appendix I, Page 2, Line 2) and decreased by the final over-recovery of $43,877 for the January 2003 – December 2003 period as filed on April 1, 2004 (Appendix I, Page 2, Line 3).

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

A. Form 42-2P (Appendix I, Pages 3 and 4) presents the environmental project O&M costs for the projected period along with the calculation of total jurisdictional costs for these projects, classified by energy and demand. Form 42-3P (Appendix I, Pages 5 and 6) presents the environmental project capital investment costs for the projected period. Consistent with FPL's 2002 Rate Agreement, FPL is using the 2002 capital cost and capital structure from the December, 2002 Surveillance Report to calculate the return on assets included in FPL's Environmental Cost Recovery Clause. Form 42-3P also provides the calculation of total jurisdictional costs for these projects, classified by energy and demand.

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

Q. Please describe Form 42-4P.

A. Form 42-4P (Appendix I, Pages 7 through 41) presents the calculation of depreciation expense and return on capital investment for each project for the projected period.

Q. Please describe Form 42-5P.

A. Form 42-5P (Appendix I, Pages 42 through 73) provides the description and progress of environmental projects included in the projected period.

Q. Please describe Form 42-6P.

A. Form 42-6P (Appendix I, Page 74) calculates the allocation factors for demand and energy at generation. The demand allocation factors are calculated by determining the percentage each rate class contributes to the monthly system peaks. The energy allocators are calculated by determining the percentage each rate contributes to total kWh sales, as adjusted for losses, for each rate class.

Q. Please describe Form 42-7P.

A. Form 42-7P (Appendix I, Page 75) presents the calculation of the proposed ECRC factors by rate class.

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

A. Yes, with the exception of the Selective Catalytic Reduction (SCR) Consumables Project and CWA 316(b) Phase II Rule Projects. The SCR Consumables Project is presented in the testimony of R. R. LaBauve which is being filed contemporaneously with my testimony. FPL filed for approval of the CWA 316(b) Phase II Rule Project on June 21, 2004. The

Commission is scheduled to address this project at the September 21, 2004 Agenda Conference. All of the projected costs for these projects in the projected period are O&M costs, so they are included on Schedule 42-3P as follows:

CWA 316(b) Phase II Rule	Project No. 28
SCR Consumables	Project No. 29

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

FLORIDA POWER & LIGHT COMPANY

TESTIMONY OF RANDALL R. LABAUVE

DOCKET NO. 040007-EI

September 9, 2004

Q. Please state your name and address.

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

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

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

Q. Have you testified in predecessors to this docket?

A. Yes.

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

A. The purpose of my testimony is to present for Commission review and approval FPL's plans for a new environmental project – the Selective Catalytic Reduction (SCR) Consumables Project.

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

supervision, or control, an exhibit in this proceeding?

A. Yes. It consists of the following documents:

- Document RRL-1 - Florida Power & Light Company Martin Unit 8 Power Plant Siting Application No. PA 89-27A - Final Order of Certification and excerpt from Conditions of Certification – Section IV - Air.

- Document RRL-2 - Florida Power & Light Company Manatee Unit 3 Power Plant Siting Application No. PA 02-44 - Final Order of Certification and excerpt from Conditions of Certification – Section XXIII - Air.

- Document RRL-3 - Drawing of a typical SCR module.

Q. **Please describe the law or regulation requiring the SCR Consumables Project.**

A. The Manatee Unit 3 and Martin Unit 8 Expansion Project Final Orders of Certification under the Florida Power Plant Siting Act and the Prevention of Significant Deterioration (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

US Environmental Protection Agency (EPA). As discussed below, operation of the SCRs requires FPL to incur O&M costs for certain products that are consumed in the SCRs.

Q. What alternatives to the installation of SCRs did FPL consider for Manatee Unit 3 and Martin Unit 8?

A. As part of the Best Available Control Technology (BACT) identification process with both FDEP and EPA, FPL was required to evaluate the various technologies available for NOx emission controls. In this determination the SCR system in combination with Dry Low NOx burners in the combustion turbines represent the best available control technology when considering engineering, the environment, and the economics. Other alternatives considered include other non-ammonia type catalytic, reactive, or absorption reactive processes. These alternatives were determined to be either technically and or economically not feasible by FDEP and EPA.

Q. Please describe the SCR system that is installed at Manatee Unit 3 and Martin Unit 8.

A. The SCR system is comprised of essentially two components. The first component is an array of porous catalyst material installed inside the Heat Recovery Steam Generator (HRSG), where all combustion exhaust flows through as it moves from the inlet duct to the exhaust stack. This array consists of 22 "blocks" that are placed into two columns of 11 blocks each. These blocks are impregnated with chemical elements that are needed to reduce the NO_X pollutants back to nitrogen and water vapor.

The second component consists of ammonia injection nozzles and associated piping. Anhydrous ammonia is blended with air and is injected upstream of the catalyst blocks through nozzles that are mounted through the sides of the HRSG. This ammonia mixes with the exhaust gases, and a chemical reduction reaction occurs on the surface of the catalyst.

Downstream of the SCR, located in the exhaust stack of the HRSG, Continuous Emissions Monitoring System (CEMS) equipment is mounted to continuously monitor the effectiveness of the SCRs. Per the Final Orders of Certification, NO_X concentrations in the exhaust are to be maintained at 2.5 parts per million. Additionally, the PSD Air Construction Permit limits the unreacted ammonia from the process, or slip target, to less than 5 parts per million, which is confirmed by annual stack testing conducted in accordance with the EPA.

Q. What O&M costs does FPL seek to recover through the SCR Consumables Project?

A. FPL is seeking recovery of O&M costs associated with consumable goods necessary to operate the SCR systems at Manatee Unit 3 and Martin Unit 8. 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.

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

A. The bulk supply and storage of anhydrous ammonia to each of the sites will be competitively bid with qualified suppliers to ensure a safe, reliable and least-cost supply. Additionally, the monitoring requirements previously discussed will help to ensure optimum injection rates of anhydrous ammonia in the SCR system, thus helping to minimize the consumption of anhydrous ammonia in the process.

Q. What are the compliance dates for this project?

A. The SCR systems are required to be operational whenever the units operate in the combined cycle mode. Manatee Unit 3 and Martin Unit 8 startup and commissioning is scheduled for early 2005. The expected commercial operation date for both Manatee Unit 3 and Martin Unit 8 is March 2005.

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

A. FPL has projected total annual O&M costs of $292,000 per plant, or a total of $584,000 for both plants, associated with the consumable goods necessary to operate the SCR systems at Manatee Unit 3 and Martin Unit 8. These O&M costs will begin once Manatee Unit 3 and Martin Unit 8 start commercial operations in March 2005 and the SCR systems become operational. The first full year of operation for both units will be 2006.

Q. Has FPL estimated how much will be spent on the Project in 2005?

A. FPL has projected O&M costs of $243,335 per plant, or a total of $486,670, associated with the consumable goods necessary to operate the SCR systems at Manatee Unit 3 and Martin Unit 8.

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

A. No.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX I

ENVIRONMENTAL COST RECOVERY
COMMISSION FORMS 42-1P THROUGH 42-7P

JANUARY 2005 – DECEMBER 2005
PROJECTIONS

KMD-3
DOCKET NO. 040007-EI
FPL WITNESS: K.M. DUBIN
EXHIBIT ______
PAGES 1-75

Form 42-1P

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

For the Projected Period
January 2005 to December 2005

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)	3,335,141	4,975,936	681,764	8,992,841
	b Projected Capital Projects (FORM 42-3P, Page 2 of 2, Lines 7 through 9)	11,027,258	4,456,733	0	15,483,991
	c Total Jurisdictional Rev. Req. for the projected period (Lines 1a + 1b)	14,362,399	9,432,669	681,764	24,476,832
2	True-up for Estimated Over/(Under) Recovery for the current period January 2004 - December 2004 (FORM 42-1E, Line 4, filed on August 4, 2004)	(53,852)	(43,075)	(6,865)	(103,793)
3	Final True-up Over/(Under) for the period January 2003 - December 2003 (FORM 42-1A, Line 7, filed on April 1, 2004)	26,983	12,640	4,254	43,877
4	Total Jurisdictional Amount to be Recovered/(Refunded) in the projection period January 2005 - December 2005 (Line 1 - Line 2 - Line 3)	14,389,268	9,463,104	684,375	24,536,748
5a	Total Projected Jurisdictional Amount Adjusted for Taxes (Line 4 x Revenue Tax Multiplier 1.01597)	14,619,065	9,614,230	695,304	24,928,600

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 Projected Period Amount
January 2005 - December 2005

O&M Activities
(in Dollars)

Line #	Project #		Projected JAN	Projected FEB	Projected MAR	Projected APR	Projected MAY	Projected JUN	6-Month Sub-Total
1		Description of O&M Activities							
	1	Air Operating Permit Fees-O&M	$159,067	$159,067	$159,067	$159,067	$159,067	$159,067	$954,402
	3a	Continuous Emission Monitoring Systems-O&M	59,323	59,323	59,323	59,323	59,323	59,323	355,938
	5a	Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	0	0	21,000	0	210,000	0	231,000
	8a	Oil Spill Cleanup/Response Equipment-O&M	13,833	13,833	13,833	13,833	13,833	13,833	82,998
	13	RCRA Corrective Action-O&M	0	0	25,000	0	0	25,000	50,000
	14	NPDES Permit Fees-O&M	156,400	0	0	0	0	0	156,400
	17a	Disposal of Noncontainerized Liquid Waste-O&M	19,667	19,667	38,667	19,000	29,667	10,667	137,335
	19a	Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	112,676	109,722	89,221	115,482	83,301	59,432	569,834
	19b	Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	113,716	110,722	84,721	119,782	88,101	68,232	585,274
	19c	Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(280,116)
	20	Wastewater Discharge Elimination &Reuse	0	0	0	0	0	0	0
	NA	Amortization of Gains on Sales of Emissions Allowances	(18,553)	(18,553)	(18,553)	(18,553)	(18,553)	(18,553)	(111,318)
	22	Pipeline Integrity Management	0	0	0	0	122,500	0	122,500
	23	SPCC - Spill Prevention, Control & Countermeasures	22,404	22,404	20,000	0	0	20,000	84,808
	26	UST Replacement/Removal	0	0	0	0	0	0	0
	27	Lowest Quality Water Source	31,500	31,500	31,500	31,500	31,500	31,500	189,000
	28	CWA 316(b) Phase II Rule	45,833	45,833	490,133	45,833	45,833	490,133	1,163,598
	29	SCR Consumables	0	0	48,667	48,667	48,667	48,667	194,668
2		Total of O&M Activities	$ 669,180	$ 506,832	$ 1,015,893	$ 547,248	$ 826,553	$ 920,615	$ 4,486,321
3		Recoverable Costs Allocated to Energy	$ 240,289	$ 240,058	$ 305,725	$ 288,755	$ 296,985	$ 276,457	$ 1,648,270
4a		Recoverable Costs Allocated to CP Demand	$ 339,558	$ 180,395	$ 644,290	$ 166,354	$ 469,610	$ 608,069	$ 2,408,275
4b		Recoverable Costs Allocated to GCP Demand	$ 89,333	$ 86,379	$ 65,878	$ 92,139	$ 59,958	$ 36,089	$ 429,776
5		Retail Energy Jurisdictional Factor	98.56595%	98.56595%	98.56595%	98.56595%	98.56595%	98.56595%	
6a		Retail CP Demand Jurisdictional Factor	98.63390%	98.63390%	98.63390%	98.63390%	98.63390%	98.63390%	
6b		Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	
7		Jurisdictional Energy Recoverable Costs (A)	$ 236,843	$ 236,616	$ 301,341	$ 284,614	$ 292,726	$ 272,492	$ 1,624,632
8a		Jurisdictional CP Demand Recoverable Costs (B)	$ 334,920	$ 177,930	$ 635,488	$ 164,081	$ 463,194	$ 599,762	$ 2,375,375
8b		Jurisdictional GCP Demand Recoverable Costs (C)	$ 89,333	$ 86,379	$ 65,878	$ 92,139	$ 59,958	$ 36,089	$ 429,776
9		Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 661,096	$ 500,925	$ 1,002,707	$ 540,834	$ 815,878	$ 908,343	$ 4,429,783

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 Projected Period Amount
January 2005 - December 2005

O&M Activities
(in Dollars)

Line # Project #	Projected JUL	Projected AUG	Projected SEP	Projected OCT	Projected NOV	Projected 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	$159,067	$159,067	$159,067	$159,067	$159,067	$159,067	$954,402	$1,908,804			$1,908,804
3a Continuous Emission Monitoring Systems-O&M	59,323	59,323	59,323	59,323	59,323	59,323	355,938	711,876			711,876
5a Maintenance of Stationary Above Ground Fuel Storage Tanks-O&M	217,000	0	0	0	0	0	217,000	448,000	448,000		
8a Oil Spill Cleanup/Response Equipment-O&M	13,833	13,833	13,833	13,833	13,833	13,833	82,998	165,996			165,996
13 RCRA Corrective Action-O&M	0	0	25,000	0	0	25,000	50,000	100,000	100,000		
14 NPDES Permit Fees-O&M	0	0	0	0	0	0	0	156,400	156,400		
17a Disposal of Noncontainerized Liquid Waste-O&M	21,667	22,000	29,333	29,333	18,333	11,000	131,666	269,001			269,001
19a Substation Pollutant Discharge Prevention & Removal - Distribution - O&M	62,701	62,677	62,601	66,882	72,716	64,469	392,046	961,880		961,880	
19b Substation Pollutant Discharge Prevention & Removal - Transmission - O&M	71,501	71,477	79,651	108,182	84,716	110,719	526,246	1,111,520	1,026,018		85,502
19c Substation Pollutant Discharge Prevention & Removal - Costs Included in Base Rates	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(46,686)	(280,116)	(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	(18,553)	(18,553)	(18,553)	(18,553)	(18,553)	(18,553)	(111,318)	(222,636)			(222,636)
22 Pipeline Integrity Management	52,500	0	0	0	0	0	52,500	175,000	175,000		
23 SPCC - Spill Prevention, Control & Countermeasures	0	0	20,000	0	0	20,000	40,000	124,808	124,808		
26 UST Replacement/Removal	0	0	284,000	0	0	284,000	568,000	568,000	568,000		
27 Lowest Quality Water Source	31,500	31,500	31,500	31,500	31,500	31,500	189,000	378,000	378,000		
28 CWA 316(b) Phase II Rule	45,833	45,833	490,133	45,833	45,833	490,133	1,163,598	2,327,196	2,327,196		
29 SCR Consumables	48,667	48,667	48,667	48,667	48,667	48,667	292,002	486,670			486,670
2 Total of O&M Activities	$ 718,353	$ 449,138	$1,237,869	$ 497,381	$ 468,749	$1,252,472	$ 4,623,962	$ 9,110,283	$ 5,044,853	$ 681,764	$3,383,666
3 Recoverable Costs Allocated to Energy	$ 287,708	$ 288,040	$ 296,001	$ 298,196	$ 285,391	$ 280,058	$ 1,735,395	$ 3,383,666			
4a Recoverable Costs Allocated to CP Demand	$ 391,287	$ 121,764	$ 902,610	$ 155,646	$ 133,985	$ 931,288	$ 2,636,579	$ 5,044,853			
4b Recoverable Costs Allocated to GCP Demand	$ 39,358	$ 39,334	$ 39,258	$ 43,539	$ 49,373	$ 41,126	$ 251,988	$ 681,764			
5 Retail Energy Jurisdictional Factor	98.56595%	98.56595%	98.56595%	98.56595%	98.56595%	98.56595%					
6a Retail CP Demand Jurisdictional Factor	98.63390%	98.63390%	98.63390%	98.63390%	98.63390%	98.63390%					
6b Retail GCP Demand Jurisdictional Factor	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%	100.00000%					
7 Jurisdictional Energy Recoverable Costs (A)	$ 283,583	$ 283,909	$ 291,757	$ 293,920	$ 281,298	$ 276,042	$ 1,710,509	$ 3,335,141			
8a Jurisdictional CP Demand Recoverable Costs (B)	$ 385,941	$ 120,101	$ 890,279	$ 153,520	$ 132,155	$ 918,565	$ 2,600,561	$ 4,975,936			
8b Jurisdictional GCP Demand Recoverable Costs (C)	$ 39,358	$ 39,334	$ 39,258	$ 43,539	$ 49,373	$ 41,126	$ 251,988	$ 681,764			
9 Total Jurisdictional Recoverable Costs for O&M Activities (Lines 7 + 8)	$ 708,882	$ 443,344	$1,221,294	$ 490,979	$ 462,826	$1,235,733	$ 4,563,058	$ 8,992,841			

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 Projected Period Amount
January 2005 - December 2005

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line # Project #		Projected JAN	Projected FEB	Projected MAR	Projected APR	Projected MAY	Projected JUN	6-Month Sub-Total
1	Description of Investment Projects (A)							
2	Low NOx Burner Technology-Capital	$ 165,304	$ 164,207	$ 163,109	$ 162,011	$ 160,914	$ 159,816	$ 975,361
3b	Continuous Emission Monitoring Systems-Capital	128,497	128,233	128,198	127,977	127,498	127,349	767,752
4b	Clean Closure Equivalency-Capital	526	524	521	519	516	514	3,120
5b	Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	159,395	159,006	158,617	158,227	157,838	157,449	950,532
7	Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	284	282	281	279	278	276	1,680
8b	Oil Spill Cleanup/Response Equipment-Capital	10,303	10,225	10,147	10,070	9,992	10,996	61,733
10	Relocate Storm Water Runoff-Capital	1,088	1,085	1,082	1,079	1,076	1,073	6,483
NA	SO2 Allowances-Negative Return on Investment	(14,756)	(14,574)	(14,393)	(14,211)	(17,492)	(20,773)	(96,199)
12	Scherer Discharge Pipeline-Capital	8,040	8,010	7,981	7,951	7,921	7,892	47,795
17b	Disposal of Noncontainerized Liquid Waste-Capital	0	0	0	0	0	0	0
20	Wastewater Discharge Elimination &Reuse	23,374	23,293	23,212	23,132	23,051	22,970	139,032
21	St. Lucie Turtle Net	8,310	8,289	8,267	8,245	8,224	8,202	49,537
22	Pipeline Integrity Management	3,541	3,531	3,520	3,509	3,498	3,487	21,086
23	SPCC - Spill Prevention, Control & Countermeasures	179,029	180,545	182,056	183,565	185,071	189,685	1,099,951
24	Manatee Reburn	114,607	123,819	131,629	139,316	147,003	147,023	803,397
25	Pt. Everglades ESP Technology	292,810	314,320	375,909	429,764	437,877	450,886	2,301,566
2	Total Investment Projects - Recoverable Costs	$ 1,080,352	$ 1,110,795	$ 1,180,136	$ 1,241,433	$ 1,253,265	$ 1,266,845	$ 7,132,826
3	Recoverable Costs Allocated to Energy	$ 716,761	$ 746,373	$ 814,889	$ 875,363	$ 886,374	$ 895,266	$ 4,935,027
4	Recoverable Costs Allocated to Demand	$ 363,591	$ 364,422	$ 365,247	$ 366,070	$ 366,891	$ 371,579	$ 2,197,799
5	Retail Energy Jurisdictional Factor	98.56595%	98.56595%	98.56595%	98.56595%	98.56595%	98.56595%	
6	Retail Demand Jurisdictional Factor	98.63390%	98.63390%	98.63390%	98.63390%	98.63390%	98.63390%	
7	Jurisdictional Energy Recoverable Costs (B)	$ 706,483	$ 735,670	$ 803,203	$ 862,810	$ 873,663	$ 882,427	$ 4,864,256
8	Jurisdictional Demand Recoverable Costs (C)	$ 358,624	$ 359,443	$ 360,257	$ 361,069	$ 361,879	$ 366,503	$ 2,167,775
9	Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 1,065,107	$ 1,095,113	$ 1,163,460	$ 1,223,879	$ 1,235,542	$ 1,248,930	$ 7,032,031

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

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Projected Period Amount
January 2005 - December 2005

Capital Investment Projects-Recoverable Costs
(in Dollars)

Line # Project #	Projected JUL	Projected AUG	Projected SEP	Projected OCT	Projected NOV	Projected 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	$ 158,718	$ 157,621	$ 156,523	$ 155,425	$ 154,328	$ 153,230	$ 935,845	$ 1,911,206		$ 1,911,206
3b Continuous Emission Monitoring Systems-Capital	126,578	126,036	125,494	125,504	125,847	125,541	755,000	$ 1,522,752		1,522,752
4b Clean Closure Equivalency-Capital	512	509	507	504	502	500	3,034	$ 6,154	5,681	473
5b Maintenance of Stationary Above Ground Fuel Storage Tanks-Capital	157,060	156,670	156,281	155,892	155,502	155,113	936,518	$ 1,887,050	1,741,892	145,158
7 Relocate Turbine Lube Oil Underground Piping to Above Ground-Capital	275	273	272	270	269	267	1,626	$ 3,306	3,052	254
8b Oil Spill Cleanup/Response Equipment-Capital	11,994	11,905	11,816	11,726	11,637	12,272	71,350	$ 133,083	122,846	10,237
10 Relocate Storm Water Runoff-Capital	1,069	1,066	1,063	1,060	1,057	1,054	6,369	$ 12,852	11,863	989
NA SO2 Allowances-Negative Return on Investment	(20,591)	(20,409)	(20,227)	(20,046)	(19,864)	(19,682)	(120,819)	$ (217,018)		(217,018)
12 Scherer Discharge Pipeline-Capital	7,862	7,832	7,803	7,773	7,743	7,714	46,727	$ 94,522	87,251	7,271
17b Disposal of Noncontainerized Liquid Waste-Capital	0	0	0	0	0	0	0	$	0	0
20 Wastewater Discharge Elimination &Reuse	22,889	22,808	22,727	22,646	22,565	24,216	137,851	$ 276,883	255,584	21,299
21 St. Lucie Turtle Net	8,180	8,159	8,137	8,115	8,094	8,072	48,757	$ 98,294	90,733	7,561
22 Pipeline Integrity Management	3,477	3,466	11,076	18,669	18,623	18,577	73,888	$ 94,974	87,668	7,306
23 SPCC - Spill Prevention, Control & Countermeasures	194,289	195,773	197,253	198,731	200,206	201,677	1,187,929	$ 2,287,880	2,111,889	175,991
24 Manatee Reburn	147,052	151,498	159,305	169,697	182,001	239,964	1,049,517	$ 1,852,914		1,852,914
25 Pt. Everglades ESP Technology	466,958	488,897	512,438	587,403	670,622	713,419	3,439,737	$ 5,741,303		5,741,303
2 Total Investment Projects - Recoverable Costs	$ 1,286,322	$ 1,312,104	$ 1,350,468	$ 1,443,369	$ 1,539,132	$ 1,641,934	$ 8,573,329	$ 15,706,155	$ 4,518,459	$ 11,187,696
3 Recoverable Costs Allocated to Energy	$ 910,069	$ 935,063	$ 965,605	$ 1,050,705	$ 1,145,718	$ 1,245,508	$ 6,252,668	$ 11,187,696		
4 Recoverable Costs Allocated to Demand	$ 376,253	$ 377,041	$ 384,863	$ 392,664	$ 393,414	$ 396,426	$ 2,320,661	$ 4,518,459		
5 Retail Energy Jurisdictional Factor	98.56595%	98.56595%	98.56595%	98.56595%	98.56595%	98.56595%				
6 Retail Demand Jurisdictional Factor	98.63390%	98.63390%	98.63390%	98.63390%	98.63390%	98.63390%				
7 Jurisdictional Energy Recoverable Costs (B)	$ 897,019	$ 921,654	$ 951,758	$ 1,035,637	$ 1,129,288	$ 1,227,646	$ 6,163,002	$ 11,027,258		
8 Jurisdictional Demand Recoverable Costs (C)	$ 371,113	$ 371,890	$ 379,605	$ 387,300	$ 388,039	$ 391,011	$ 2,288,958	$ 4,456,733		
9 Total Jurisdictional Recoverable Costs for Investment Projects (Lines 7 + 8)	$ 1,268,132	$ 1,293,544	$ 1,331,363	$ 1,422,937	$ 1,517,327	$ 1,618,657	$ 8,451,960	$ 15,483,991		

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

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period January through June 2005

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

Line		Beginning of Period Amount	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$17,611,468	17,611,468	17,611,468	17,611,468	17,611,468	17,611,468	17,611,468	n/a
3.	Less: Accumulated Depreciation (C)	12,121,440	12,233,532	12,345,623	12,457,715	12,569,807	12,681,899	12,793,991	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$5,490,028	$5,377,936	$5,265,845	$5,153,753	$5,041,661	$4,929,569	$4,817,477	n/a
6.	Average Net Investment		5,433,982	5,321,890	5,209,799	5,097,707	4,985,615	4,873,523	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		45,560	44,620	43,680	42,740	41,800	40,861	259,261
	b. Debt Component (Line 6 x 1.69% x 1/12)		7,653	7,495	7,337	7,179	7,021	6,864	43,549
8.	Investment Expenses								
	a. Depreciation (E)		112,092	112,092	112,092	112,092	112,092	112,092	672,551
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$165,304	$164,207	$163,109	$162,011	$160,914	$159,816	$975,361

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period July through December 2005

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

Line		Beginning of Period Amount	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$17,611,468	17,611,468	17,611,468	17,611,468	17,611,468	17,611,468	17,611,468	n/a
3.	Less: Accumulated Depreciation (C)	12,793,991	12,906,083	13,018,174	13,130,266	13,242,358	13,354,450	13,466,542	n/a
4.	CWIP - Non Interest Bearing	-	-						
5.	Net Investment (Lines 2 - 3 + 4)	$4,817,477	$4,705,385	$4,593,294	$4,481,202	$4,369,110	$4,257,018	$4,144,926	n/a
6.	Average Net Investment		4,761,431	4,649,340	4,537,248	4,425,156	4,313,064	4,200,972	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		39,921	38,981	38,041	37,101	36,162	35,222	484,689
	b. Debt Component (Line 6 x 1.69% x 1/12)		6,706	6,548	6,390	6,232	6,074	5,916	81,415
8.	Investment Expenses								
	a. Depreciation (E)		112,092	112,092	112,092	112,092	112,092	112,092	1,345,102
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$158,718	$157,621	$156,523	$155,425	$154,328	$153,230	$1,911,206

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

8

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period January through June 2005

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

Line		Beginning of Period Amount	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$22,000	$22,000	$55,000	$0	$22,000	$44,000	$165,000
	c. Retirements								$0
	d. Other (A)								$0
2.	Plant-In-Service/Depreciation Base (B)	$12,632,481	12,654,481	12,676,481	12,731,481	12,731,481	12,753,481	12,797,481	0
3.	Less: Accumulated Depreciation (C)	5,787,127	5,851,082	5,915,185	5,979,504	6,043,964	6,108,468	6,173,132	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$6,845,354	$6,803,399	$6,761,296	$6,751,976	$6,687,517	$6,645,013	$6,624,349	n/a
6.	Average Net Investment		6,824,376	6,782,348	6,756,636	6,719,747	6,666,265	6,634,681	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		57,217	56,865	56,649	56,340	55,891	55,627	338,588
	b. Debt Component (Line 6 x 1.69% x 1/12)		9,611	9,552	9,516	9,464	9,388	9,344	56,874
8.	Investment Expenses								
	a. Depreciation (E)		63,955	64,103	64,320	64,459	64,504	64,664	386,005
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)		(2,286)	(2,286)	(2,286)	(2,286)	(2,286)	(2,286)	(13,716)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$128,497	$128,233	$128,198	$127,977	$127,498	$127,349	$767,752

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) Monthly depreciation offset for base rate retirements.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period July through December 2005

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

Line		Beginning of Period Amount	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$11,000	$0	$88,000	$44,000	$0	$308,000
	c. Retirements								$0
	d. Other (A)								$0
2.	Plant-In-Service/Depreciation Base (B)	$12,797,481	12,797,481	12,808,481	12,808,481	12,896,481	12,940,481	12,940,481	n/a
3.	Less: Accumulated Depreciation (C)	6,173,132	6,237,913	6,302,731	6,367,589	6,432,661	6,498,070	6,563,598	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$6,624,349	$6,559,568	$6,505,750	$6,440,892	$6,463,820	$6,442,411	$6,376,883	n/a
6.	Average Net Investment		6,591,959	6,532,659	6,473,321	6,452,356	6,453,115	6,409,647	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		55,268	54,771	54,274	54,098	54,104	53,740	664,843
	b. Debt Component (Line 6 x 1.69% x 1/12)		9,284	9,200	9,117	9,087	9,088	9,027	111,677
8.	Investment Expenses								
	a. Depreciation (E)		64,780	64,819	64,857	65,073	65,408	65,528	776,471
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)		(2,754)	(2,754)	(2,754)	(2,754)	(2,754)	(2,754)	(30,240)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$126,578	$126,036	$125,494	$125,504	$125,847	$125,541	$1,522,752

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) Monthly depreciation offset for base rate retirements.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period January through June 2005

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

Line		Beginning of Period Amount	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$58,866	58,866	58,866	58,866	58,866	58,866	58,866	n/a
3.	Less: Accumulated Depreciation (C)	29,990	30,234	30,478	30,723	30,967	31,211	31,456	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$28,876	$28,632	$28,388	$28,143	$27,899	$27,655	$27,410	n/a
6.	Average Net Investment		28,754	28,510	28,265	28,021	27,777	27,532	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		241	239	237	235	233	231	1,416
	b. Debt Component (Line 6 x 1.69% x 1/12)		40	40	40	39	39	39	238
8.	Investment Expenses								
	a. Depreciation (E)		244	244	244	244	244	244	1,466
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$526	$524	$521	$519	$516	$514	$3,120

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period July through December 2005

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

Line		Beginning of Period Amount	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$58,866	58,866	58,866	58,866	58,866	58,866	58,866	n/a
3.	Less: Accumulated Depreciation (C)	31,456	31,700	31,944	32,189	32,433	32,677	32,922	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$27,410	$27,166	$26,922	$26,677	$26,433	$26,189	$25,944	n/a
6.	Average Net Investment		27,288	27,044	26,799	26,555	26,311	26,066	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		229	227	225	223	221	219	2,758
	b. Debt Component (Line 6 x 1.69% x 1/12)		38	38	38	37	37	37	463
8.	Investment Expenses								
	a. Depreciation (E)		244	244	244	244	244	244	2,932
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$512	$509	$507	$504	$502	$500	$6,154

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period January through June 2005

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 Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$14,053,123	14,053,123	14,053,123	14,053,123	14,053,123	14,053,123	14,053,123	n/a
3.	Less: Accumulated Depreciation (C)	1,750,075	1,789,827	1,829,579	1,869,332	1,909,084	1,948,836	1,988,589	n/a
4.	CWIP - Non Interest Bearing	-	-	-	-				
5.	Net Investment (Lines 2 - 3 + 4)	$12,303,048	$12,263,296	$12,223,544	$12,183,791	$12,144,039	$12,104,287	$12,064,534	n/a
6.	Average Net Investment		12,283,172	12,243,420	12,203,667	12,163,915	12,124,163	12,084,410	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		102,985	102,651	102,318	101,985	101,652	101,318	612,909
	b. Debt Component (Line 6 x 1.69% x 1/12)		17,299	17,243	17,187	17,131	17,075	17,019	102,953
8.	Investment Expenses								
	a. Depreciation (E)		39,752	39,752	39,752	39,752	39,752	39,752	238,514
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)		(641)	(641)	(641)	(641)	(641)	(641)	(3,843)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$159,395	$159,006	$158,617	$158,227	$157,838	$157,449	$950,532

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) Monthly depreciation offset for base rate retirements.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period July through December 2005

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 Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$14,053,123	14,053,123	14,053,123	14,053,123	14,053,123	14,053,123	14,053,123	n/a
3.	Less: Accumulated Depreciation (C)	1,988,589	2,028,341	2,068,093	2,107,846	2,147,598	2,187,350	2,227,103	n/a
4.	CWIP - Non Interest Bearing	-	-	-					
5.	Net Investment (Lines 2 - 3 + 4)	$12,064,534	$12,024,782	$11,985,030	$11,945,277	$11,905,525	$11,865,773	$11,826,020	n/a
6.	Average Net Investment		12,044,658	12,004,906	11,965,153	11,925,401	11,885,649	11,845,896	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		100,985	100,652	100,318	99,985	99,652	99,318	1,213,819
	b. Debt Component (Line 6 x 1.69% x 1/12)		16,963	16,907	16,851	16,795	16,739	16,683	203,891
8.	Investment Expenses								
	a. Depreciation (E)		39,752	39,752	39,752	39,752	39,752	39,752	477,028
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)		(641)	(641)	(641)	(641)	(641)	(641)	(7,687)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$157,060	$156,670	$156,281	$155,892	$155,502	$155,113	$1,887,050

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) Monthly depreciation offset for base rate retirements.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period January through June 2005

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 Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$31,030	31,030	31,030	31,030	31,030	31,030	31,030	n/a
3.	Less: Accumulated Depreciation (C)	17,579	17,731	17,884	18,036	18,189	18,342	18,494	n/a
4.	CWIP - Non Interest Bearing	-	-						
5.	Net Investment (Lines 2 - 3 + 4)	$13,451	$13,299	$13,146	$12,994	$12,841	$12,688	$12,536	n/a
6.	Average Net Investment		13,375	13,222	13,070	12,917	12,765	12,612	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		112	111	110	108	107	106	654
	b. Debt Component (Line 6 x 1.69% x 1/12)		19	19	18	18	18	18	110
8.	Investment Expenses								
	a. Depreciation (E)		153	153	153	153	153	153	915
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$284	$282	$281	$279	$278	$276	$1,680

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period July through December 2005

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 Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$31,030	31,030	31,030	31,030	31,030	31,030	31,030	n/a
3.	Less: Accumulated Depreciation (C)	18,494	18,647	18,799	18,952	19,104	19,257	19,409	n/a
4.	CWIP - Non Interest Bearing								
5.	Net Investment (Lines 2 - 3 + 4)	$12,536	$12,383	$12,231	$12,078	$11,926	$11,773	$11,621	n/a
6.	Average Net Investment		12,460	12,307	12,155	12,002	11,849	11,697	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		104	103	102	101	99	98	1,261
	b. Debt Component (Line 6 x 1.69% x 1/12)		18	17	17	17	17	16	212
8.	Investment Expenses								
	a. Depreciation (E)		153	153	153	153	153	153	1,831
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$275	$273	$272	$270	$269	$267	$3,306

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period January through June 2005

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 Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$100,000	$100,000
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$688,075	688,075	688,075	688,075	688,075	688,075	788,075	n/a
3.	Less: Accumulated Depreciation (C)	442,954	450,896	458,837	466,779	474,720	482,662	491,199	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$245,121	$237,179	$229,238	$221,296	$213,355	$205,413	$296,876	n/a
6.	Average Net Investment		241,150	233,208	225,267	217,325	209,384	251,145	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		2,022	1,955	1,889	1,822	1,756	2,106	11,549
	b. Debt Component (Line 6 x 1.69% x 1/12)		340	328	317	306	295	354	1,940
8.	Investment Expenses								
	a. Depreciation (E)		7,942	7,942	7,942	7,942	7,942	8,537	48,244
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$10,303	$10,225	$10,147	$10,070	$9,992	$10,996	$61,733

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period July through December 2005

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 Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0		$0	$0	$67,000	$167,000
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$788,075	788,075	788,075	788,075	788,075	788,075	855,075	n/a
3.	Less: Accumulated Depreciation (C)	491,199	500,331	509,463	518,595	527,727	536,859	546,390	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$296,876	$287,744	$278,612	$269,480	$260,348	$251,216	$308,685	n/a
6.	Average Net Investment		292,310	283,178	274,046	264,914	255,782	279,951	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		2,451	2,374	2,298	2,221	2,145	2,347	25,385
	b. Debt Component (Line 6 x 1.69% x 1/12)		412	399	386	373	360	394	4,264
8.	Investment Expenses								
	a. Depreciation (E)		9,132	9,132	9,132	9,132	9,132	9,531	103,435
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$11,994	$11,905	$11,816	$11,726	$11,637	$12,272	$133,083

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period January through June 2005

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

Line		Beginning of Period Amount	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$117,794	117,794	117,794	117,794	117,794	117,794	117,794	n/a
3.	Less: Accumulated Depreciation (C)	38,619	38,933	39,248	39,562	39,876	40,190	40,504	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$79,175	$78,861	$78,546	$78,232	$77,918	$77,604	$77,290	n/a
6.	Average Net Investment		79,018	78,704	78,389	78,075	77,761	77,447	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		663	660	657	655	652	649	3,935
	b. Debt Component (Line 6 x 1.69% x 1/12)		111	111	110	110	110	109	661
8.	Investment Expenses								
	a. Depreciation (E)		314	314	314	314	314	314	1,885
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,088	$1,085	$1,082	$1,079	$1,076	$1,073	$6,483

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period July through December 2005

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

Line		Beginning of Period Amount	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$117,794	117,794	117,794	117,794	117,794	117,794	117,794	n/a
3.	Less: Accumulated Depreciation (C)	40,504	40,818	41,132	41,446	41,760	42,075	42,389	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$77,290	$76,976	$76,662	$76,348	$76,034	$75,719	$75,405	n/a
6.	Average Net Investment		77,133	76,819	76,505	76,191	75,877	75,562	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		647	644	641	639	636	634	7,776
	b. Debt Component (Line 6 x 1.69% x 1/12)		109	108	108	107	107	106	1,306
8.	Investment Expenses								
	a. Depreciation (E)		314	314	314	314	314	314	3,769
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$1,069	$1,066	$1,063	$1,060	$1,057	$1,054	$12,852

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period January through June 2005

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

Line		Beginning of Period Amount	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$864,260	864,260	864,260	864,260	864,260	864,260	864,260	n/a
3.	Less: Accumulated Depreciation (C)	351,031	354,060	357,088	360,117	363,146	366,175	369,204	n/a
4.	CWIP - Non Interest Bearing								
5.	Net Investment (Lines 2 - 3 + 4)	$513,229	$510,200	$507,172	$504,143	$501,114	$498,085	$495,056	n/a
6.	Average Net Investment		511,715	508,686	505,657	502,628	499,599	496,570	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		4,290	4,265	4,240	4,214	4,189	4,163	25,361
	b. Debt Component (Line 6 x 1.69% x 1/12)		721	716	712	708	704	699	4,260
8.	Investment Expenses								
	a. Depreciation (E)		3,029	3,029	3,029	3,029	3,029	3,029	18,173
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$8,040	$8,010	$7,981	$7,951	$7,921	$7,892	$47,795

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period July through December 2005

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

Line		Beginning of Period Amount	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$864,260	864,260	864,260	864,260	864,260	864,260	864,260	n/a
3.	Less: Accumulated Depreciation (C)	369,204	372,233	375,262	378,291	381,320	384,348	387,377	n/a
4.	CWIP - Non Interest Bearing	-	-	-					
5.	Net Investment (Lines 2 - 3 + 4)	$495,056	$492,027	$488,998	$485,969	$482,940	$479,912	$476,883	n/a
6.	Average Net Investment		493,542	490,513	487,484	484,455	481,426	478,397	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		4,138	4,113	4,087	4,062	4,036	4,011	49,808
	b. Debt Component (Line 6 x 1.69% x 1/12)		695	691	687	682	678	674	8,366
8.	Investment Expenses								
	a. Depreciation (E)		3,029	3,029	3,029	3,029	3,029	3,029	36,347
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$7,862	$7,832	$7,803	$7,773	$7,743	$7,714	$94,522

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period January through June 2005

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

Line		Beginning of Period Amount	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.69% x 1/12)		0	0	0	0	0	0	0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period July through December 2005

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

Line		Beginning of Period Amount	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$0	$0	$0	$0	$0	$0	$0	n/a
6.	Average Net Investment		0	0	0	0	0	0	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		0	0	0	0	0	0	0
	b. Debt Component (Line 6 x 1.69% x 1/12)		0	0	0	0	0	0	0
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$0	$0	$0	$0	$0	$0	$0

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period January through June 2005

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

Line		Beginning of Period Amount	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$1,938,995	1,938,995	1,938,995	1,938,995	1,938,995	1,938,995	1,938,995	n/a
3.	Less: Accumulated Depreciation (C)	391,581	399,843	408,104	416,366	424,628	432,889	441,151	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$1,547,414	$1,539,152	$1,530,891	$1,522,629	$1,514,368	$1,506,106	$1,497,844	n/a
6.	Average Net Investment		1,543,283	1,535,021	1,526,760	1,518,498	1,510,237	1,501,975	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		12,939	12,870	12,801	12,731	12,662	12,593	76,596
	b. Debt Component (Line 6 x 1.69% x 1/12)		2,173	2,162	2,150	2,139	2,127	2,115	12,866
8.	Investment Expenses								
	a. Depreciation (E)		8,262	8,262	8,262	8,262	8,262	8,262	49,569
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$23,374	$23,293	$23,212	$23,132	$23,051	$22,970	$139,032

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

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Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period July through December 2005

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

Line		Beginning of Period Amount	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$250,000	$250,000
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$1,938,995	1,938,995	1,938,995	1,938,995	1,938,995	1,938,995	2,188,995	n/a
3.	Less: Accumulated Depreciation (C)	$441,151	449,412	457,674	465,935	474,197	482,458	491,230	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$1,497,844	$1,489,583	$1,481,321	$1,473,060	$1,464,798	$1,456,537	$1,697,765	n/a
6.	Average Net Investment		1,493,714	1,485,452	1,477,191	1,468,929	1,460,667	1,577,151	
7.	Return on Average Net Investment								
	Equity Component grossed up for taxes (D)		12,524	12,454	12,385	12,316	12,247	13,223	151,745
	Debt Component (Line 6 x 1.69% x 1/12)		2,104	2,092	2,080	2,069	2,057	2,221	25,489
8.	Investment Expenses								
	a. Depreciation (E)		8,262	8,262	8,262	8,262	8,262	8,772	99,649
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$22,889	$22,808	$22,727	$22,646	$22,565	$24,216	$276,883

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period January through June 2005

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

Line		Beginning of Period Amount	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$828,789	828,789	828,789	828,789	828,789	828,789	828,789	n/a
3.	Less: Accumulated Depreciation (C)	56,264	58,474	60,684	62,895	65,105	67,315	69,525	n/a
4.	CWIP - Non Interest Bearing								
5.	Net Investment (Lines 2 - 3 + 4)	$772,525	$770,315	$768,105	$765,895	$763,684	$761,474	$759,264	n/a
6.	Average Net Investment		771,420	769,210	767,000	764,789	762,579	760,369	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		6,468	6,449	6,431	6,412	6,394	6,375	38,529
	b. Debt Component (Line 6 x 1.69% x 1/12)		1,086	1,083	1,080	1,077	1,074	1,071	6,472
8.	Investment Expenses								
	a. Depreciation (E)		2,210	2,210	2,210	2,210	2,210	2,210	13,261
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)		(1,454)	(1,454)	(1,454)	(1,454)	(1,454)	(1,454)	(8,724)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$8,310	$8,289	$8,267	$8,245	$8,224	$8,202	$49,537

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) Depreciation offset for base rate items.

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period July through December 2005

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

Line		Beginning of Period Amount	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$828,789	828,789	828,789	828,789	828,789	828,789	828,789	n/a
3.	Less: Accumulated Depreciation (C)	$69,525	71,735	73,945	76,155	78,365	80,575	82,785	n/a
4.	CWIP - Non Interest Bearing	$0							
5.	Net Investment (Lines 2 - 3 + 4)	$759,264	$757,054	$754,844	$752,634	$750,424	$748,214	$746,004	n/a
6.	Average Net Investment		758,159	755,949	753,739	751,529	749,319	747,109	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		6,357	6,338	6,320	6,301	6,282	6,264	76,390
	b. Debt Component (Line 6 x 1.69% x 1/12)		1,068	1,065	1,062	1,058	1,055	1,052	12,832
8.	Investment Expenses								
	a. Depreciation (E)		2,210	2,210	2,210	2,210	2,210	2,210	26,521
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)		(1,454)	(1,454)	(1,454)	(1,454)	(1,454)	(1,454)	(17,448)
9.	Total System Recoverable Expenses (Lines 7 & 8)		$8,180	$8,159	$8,137	$8,115	$8,094	$8,072	$98,294

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) Depreciation offset for base rate items.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period January through June 2005

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

Line		Beginning of Period Amount	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$250,000	250,000	250,000	250,000	250,000	250,000	250,000	n/a
3.	Less: Accumulated Depreciation (C)	552	1,656	2,760	3,865	4,969	6,073	7,177	n/a
4.	CWIP - Non Interest Bearing								
5.	Net Investment (Lines 2 - 3 + 4)	$249,448	$248,344	$247,240	$246,135	$245,031	$243,927	$242,823	n/a
6.	Average Net Investment		248,896	247,792	246,687	245,583	244,479	243,375	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		2,087	2,078	2,068	2,059	2,050	2,041	12,382
	b. Debt Component (Line 6 x 1.69% x 1/12)		351	349	347	346	344	343	2,080
8.	Investment Expenses								
	a. Depreciation (E)		1,104	1,104	1,104	1,104	1,104	1,104	6,625
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$3,541	$3,531	$3,520	$3,509	$3,498	$3,487	$21,086

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period July through December 2005

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

Line		Beginning of Period Amount	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$0	$0	$1,192,844	$0	$0	$0	$1,192,844
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$250,000	250,000	250,000	1,442,844	1,442,844	1,442,844	1,442,844	n/a
3.	Less: Accumulated Depreciation (C)	$7,177	8,281	9,385	12,279	16,962	21,644	26,327	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$242,823	$241,719	$240,615	$1,430,565	$1,425,882	$1,421,200	$1,416,517	n/a
6.	Average Net Investment		242,271	241,167	835,590	1,428,224	1,423,541	1,418,858	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		2,031	2,022	7,006	11,975	11,935	11,896	59,247
	b. Debt Component (Line 6 x 1.69% x 1/12)		341	340	1,177	2,011	2,005	1,998	9,952
8.	Investment Expenses								
	a. Depreciation (E)		1,104	1,104	2,893	4,683	4,683	4,683	25,775
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$3,477	$3,466	$11,076	$18,669	$18,623	$18,577	$94,974

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period January through June 2005

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

Line		Beginning of Period Amount	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$167,600	$167,400	$167,400	$167,400	$167,400	$667,400	$1,504,600
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$13,997,060	14,164,660	14,332,060	14,499,460	14,666,860	14,834,260	15,501,660	n/a
3.	Less: Accumulated Depreciation (C)	261,218	305,133	349,354	393,883	438,719	483,861	529,977	n/a
4.	CWIP - Non Interest Bearing	0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$13,735,841	$13,859,527	$13,982,705	$14,105,576	$14,228,141	$14,350,399	$14,971,683	n/a
6.	Average Net Investment		13,797,684	13,921,116	14,044,141	14,166,859	14,289,270	14,661,041	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		115,683	116,718	117,749	118,778	119,804	122,921	711,653
	b. Debt Component (Line 6 x 1.69% x 1/12)		19,432	19,606	19,779	19,952	20,124	20,648	119,539
8.	Investment Expenses								
	a. Depreciation (E)		43,915	44,222	44,529	44,835	45,142	46,116	268,759
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$179,029	$180,545	$182,056	$183,565	$185,071	$189,685	$1,099,951

Notes:
(A) Reserve Transfer in February.
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period July through December 2005

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

Line		Beginning of Period Amount	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions								
	b. Clearings to Plant		$167,400	$167,400	$167,400	$167,400	$167,400	$167,400	$2,509,000
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$15,501,660	15,669,060	15,836,460	16,003,860	16,171,260	16,338,660	16,506,060	n/a
3.	Less: Accumulated Depreciation (C)	$529,977	577,066	624,463	672,166	720,176	768,493	817,117	n/a
4.	CWIP - Non Interest Bearing	$0	0	0	0	0	0	0	0
5.	Net Investment (Lines 2 - 3 + 4)	$14,971,683	$15,091,994	$15,211,997	$15,331,694	$15,451,084	$15,570,167	$15,688,943	n/a
6.	Average Net Investment		15,031,838	15,151,995	15,271,846	15,391,389	15,510,625	15,629,555	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		126,030	127,037	128,042	129,045	130,044	131,041	1,482,893
	b. Debt Component (Line 6 x 1.69% x 1/12)		21,170	21,339	21,508	21,676	21,844	22,012	249,088
8.	Investment Expenses								
	a. Depreciation (E)		47,090	47,396	47,703	48,010	48,317	48,624	555,899
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$194,289	$195,773	$197,253	$198,731	$200,206	$201,677	$2,287,880

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period January through June 2005

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

Line		Beginning of Period Amount	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1.	Investments								
	a. Expenditures/Additions		$288,565	$1,593,000	$2,000	$1,568,000	$2,000	$2,000	$3,455,565
	b. Clearings to Plant		$0	$0	$0	$0	$0	$0	$0
	c. Retirements		$0	$0	$0	$0	$0	$0	$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	0	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	0	0	0	0	n/a
4.	CWIP - Non Interest Bearing	11,559,183	11,847,748	13,440,748	13,442,748	15,010,748	15,012,748	15,014,748	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$11,559,183	$11,847,748	$13,440,748	$13,442,748	$15,010,748	$15,012,748	$15,014,748	n/a
6.	Average Net Investment		11,703,465	12,644,248	13,441,748	14,226,748	15,011,748	15,013,748	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		98,124	106,012	112,698	119,280	125,862	125,878	687,855
	b. Debt Component (Line 6 x 1.69% x 1/12)		16,482	17,807	18,930	20,036	21,142	21,144	115,542
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	0	0
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$114,607	$123,819	$131,629	$139,316	$147,003	$147,023	$803,397

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period July through December 2005

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

Line		Beginning of Period Amount	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$4,000	$904,000	$690,500	$1,432,000	$1,080,882	$5,496,432	$13,063,379
	b. Clearings to Plant		$0	$0	$0	$0	$0	$15,454,835	$15,454,835
	c. Retirements		$0	$0	$0	$0	$0	$25,758	$25,758
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	0	0	0	15,454,835	n/a
3.	Less: Accumulated Depreciation (C)	$0	0	0	0	0	0	25,758	n/a
4.	CWIP - Non Interest Bearing	$15,014,748	15,018,748	15,922,748	16,613,248	18,045,248	19,126,130	9,167,727	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$15,014,748	$15,018,748	$15,922,748	$16,613,248	$18,045,248	$19,126,130	$24,622,562	n/a
6.	Average Net Investment		15,016,748	15,470,748	16,267,998	17,329,248	18,585,689	21,874,346	n/a
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		125,904	129,710	136,394	145,292	155,826	183,399	1,564,380
	b. Debt Component (Line 6 x 1.69% x 1/12)		21,149	21,788	22,911	24,405	26,175	30,806	262,776
8.	Investment Expenses								
	a. Depreciation (E)		0	0	0	0	0	25,758	$25,758
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$147,052	$151,498	$159,305	$169,697	$182,001	$239,964	$1,852,914

Notes:

(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period January through June 2005

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

Line		Beginning of Period Amount	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	Six Month Amount
1.	*Investments*								
	a. Expenditures/Additions		$2,383,073	$2,010,000	$832,600	$526,000	$1,322,571	$1,526,000	$8,600,244
	b. Clearings to Plant		$0	$0	$17,688,316	$0	$0	$0	$17,688,316
	c. Retirements								$0
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$0	0	0	17,688,316	17,688,316	17,688,316	17,688,316	n/a
3.	Less: Accumulated Depreciation (C)	0	0	0	47,906	143,718	239,529	335,341	n/a
4.	CWIP - Non Interest Bearing	28,709,826	31,092,899	33,102,899	16,247,183	16,773,183	18,095,754	19,621,754	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$28,709,826	$31,092,899	$33,102,899	$33,887,593	$34,317,782	$35,544,541	$36,974,729	n/a
6.	Average Net Investment		29,901,363	32,097,899	33,495,246	34,102,687	34,931,161	36,259,635	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		250,699	269,115	280,831	285,924	292,870	304,008	1,683,448
	b. Debt Component (Line 6 x 1.69% x 1/12)		42,111	45,205	47,172	48,028	49,195	51,066	282,776
8.	Investment Expenses								
	a. Depreciation (E)				47,906	95,812	95,812	95,812	335,341
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$292,810	$314,320	$375,909	$429,764	$437,877	$450,886	$2,301,566

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period July through December 2005

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

Line		Beginning of Period Amount	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	Twelve Month Amount
1.	Investments								
	a. Expenditures/Additions		$1,948,159	$2,724,286	$2,275,143	$3,936,029	$4,052,462	$4,925,142	$28,461,465
	b. Clearings to Plant		$0	$0	$0	$17,986,457	$0	$250,000	$35,924,773
	c. Retirements								
	d. Other (A)								
2.	Plant-In-Service/Depreciation Base (B)	$17,688,316	17,688,316	17,688,316	17,688,316	35,674,773	35,674,773	35,924,773	n/a
3.	Less: Accumulated Depreciation (C)	$335,341	431,153	526,964	622,776	764,303	951,546	1,139,466	n/a
4.	CWIP - Non Interest Bearing	$19,621,754	21,569,913	24,294,199	26,569,342	12,518,914	16,571,376	21,246,518	n/a
5.	Net Investment (Lines 2 - 3 + 4)	$36,974,729	$38,827,076	$41,455,551	$43,634,882	$47,429,384	$51,294,603	$56,031,825	n/a
6.	Average Net Investment		37,900,903	40,141,314	42,545,216	45,532,133	49,361,993	53,663,214	
7.	Return on Average Net Investment								
	a. Equity Component grossed up for taxes (D)		317,769	336,553	356,708	381,751	413,861	449,924	$3,940,014
	b. Debt Component (Line 6 x 1.69% x 1/12)		53,377	56,532	59,918	64,124	69,518	75,576	$661,822
8.	Investment Expenses								
	a. Depreciation (E)		95,812	95,812	95,812	141,527	187,243	187,920	
	b. Amortization (F)								
	c. Dismantlement								
	d. Property Expenses								
	e. Other (G)								
9.	Total System Recoverable Expenses (Lines 7 & 8)		$466,958	$488,897	$512,438	$587,403	$670,622	$713,419	$5,741,303

Notes:
(A) N/A
(B) Applicable beginning of period and end of period depreciable base by production plant name(s), unit(s), or plant account(s). See Form 42-4P, pages 33-35.
(C) N/A
(D) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(E) Applicable depreciation rate or rates. See Form 42-4P, pages 33-35.
(F) Applicable amortization period(s). See Form 42-4P, pages 33-35.
(G) N/A

Totals may not add due to rounding.

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period January through June 2005

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

Line		Beginning of Period Amount	January Projected	February Projected	March Projected	April Projected	May Projected	June Projected	End of Period Amount	
1	Working Capital Dr (Cr)									
a	158.100 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0		
b	158.200 Allowances Withheld	0	0	0	0	0	0	0		
c	182.300 Other Regulatory Assets-Losses	0	0	0	0	0	0	0		
d	254.900 Other Regulatory Liabilities-Gains	(1,516,143)	(1,497,590)	(1,479,037)	(1,460,483)	(1,441,930)	(2,130,534)	(2,111,981)		
2	Total Working Capital	($1,516,143)	($1,497,590)	($1,479,037)	($1,460,483)	($1,441,930)	($2,130,534)	($2,111,981)		
3	Average Net Working Capital Balance		(1,506,867)	(1,488,313)	(1,469,760)	(1,451,207)	(1,786,232)	(2,121,257)		
4	Return on Average Net Working Capital Balance									
a	Equity Component grossed up for taxes (A)		(12,634)	(12,478)	(12,323)	(12,167)	(14,976)	(17,785)	(82,363)	
b	Debt Component (Line 6 x 1.69% x 1/12)		(2,122)	(2,096)	(2,070)	(2,044)	(2,516)	(2,987)	(13,835)	
5	Total Return Component		($14,756)	($14,574)	($14,393)	($14,211)	($17,492)	($20,773)	($96,198)	(D)
6	Expense Dr (Cr)									
a	411.800 Gains from Dispositions of Allowances		(18,553)	(18,553)	(18,553)	(18,553)	(18,553)	(18,553)	(111,318)	
b	411.900 Losses from Dispositions of Allowances		0	0	0	0	0	0		
c	509.000 Allowance Expense		0	0	0	0	0	0		
7	Net Expense (Lines 6a+6b+6c)		(18,553)	(18,553)	(18,553)	(18,553)	(18,553)	(18,553)	(111,318)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		(33,309)	(33,127)	(32,946)	(32,764)	(36,045)	(39,326)		
a	Recoverable Costs Allocated to Energy		(33,309)	(33,127)	(32,946)	(32,764)	(36,045)	(39,326)		
b	Recoverable Costs Allocated to Demand		0	0	0	0	0	0		
9	Energy Jurisdictional Factor		98.53755%	98.53755%	98.53755%	98.53755%	98.53755%	98.53755%		
10	Demand Jurisdictional Factor		97.87297%	97.87297%	97.87297%	97.87297%	97.87297%	97.87297%		
11	Retail Energy-Related Recoverable Costs (B)		(32,822)	(32,643)	(32,464)	(32,285)	(35,518)	(38,750)	(204,482)	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($32,822)	($32,643)	($32,464)	($32,285)	($35,518)	($38,750)	($204,482)	

Notes:
(A) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule
(E) Line 7 is reported on O&M Schedule

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

Totals may not add due to rounding

Florida Power & Light Company
Environmental Cost Recovery Clause
For the Projected Period July through December 2005

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

Line		Beginning of Period Amount	July Projected	August Projected	September Projected	October Projected	November Projected	December Projected	End of Period Amount	
1	Working Capital Dr (Cr)									
a	158.100 Allowance Inventory	$0	$0	$0	$0	$0	$0	$0		
b	158.200 Allowances Withheld	0	0	0	0	0	0	0		
c	182.300 Other Regulatory Assets-Losses	0	0	0	0	0	0	0		
d	254.900 Other Regulatory Liabilities-Gains	(2,111,981)	(2,093,428)	(2,074,874)	(2,056,321)	(2,037,768)	(2,019,214)	(2,000,661)		
2	Total Working Capital	($2,111,981)	($2,093,428)	($2,074,874)	($2,056,321)	($2,037,768)	($2,019,214)	($2,000,661)		
3	Average Net Working Capital Balance		(2,102,704)	(2,084,151)	(2,065,598)	(2,047,044)	(2,028,491)	(2,009,938)		
4	Return on Average Net Working Capital Balance									
a	Equity Component grossed up for taxes (A)		(17,630)	(17,474)	(17,318)	(17,163)	(17,007)	(16,852)	(185,807)	
b	Debt Component (Line 6 x 1.69% x 1/12)		(2,961)	(2,935)	(2,909)	(2,883)	(2,857)	(2,831)	(31,211)	
5	Total Return Component		($20,591)	($20,409)	($20,227)	($20,046)	($19,864)	($19,682)	($217,018)	(D)
6	Expense Dr (Cr)									
a	411.800 Gains from Dispositions of Allowances		(18,553)	(18,553)	(18,553)	(18,553)	(18,553)	(18,553)	(222,636)	
b	411.900 Losses from Dispositions of Allowances		0	0	0	0	0	0		
c	509.000 Allowance Expense		0	0	0	0	0	0		
7	Net Expense (Lines 6a+6b+6c)		(18,553)	(18,553)	(18,553)	(18,553)	(18,553)	(18,553)	(222,636)	(E)
8	Total System Recoverable Expenses (Lines 5+7)		($39,144)	($38,962)	($38,780)	($38,599)	($38,417)	($38,235)		
a	Recoverable Costs Allocated to Energy		(39,144)	(38,962)	(38,780)	(38,599)	(38,417)	(38,235)		
b	Recoverable Costs Allocated to Demand		0	0	0	0	0	0		
9	Energy Jurisdictional Factor		98.53755%	98.53755%	98.53755%	98.53755%	98.53755%	98.53755%		
10	Demand Jurisdictional Factor		97.87297%	97.87297%	97.87297%	97.87297%	97.87297%	97.87297%		
11	Retail Energy-Related Recoverable Costs (B)		(38,571)	(38,392)	(38,213)	(38,034)	(37,855)	(37,676)	(433,224)	
12	Retail Demand-Related Recoverable Costs (C)		0	0	0	0	0	0	0	
13	Total Jurisdictional Recoverable Costs (Lines11+12)		($38,571)	($38,392)	($38,213)	($38,034)	($37,855)	($37,676)	($433,224)	

Notes:
(A) The Gross-up factor for taxes uses 0.61425, which reflects the Federal Income Tax Rate of 35%; the monthly Equity Component of 6.18% reflects an 11% return on equity.
(B) Line 8a times Line 9
(C) Line 8b times Line 10
(D) Line 5 is reported on Capital Schedule
(E) Line 7 is reported on O&M Schedule

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

Totals may not add due to rounding

Project Number	Plant Name	Plant Account	Depreciation Rate / Amortization Period	Projected January Plant In Service (BOM)	Projected December Plant In Service (EOM)
02 - Low NOX Burner Technology					
	PtEverglades U1	312.0	6.10%	$2,700,574.97	$2,700,574.97
	PtEverglades U2	312.0	6.50%	$2,377,900.75	$2,377,900.75
	Riviera U3	312.0	8.90%	$3,846,591.65	$3,846,591.65
	Riviera U4	312.0	7.90%	$3,272,970.68	$3,272,970.68
	Turkey Pt U1	312.0	8.80%	$2,961,524.84	$2,961,524.84
	Turkey Pt U2	312.0	6.70%	$2,451,904.92	$2,451,904.92
	Total For Project 02			$17,611,467.81	$17,611,467.81
03 - Continuous Emission Monitoring					
	CapeCanaveral Comm	311.0	4.90%	$59,227.10	$59,227.10
	CapeCanaveral Comm	312.0	8.50%	$31,735.95	$31,735.95
	CapeCanaveral U1	312.0	8.80%	$494,606.87	$505,606.87
	CapeCanaveral U2	312.0	8.30%	$511,705.24	$522,705.24
	Cutler Comm	311.0	5.20%	$64,883.87	$64,883.87
	Cutler Comm	312.0	4.50%	$27,351.73	$27,351.73
	Cutler U5	312.0	5.00%	$312,722.43	$323,722.43
	Cutler U6	312.0	5.10%	$314,129.96	$325,129.96
	Manatee Comm	312.0	4.60%	$31,859.00	$31,859.00
	Manatee U1	311.0	2.90%	$56,430.25	$56,430.25
	Manatee U1	312.0	4.00%	$472,570.03	$483,570.03
	Manatee U2	311.0	3.00%	$56,332.75	$56,332.75
	Manatee U2	312.0	4.20%	$508,734.36	$519,734.36
	Martin Comm	312.0	4.60%	$31,631.74	$31,631.74
	Martin U1	311.0	3.30%	$36,810.86	$36,810.86
	Martin U1	312.0	4.80%	$521,075.17	$532,075.17
	Martin U2	311.0	3.30%	$36,845.37	$36,845.37
	Martin U2	312.0	4.90%	$519,484.96	$530,484.96
	PtEverglades Comm	311.0	5.80%	$127,911.34	$127,911.34
	PtEverglades Comm	312.0	7.70%	$61,620.47	$61,620.47
	PtEverglades U1	312.0	6.10%	$453,661.22	$464,661.22
	PtEverglades U2	312.0	6.50%	$475,113.36	$486,113.36
	PtEverglades U3	312.0	7.80%	$503,968.62	$514,968.62
	PtEverglades U4	312.0	8.40%	$512,809.90	$523,809.90
	Riviera Comm	311.0	5.20%	$60,973.18	$60,973.18
	Riviera Comm	312.0	8.90%	$29,117.75	$29,117.75
	Riviera U3	312.0	8.90%	$449,392.38	$460,392.38
	Riviera U4	312.0	7.90%	$433,421.96	$444,421.96
	Sanford U3	311.0	2.40%	$54,282.08	$54,282.08
	Sanford U3	312.0	2.40%	$131,944.80	$131,944.80
	Sanford U3 (Retiring	312.0	0.00%	$315,699.69	$315,699.69
	Scherer U4	312.0	4.50%	$515,653.32	$515,653.32
	SJRPP - Comm	311.0	3.40%	$43,193.33	$43,193.33
	SJRPP - Comm	312.0	3.70%	$66,188.18	$66,188.18
	SJRPP U1	312.0	4.10%	$107,594.02	$107,594.02
	SJRPP U2	312.0	4.20%	$107,562.94	$107,562.94
	Turkey Pt Comm Fsil	311.0	4.30%	$59,056.19	$59,056.19
	Turkey Pt Comm Fsil	312.0	6.90%	$29,110.85	$29,110.85
	Turkey Pt U1	312.0	8.80%	$546,534.15	$557,534.15
	Turkey Pt U2	312.0	6.70%	$505,638.44	$516,638.44
	FtLauderdale Comm	341.0	5.30%	$58,859.79	$58,859.79
	FtLauderdale Comm	345.0	4.20%	$34,502.21	$34,502.21
	FtLauderdale U4	343.0	6.50%	$461,080.14	$483,080.14
	FtLauderdale U5	343.0	6.60%	$471,313.47	$493,313.47
	FtMyers U2 CC	343.0	5.50%	$101,353.39	$101,353.39
	Martin U3	343.0	5.70%	$431,927.00	$453,927.00
	Martin U4	343.0	5.50%	$421,026.31	$443,026.31
	Martin U8	343.0	5.50%	$25,657.00	$25,657.00
	Putnam Comm	341.0	4.20%	$82,857.82	$82,857.82
	Putnam Comm	343.0	5.60%	$3,138.97	$3,138.97
	Putnam U1	343.0	6.00%	$335,440.55	$357,440.55
	Putnam U2	343.0	6.30%	$368,844.07	$390,844.07
	Sanford Comm CC	343.0	11.60%	$5,168.21	$5,168.21
	Sanford U4	343.0	5.50%	$41,859.48	$41,859.48
	Sanford U5	343.0	5.50%	$100,938.52	$100,938.52
	General Plant	391.9	3Yr	$9,927.75	$9,927.75
	Total For Project 03			$12,632,480.49	$12,940,480.49

Project Number	Plant Name	Plant Account	Depreciation Rate / Amortization Period	Projected January Plant In Service (BOM)	Projected December Plant In Service (EOM)
04 - Clean Closure Equivalency Demonstration					
	CapeCanaveral Comm	311.0	4.90%	$17,254.20	$17,254.20
	PtEverglades Comm	311.0	5.80%	$19,812.30	$19,812.30
	Turkey Pt Comm Fsil	311.0	4.30%	$21,799.28	$21,799.28
	Total For Project 04			$58,865.78	$58,865.78
05 - Maintenance of Above Ground Fuel Tanks					
	CapeCanaveral Comm	311.0	4.90%	$901,636.88	$901,636.88
	Manatee Comm	311.0	3.50%	$3,111,263.35	$3,111,263.35
	Manatee Comm	312.0	4.60%	$174,543.23	$174,543.23
	Manatee U1	312.0	4.00%	$104,845.35	$104,845.35
	Manatee U2	312.0	4.20%	$127,429.19	$127,429.19
	Martin Comm	311.0	3.60%	$1,110,450.32	$1,110,450.32
	Martin U1	311.0	3.30%	$176,338.83	$176,338.83
	PtEverglades Comm	311.0	5.80%	$1,132,078.22	$1,132,078.22
	Riviera Comm	311.0	5.20%	$1,042,734.82	$1,042,734.82
	Sanford U3	311.0	2.40%	$796,754.11	$796,754.11
	SJRPP - Comm	311.0	3.40%	$42,091.24	$42,091.24
	SJRPP - Comm	312.0	3.70%	$2,292.39	$2,292.39
	Turkey Pt Comm Fsil	311.0	4.30%	$87,560.23	$87,560.23
	Turkey Pt U2	311.0	5.20%	$42,158.96	$42,158.96
	FtLauderdale Comm	342.0	4.30%	$898,110.65	$898,110.65
	FtLauderdale GTs	342.0	0.70%	$584,290.23	$584,290.23
	FtMyers GTs	342.0	1.20%	$68,893.65	$68,893.65
	PtEverglades GTs	342.0	1.40%	$2,900,625.16	$2,900,625.16
	Putnam Comm	342.0	4.00%	$749,025.94	$749,025.94
	Total For Project 05			$14,053,122.75	$14,053,122.75
07 - Relocate Turbine Lube Oil Piping					
	StLucie U1	323.0	5.90%	$31,030.00	$31,030.00
	Total For Project 07			$31,030.00	$31,030.00
08 - Oil Spill Clean-up/Response Equipment					
	CapeCanaveral Comm	316.7	7Yr	$2,741.16	$2,741.16
	Martin Comm	316.0	4.40%	$23,107.32	$23,107.32
	Martin Comm	316.5	5Yr	$15,228.31	$15,228.31
	Martin Comm	316.7	7Yr	$565,012.49	$565,012.49
	Sanford U3	316.7	7Yr	$6,776.50	$6,776.50
	Turkey Pt Comm Fsil	316.7	7Yr	$7,050.46	$7,050.46
	Turkey Pt U1 (Asset 3933	316.7	7Yr	$1,159.18	$1,159.18
	FtMyers Common	346.7	7Yr	$12,051.85	$12,051.85
	Various Plants Common	346.7	7Yr	$54,948.00	$221,948.00
	Total For Project 08			$688,075.27	$855,075.27
10 - Reroute Storm Water Runoff					
	StLucie Comm	321.0	3.20%	$117,793.83	$117,793.83
	Total For Project 10			$117,793.83	$117,793.83
12 - Scherer Discharge Pipline					
	Scherer Comm	310.0	0.00%	$9,936.72	$9,936.72
	Scherer Comm	311.0	3.60%	$524,872.97	$524,872.97
	Scherer Comm	312.0	5.30%	$328,761.62	$328,761.62
	Scherer Comm	314.0	3.90%	$689.11	$689.11
	Total For Project 12			$864,260.42	$864,260.42
20 - Wastewater/Stormwater Discharge Elimination					
	CapeCanaveral Comm	311.0	4.90%	$856,500.94	$856,500.94
	Martin U1	312.0	4.80%	$225,000.00	$225,000.00
	Martin U2	312.0	4.90%	$0.00	$250,000.00
	PtEverglades Comm	311.0	5.80%	$296,707.34	$296,707.34
	Riviera Comm	311.0	5.20%	$560,786.81	$560,786.81
	Total For Project 20			$1,938,995.09	$2,188,995.09
21 - St. Lucie Turtle Nets					
	StLucie Comm	321.0	3.20%	$828,789.34	$828,789.34
	Total For Project 21			$828,789.34	$828,789.34

Project Number	Plant Name	Plant Account	Depreciation Rate / Amortization Period	Projected January Plant In Service (BOM)	Projected December Plant In Service (EOM)
22 - Pipeline Integrity Management (PIM)					
	Martin Comm	311.0	3.60%	$0.00	$1,192,844.00
	FtLauderdale Comm	341.0	5.30%	$250,000.00	$250,000.00
	Total For Project 22			$250,000.00	$1,442,844.00
23 - Spill Prevention Clean-Up & Countermeasures					
	CapeCanaveral Comm	312.0	8.50%	$812,364.10	$812,364.10
	Cutler Comm	312.0	4.50%	$88,115.33	$88,115.33
	Manatee Comm	312.0	4.60%	$518,002.68	$518,002.68
	Martin Comm	312.0	4.60%	$66,682.03	$66,682.03
	Riviera Common	312.0	8.90%	$153,023.85	$153,023.85
	Riviera U3	312.0	8.90%	$757,398.09	$757,398.09
	Riviera U4	312.0	7.90%	$885,578.22	$885,578.22
	Sanford Common	312.0	3.50%	$764,671.10	$764,671.10
	Turkey Pt Comm Fsil	312.0	6.90%	$30,326.82	$30,326.82
	StLucie U1	324.0	3.20%	$0.00	$500,000.46
	FtLauderdale Comm	342.0	4.30%	$1,252,502.81	$1,252,502.81
	FtLauderdale GTs	342.0	0.70%	$553,266.61	$553,266.61
	FtMyers GTs	342.0	1.20%	$855,065.85	$855,065.85
	PtEverglades GTs	342.0	1.40%	$1,879,867.81	$1,879,867.81
	Putnam Comm	342.0	4.00%	$1,816,787.37	$1,816,787.37
	Transmission	352.0	2.20%	$891,327.74	$1,393,577.74
	Distribution	361.0	2.20%	$2,672,078.39	$4,178,828.39
	Total For Project 23			$13,997,059.80	$16,506,060.26
24 - Manatee Reburn					
	Manatee U1	312.0	4.00%	$0.00	$15,454,835.40
	Total For Project 24			$0.00	$15,454,835.40
25 - PPE ESP Technology					
	PtEverglades U1	312.0	6.10%	$0.00	$17,986,456.89
	PtEverglades U2	312.0	6.50%	$0.00	$17,938,316.18
	Total For Project 25			$0.00	$35,924,773.07
				$63,071,940.58	$118,878,393.51

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 ($25 per ton for both Florida and Georgia) by the tons of each air pollutant emitted by the unit during the previous year and regulated in each unit's air operating permit, up to a total of 4,000 tons per pollutant. The major regulated pollutants at the present time are sulfur dioxide (SO_2), nitrogen oxides (NO_x) and particulate matter. The fee covers units in FPL's service area, as well as Unit 4 of Plant Scherer located in Juliette, Georgia, within the Georgia Power Company service area. Scherer Unit 4's annual air operating permit fee is approximately $ 96,000. 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, 2004 to December 31, 2004)
The monthly fees for 2003 emissions at Scherer have been paid and continue to be paid in 2004. 2003 air operating permit fees for the Florida facilities were calculated in January 2004 utilizing 2003 operating information. They were paid to the FDEP in March 2004.

Project Fiscal Expenditures:
(January 1, 2004 to December 31, 2004)
Project expenditures are estimated to be $189,254 or 9.2% lower than previously projected. The process for estimating air permit fees has been refined in order to produce more accurate estimates.

Project Progress Summary:
The monthly fees for 2003 emissions at Scherer have been paid and continue to be paid in 2004. 2003 air operating permit fees for the Florida facilities were calculated in January 2004 utilizing 2003 operating information. They were paid to the FDEP in March 2004.

Project Projections:
Estimated project expenditures for the period January 2005 through December 2005 are expected to be $1,908,804.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Continuous Emission Monitoring Systems - 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 SO_2, NO_x and carbon dioxide (CO_2) emissions, as well as volumetric flow and opacity data from affected air pollution sources. FPL has 33 units which are affected and which have installed CEMS to comply with these requirements.

40 CFR Part 75 includes the general requirements for the installation, certification, operation and maintenance of CEMS and specific requirements for the monitoring of pollutants, opacity and volumetric flow. Periodically, these systems 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 will be an ongoing activity following their installation.

Project Accomplishments:
(January 1, 2004 to December 31, 2004)
Relative Accuracy Tests and Linearity Tests continue to be performed as scheduled. Maintenance has been performed on the analyzers. Calibration gases and CEMS parts have been purchased. Analysis of the fuel oil for sulfur content continues to be performed.

Project Fiscal Expenditures:
(January 1, 2004 to December 31, 2004)
Project expenditures are estimated to be $79,952 or 12.6% higher than previously projected primarily due to higher than originally projected payments to the software vendor for technical support.

Project Progress Summary:
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:
Estimated project expenditures for the period January 2005 through December 2005 are expected to be $711,876.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Clean Closure Equivalency - O&M
Project No. 4a
Project Description:
In compliance with 40 CFR 270.1(c)(5) and (6), FPL developed CCED's 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:
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2004 to December 31, 2004)
None

Project Progress Summary:
Complete

Project Projections:
None

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.

The required base line internal inspections have been completed and the future internal inspections have been scheduled based on the established corrosion rate of the tank bottoms. Future costs will be incurred for required 5 year external inspections and repairs.

Project Accomplishments:
(January 1, 2004 to December 31, 2004)
Work continued on miscellaneous maintenance of above ground fuel storage tanks and piping systems. All required API 653 external inspections have been completed for this year and all 2004 tank registration fees have been paid. Also, 4 tanks required painting and are in progress to and will be finished by the end of the year.

Project Fiscal Expenditures:
(January 1, 2004 to December 31, 2004)
Project expenditures are estimated to be $485,412 or 105.4% higher than previously projected. This project includes performing required repairs identified during tank inspections. The variance is primarily due to an updated estimate of the costs associated with the required repairs and painting, based on the results of tank inspections.

Project Progress Summary:
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.

Project Projections:
Estimated project fiscal expenditures for the period January 2005 through December 2005 are expected to be $448,000.

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, 2004 to December 31, 2004)
Plan updates have continued to be performed and filed for all sites as required. Routine maintenance of all oil spill equipment has continued throughout the year as well as the performance of spill management drills including a corporate team drill and deployment drills throughout the system. There has also been training for some team members.

Project Fiscal Expenditures:
(January 1, 2004 to December 31, 2004)
Project expenditures are estimated to be $41 or 0.0% higher than previously projected.

Project Progress Summary:
This is an ongoing project. Each reporting period will include ongoing maintenance of all oil spill equipment in accordance with OPA 90.

Project Projections:
Estimated project fiscal expenditures for the period January 2005 through December 2005 are expected to be $165,996.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Low-Level Radioactive Waste Access Fees - O & M
Project No. 9
Project Description:
Florida Power & Light Company is required to pay Low-Level Waste Access fees for the development of a second regional disposal facility in order to be able to dispose of its low-level radioactive waste at the Barnwell, South Carolina, Low-Level Waste Disposal Site. No other disposal sites are available to FPL for disposal of low-level radioactive waste.

The Low-Level Waste Access fees are invoiced and paid quarterly. The fees are calculated and assessed according to a fixed formula that is applied to all Southeast Compact low-level waste generators. The amount of the fee depends upon the volume of the low-level waste that FPL disposes of at the Barnwell Low-Level Waste Disposal Facility vs. the volume of low-level waste disposes of at Barnwell by all Southeast Compact generators.

Project Accomplishments:
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2004 to December 31, 2004)
None

Project Progress Summary:
Complete

Project Projections:
None

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 (RFA's) 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 (SWMU's). FPL may also conduct assessments of human health risk 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, 2004 to December 31, 2004)
EPA and the FDEP have agreed that no further action is required at the Fort Myers and Martin Power Plants. EPA and the FDEP agree that no further action is required at the Putnam Power Plant, except for the petroleum clean-up that is going forward under the FDEP District Office waste clean-up oversite. EPA issued a RCRA Section 3007 order for site wide corrective action activities at the Manatee, Sanford, Turkey Point and St. Lucie Power Plants. Currently the EPA and FDEP have set no dates for the site visits. FPL is involved in ongoing discussions with the EPA and FDEP regarding the 3007 Order.

Project Fiscal Expenditures:
(January 1, 2004 to December 31, 2004)
Project expenditures are estimated to be $50,002 or 100.0% higher than previously projected. This variance is primarily due an increase in projected costs associated with the preparation of the Manatee and Sanford facilities for an assessment by the EPA. These expenditures are contingent upon receiving notification from EPA of the intent to move forward with the process and were not included in the original projections.

Project Progress Summary:
This is an ongoing project. The next Visual Site Inspection date is pending. No further action is required at Ft. Myers, Martin Power Plants and Putnam except for some petroleum clean up at Putnam.

Project Projection:
Estimated project expenditures for the period of January 2005 through December 2005 are expected to be $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, Florida Power & Light Company (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. After the first year, annual fees are due and payable to the FDEP by January 15th of each year.

Project Accomplishments:
(January 1, 2004 to December 31, 2004)
The NPDES permit fees were paid to the FDEP during the month of January for Power Generation facilities.

Project Fiscal Expenditures:
(January 1, 2004 to December 31, 2004)
Project expenditures are estimated to be $8,602 or 6.4% higher than previously projected.

Project Progress Summary:
The NPDES permit fees were paid to the FDEP during the month of January for Power Generation facilities.

Project Projections:
Estimated project expenditures for the period January 2005 through December 2005 are expected to be $156,400.

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, 2004 to December 31, 2004)
Ash de-watering has been completed at Riviera. Currently processing material at Manatee, which will be completed in August 2004. Ash de-watering is planned for the rest of 2004 at Martin, Turkey Point, and Cape Canaveral.

Project Fiscal Expenditures:
(January 1, 2004 to December 31, 2004)
Project expenditures are estimated to be $2,367 or 0.8% lower than previously projected.

Project Progress Summary:
This is an ongoing project. The frequency of basin clean out is a function of basin capacity and rate of sludge/ash generation. Typically, FPL generates 5,000 tons (@ 50% solids) of sludge per year.

Project Projections:
Estimated project fiscal expenditures for the period January 2005 through December 2005 are expected to be $269,001.

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. Additionally, the majority of activities will be conducted in Dade and Broward counties which adhere to county regulations as defined in municipal codes. This project includes the prevention and removal of pollutant discharges at FPL substations and will prevent further environmental degradation.

Project Accomplishments:
(January 1, 2004 to December 31, 2004)
Plan development started in 1997 and fieldwork is planned to continue through 2005. The majority of the completed work has been in Dade, Broward and Palm Beach counties. Regasketing and encapsulation work continues in the North Area and the West Areas with progress in Palm Beach County. The majority of remediation work has been performed in Miami-Dade County.

A total of 709 transformer locations have been remediated since 1997. A total of 407 transformers have been regasketed and 834 transformers have been encapsulated. Additionally 444 transmission breakers have been encapsulated.

Project Fiscal Expenditures:
(January 1, 2004 to December 31, 2004)
Project expenditures are estimated to be:
- **19a Project expenditures are estimated to be $34,386 or 3.0% higher than projected. The project was** accelerated in the first half of the year to take advantage of good weather. Equipment clearances were obtained which would not be available during the storm season.
- 19b Project expenditures are estimated to be $21,012 or 2.8% higher than projected. The project was accelerated in the first half of the year to take advantage of good weather. Equipment clearances were obtained which would not be available during the storm season.
- 19c No variance is anticipated.

Project Progress Summary:
Miami-Dade County DERM determined that remediation and ground water monitoring were required by FPL to resolve issues at distribution substations where arsenic has been found in ground water. The regasketing and encapsulation phase of the project continues.

Project Projections:
Estimated project fiscal expenditures for the period January 2005 through December 2005 are expected to be $1,513,168.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Wastewater/Stormwater Discharge Elimination & Reuse - O&M
Project 20a
Project Description:
Pursuant to 33 U.S.C. Section 1342 and 40 CFR 122, FPL is required to obtain NPDES permits for each power plant facility. The last permits issued contain requirements to develop and implement a Best Management Practice Pollution Prevention Plan (BMP3 Plan) to minimize or eliminate, whenever feasible, the discharge of regulated pollutants, including fuel oil and ash, to surface waters. In addition, the 1997 Federal Ambient Water Quality Criteria requires FPL to meet surface water standards for any wastewater discharges to groundwater at all plants and the Dade County DERM requires Turkey Point and Cutler Plant wastewater discharges into canals to meet county water quality standards found in Section 24-11, Code of Metropolitan Dade County.

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

Project Accomplishments:
(January 1, 2004 to December 31, 2004)
On hold until further analysis can be obtained.

Project Fiscal Expenditures:
(January 1, 2004 to December 31, 2004)
Project expenditures are estimated to be $40,000 or 80.0% lower than projected. The installation of the Electrostatic Precipitators (ESPs) at the Port Everglades Plant may result in less ash sluice water going to treatment basins, thereby reducing the amount of treated ash sluice water available for reuse. Once the ESP is operational, analyses will be performed to determine the amount of sluice water available for reuse at the plant. This project will be deferred until information resulting from the analyses is obtained.

Project Progress Summary:
On hold until further analysis can be obtained.

Project Projections:
Estimated project fiscal expenditures for the period January 2005 through December 2005 are expected to be $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 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, 2004 to December 31, 2004)
The baseline assessments were undertaken for the Martin 18" and 30" pipelines and associated evaluation is underway.

Project Fiscal Expenditures:
(January 1, 2004 to December 31, 2004)
Project expenditures are estimated to be $180,225 or 450.5% higher than projected. A failure and oil spill at the Martin 30" pipeline required a response and repair. In order to ensure the integrity of the pipeline following repair, a complete analysis of the pipeline was required. This analysis was originally projected for 2005 but was accelerated.

Project Progress Summary:
This is an ongoing project. The baseline assessments are 60% complete at this time and the final evaluations are pending. These assessments are expected to be complete by the end of 2004.

Project Projections:
Estimated project fiscal expenditures for the period January 2005 through December 2005 are expected to be $175,000.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: SPCC (spill prevention, control, and countermeasures) – O&M
Project No.23a
Project Description:
The EPA first established the SPCC Program in 1973 when the agency issued the Oil Pollution Prevention Regulation (i.e., SPCC rule) to address the oil spill prevention provisions contained in the Federal Water Pollution Control Act of 1972 (later amended as the Clean Water Act). The purpose of the regulation was to prevent discharges of oil from reaching the navigable waters of the U.S. or adjoining shorelines and to prepare facility personnel to respond to oil spills. The SPCC regulation requires certain facilities to prepare and implement SPCC Plans and address oil spill prevention requirements including the establishment of procedures, methods, equipment, and other requirements to prevent discharges of oil as described above. Specifically, the rule applies to any owner or operator of a non-transportation related facility that:

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

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

In January 1988, a large storage tank owned by Ashland Oil Company at a site in western Pennsylvania collapsed, releasing approximately 750,000 gallons of diesel fuel to the Monongahela River. Following calls for new tank legislation, an EPA task force recommended expanded regulation of aboveground tanks within the framework of existing legislative authority. The result was EPA's SPCC rulemaking package, the first phase of which was proposed in 1991. Due to a series of agency delays primarily resulting from the 1989 Exxon Valdez oil spill that required EPA to issue the Facility Response Plan rule under the Oil Pollution Act of 1990, the final SPCC Rule was not published until July of 2002.

Project Accomplishments:
(January 1, 2004 to December 31, 2004)
The drawings required to support the SPCC plan updates for all the plants and fuel terminals should be completed in the third quarter. The updated SPCC plans are scheduled to be completed by the end of the year, ready for internal reviews. A majority of the internal reviews are also scheduled to be completed by the end of the year. It is anticipated that the project will have all the required upgrades identified by the end of the year.

Project Fiscal Expenditures:
(January 1, 2004 to December 31, 2004)
Project expenditures are estimated to be $64,571 or 25.8% lower than projected. The EPA has extended the deadlines for SPCC compliance. SPCC Plans will now be due in August 2005 and the facility upgrades will be due in February 2006. Costs associated with the development of SPCC plans, which were included in the original projections, have shifted to 2005.

Project Progress Summary:
By the end of 2004, we plan to have all required drawings updated, and the updated SPCC plans complete and ready for internal review. A majority of the internal reviews should also be complete, as well as the identification of required plant upgrades. It should be noted that the EPA has changed the due date for updating the SPCC plans from August 2004 to August 2005.

Project Projections:
Estimated project expenditures for the period January 2005 through December 2005 are expected to be $124,808.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Manatee Reburn – O&M
Project No.24a
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, 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, 2004 to December 31, 2004)
The Manatee Reburn project for O&M is in its early stages and FPL has put together cost estimates, looked at alternatives for NOx control technology, and worked with the Florida Department of Environmental Protection to reach an agreement to ensure compliance with ozone ambient air quality standards in the Tampa Bay Airshed.

Project Fiscal Expenditures:
(January 1, 2004 to December 31, 2004)
None

Project Progress Summary:
None for the O&M portion of the Manatee Reburn Project.

Project Projections:
Estimated project expenditures for the period January 2005 through December 2005 are expected to be $0.

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's Category-A is single-walled tanks or underground single-walled piping with no secondary containment that was installed before June 30, 1992.

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

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

FPL has six Category-A and two Category-B Storage Tank Systems that must be removed or replaced in order to meet the performance standards of Rule 61-761.500. In 2004 FPL will replace the two single-walled USTs located at the Turkey Point Nuclear Plant Units 1 and 2 with ASTs providing secondary containment (concrete walls and floor) surrounding the tanks. Also in 2004, FPL will remove one single-walled UST located at the Ft. Lauderdale Plant and will not replace the tank. In 2005-2006 FPL will replace the single-walled USTs located at the Area Office Broward (one UST in 2005), Customer Service East Office (one UST in 2006), Juno Beach Office (one UST in 2005), and General Office (2 USTs in 2005), with double-walled tanks providing electronic leak detection. Additionally, the AST to be installed at the Area Broward Office will be concrete vaulted.

The removal and replacement of the USTs will be performed by outside contractors. Additionally, closure assessments will be performed in accordance with 62-761.800 and closure assessment reports will be submitted to local Counties, and the Department of Environmental Services (DEP).

Project Accomplishments:
(January 1, 2004 to December 31, 2004)
Initial review of the scope of work has been completed. The Nuclear Division's portion of the project is expected to begin in July and be completed in September 2004.

Project Fiscal Expenditures:
(January 1, 2004 to December 31, 2004)
No variance is expected.

Project Progress Summary:
Initial review of the scope of work has been completed.

Project Projections:
Estimated project expenditures for the period January 2005 through December 2005 are expected to be $568,000.

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." As I explain below, 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 and Cape Canaveral Plants. 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 and Cape Canaveral Plants in their current CUPs. For the Sanford facility, Condition 15 of CUP No. 9202, issued in June 2000, requires the lowest quality of water to be used that is feasible to meet the needs of the facility. The requirement for the Cape Canaveral Plant is found in Conditions 14 and 15 of CUP No. 10652, issued October 2001, which address the quantity of reclaimed water to be used and require that all available reclaimed water be used prior to groundwater.

Project Accomplishments:
(January 1, 2004 to December 31, 2004)
The project at Sanford is currently operational. Waiting on final approval from DEP for our discharge permit at Cape Canaveral Plant.

Project Fiscal Expenditures:
(January 1, 2004 to December 31, 2004)
The variance of $68,370 or 18.5% lower than higher than projected. This variance is primarily due to a delay in the permitting for the Reclaimed Water Use at the Cape Canaveral Plant. The plant was not able to use the lowest quality water source during the first and second quarters of 2004 which resulted in lower than projected expenditures.

Project Progress Summary:
(January 2004 - December 2004)
The project at Sanford is currently operational. Waiting on final approval from DEP for our discharge permit at Cape Canaveral Plant.

Project Projections:
Estimated project fiscal expenditures for the period January 2005 through December 2005 are expected to be $378,000.

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. It constitutes Phase II in the United States Environmental Protection Agency's (EPA) development of section 316 (b) regulations and establishes national requirements applicable to, and that reflect the best technology available (BTA) for, the location, design, construction and capacity of existing cooling water intake structures (CWIS) to minimize adverse environmental impact. It is anticipated that this Phase II Rule will potentially impact the following FPL facilities: Cape Canaveral, Cutler, Fort Myers, Ft. Lauderdale, Port Everglades, Riviera, Sanford (Unit 3 only) and St. Lucie Power Plants.

Project Accomplishments:
This project is in the early stages and information gathering should start by September 2004.

Project Fiscal Expenditures:
Nothing has been spent so far but we expect to spend $500,000 by year-end.

Project Progress Summary:
This project is in the early stages and information gathering should start by September 2004. Vendors are being selected in August 2004.

Project Projections:
Estimated project fiscal expenditures for the period January 2005 through December 2005 are expected to be $2,327,196.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Low NOx Burner Technology - Capital
Project No. 2
Project Description:
Under Title I of the Clean Air Act Amendments of 1990, Public Law 101-349, utilities with units located in areas designated as "non-attainment" for ozone will be required to reduce NO_x emissions. The Dade, Broward and Palm Beach county areas were classified as "moderate non-attainment" by the EPA. FPL has six units in this affected area.

LNBT meets the requirement to reduce NO_x emissions by delaying the mixing of the fuel and air at the burner, creating a staged combustion process along the length of the flame. NO_x formation is reduced because peak flame temperatures and availability of oxygen for combustion is reduced in the initial stages.

Project Accomplishments:
(January 1, 2004 to December 31, 2004)
All six units are in service and operational.

Project Fiscal Expenditures:
(January 1, 2004 to December 31, 2004)
The variance in depreciation and return is estimated to be $10,495 or 0.5% lower than projected.

Project Progress Summary:
Dade, Broward and Palm Beach Counties have now been redesignated as "attainment" for ozone with air quality maintenance plans. This redesignation 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:
Estimated project fiscal expenditures (depreciation and return) for the period January 2005 through December 2005 are expected to be $1,911,206.

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 SO_2, NO_x and carbon dioxide (CO_2) emissions, as well as volumetric flow, heat input, and opacity data from affected air pollution sources. FPL has 36 units which are affected and which have installed CEMS to comply with these requirements.

40 CFR Part 75 includes the general requirements for the installation, certification, operation and maintenance of CEMS and specific requirements for the monitoring of pollutants, opacity, heat input, and volumetric flow. These regulations are very comprehensive and specific as to the requirements for CEMS, and in essence, they define the components needed and their configuration. Periodically, these systems extract and analyze gaseous samples for each power plant stack and have automated data acquisition and reporting capability.

Project Accomplishments:
(January 1, 2004 to December 31, 2004)
NOx Continuos Emission Monitoring analyzers were installed at all fossil facilities.

Project Fiscal Expenditures:
(January 1, 2004 to December 31, 2004)
The variance in depreciation and return is $46,634, or 3.2% lower than projected. $126,336 of CEMS equipment retirements at various plants were not included in the original projections. Additionally, $473,948 of 7-year amortizable CEMS equipment retirements are estimated for August 2004 which were not included in the original projections.

Project Progress Summary:
The project is complete. All upgrades were done by April 2004.

Project Projections:
Estimated project fiscal expenditures (depreciation and return) for the period January 2005 through December 2005 are expected to be $1,522,752.

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 CCED's 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, 2003 to December 31, 2003)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2003 to December 31, 2003)
The variance in depreciation and return is estimated to be $22 or 0.4% lower than projected.

Project Progress Summary:
Complete

Project Projections:
Estimated project fiscal expenditures (depreciation and return) for the period January 2005 through December 2005 are expected to be $6,154.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Maintenance of Stationary Above Ground Fuel Storage Tanks – Capital
Project No.5b
Project Description:
Florida Administrative Code (F.A.C.) Chapter 17-762, which became effective on March 12, 1991, provides standards for the maintenance of stationary above ground fuel storage tank systems. These standards impose various implementation schedules for inspections/repairs and upgrades to fuel storage tanks.

The capital project associated with complying with the new standards includes the installation of items for each tank such as liners, cathodic projection systems and tank high-level alarms.

Project Accomplishments:
(January 1, 2003 to December 31, 2003)
The double bottom has been installed in tank 901 at Port Everglade's plant and this job is final. The installation of the double bottom in 902 at Port Everglade's plant is complete. The Riviera Plant B tank internal API 653 inspection has been completed and the tank returned to service.

Project Fiscal Expenditures:
(January 1, 2004 to December 31, 2004)
The variance in depreciation and return of $98,519, or 6.1% lower than projected is primarily due to actual retirements of $531,139 for the Port Everglades GT units. These retirements were not included in the original projections.

Project Progress Summary:
FPL has completed initial inspections and upgrades for all of its tanks. Two of the storage tanks located at the Port Everglades Terminal needed to be retrofitted with new double bottoms because the initial FDEP approved method for double bottom leak detection system used by FPL has failed over the past two years. These are complete. FPL has obtained alternate procedures from the Florida Department of Environmental Protection to install these double bottom leak detection systems along with additional alarms and valve containment systems for the light oil tanks in lieu of secondary containment dike liners. The alternate procedures may be rescinded by FDEP in the next couple of years. Additionally, the Riviera plant B tank was due for an internal API 653 inspection in 2004. This inspection and associated repairs have been completed.

Project Projections:
Estimated project fiscal expenditures (depreciation and return) for the period January 2005 through December 2005 are expected to be $1,887,050.

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, 2004 to December 31, 2004)
All activities are complete.

Project Fiscal Expenditures:
The variance in depreciation and return is estimated to be $14 or 0.4% lower than projected.

Project Progress Summary:
This project is complete.

Project Projections:
Estimated project fiscal expenditures (depreciation and return) for the period January 2005 through December 2005 are expected to be $3,306.

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, 2004 to December 31, 2004)
All equipment is being maintained and replaced according to capital budgeting requirements in order to maintain compliance with regulatory guidelines for response readiness.

Project Fiscal Expenditures:
(January 1, 2004 to December 31, 2004)
The variance in depreciation and return of $26,484 or 18.7% lower than projected is primarily due to $86,208 of 7-year amortizable retirements at Martin common, which are now estimated to occur in August 2004. These retirements were not included in the original projections.

Project Progress Summary:
All deadlines, both state and federal, have been met. Ongoing costs will be annual in nature and will consist of equipment upgrades/replacements.

Project Projections:
Estimated project fiscal expenditures (depreciation and return) for the period January 2005 through December 2005 are expected to be $133,083.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Relocate Storm Water Runoff – Capital
Project No.10
Project Description:
The new National Pollutant Discharge Elimination System (NPDES) permit, Permit No. FL0002206, for the St. Lucie Plant, issued by the United States Environmental Protection Agency contains new effluent discharge limitations for industrial-related storm water from the paint and land utilization building areas. The new requirements become effective on January 1, 1994. As a result of these new requirements, the effected areas will be surveyed, graded, excavated and paved as necessary to clean and redirect the storm water runoff. The storm water runoff will be collected and discharged to existing water catch basins on site.

Project Accomplishments:
(January 1, 2004 to December 31, 2004)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2004 to December 31, 2004)
The variance in depreciation and return is estimated to be $29 or 0.3% lower than projected.

Project Progress Summary:
Complete

Project Projections:
Estimated project fiscal expenditures (depreciation and return) for the period January 2005 through December 2005 are expected to be $12,852.

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 Quality control Act, as amended, the Federal Clean Water Act, as amended, and the rules and regulations promulgated thereunder, 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 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, 2004 to December 31, 2004)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2004 to December 31, 2004)
The variance in depreciation and return is estimated to be $284 or 0.3% lower than projected.

Project Progress Summary:
Complete

Project Projections:
Estimated project fiscal expenditures (depreciation and return) for the period January 2005 through December 2005 are expected to be $94,522.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Disposal of Non-Contaminated Liquid Waste – Capital
Project No.17b
Project Description:
FPL manages ash from heavy oil fired power plants using a wet ash system. Ash from the dust collector and economizer is sluiced to surface ash basins. The ash sludge is then pH adjusted to precipitate metals. In order to comply with Florida Administrative Code 62-701.300 (10), the ash is then de-watered using a plate/frame filter-press in order to dispose of it in a Class I landfill or ship by railcar to a processing facility for beneficial reuse.

Project Accomplishments:
(January 1, 2004 to December 31, 2004)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2004 to December 31, 2004)
The variance of $3,025 or 11.0% lower than projected is primarily due to $311,009 of 7-year amortizable retirements of general plant equipment which are now estimated to occur in August 2004. These retirements were not included in the original projections.

Project Progress Summary:
Complete

Project Projections:
Estimated project fiscal expenditures (depreciation and return) for the period January 2005 through December 2005 are expected to be $0.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Wastewater Discharge Elimination & Reuse – Capital
Project No.20
Project Description:
Pursuant to 33 U.S.C. Section 1342 and 40 CFR 122, FPL is required to obtain NPDES permits for each power plant facility. The last permits issued contain requirements to develop and implement a Best Management Practice Pollution Prevention Plan (BMP3 Plan) to minimize or eliminate, whenever feasible, the discharge of regulated pollutants, including fuel oil and ash, to surface waters. In addition, the 1997 Federal Ambient Water Quality Criteria requires FPL to meet surface water standards for any wastewater discharges to groundwater at all plants and the Dade County DERM requires Turkey Point and Cutler Plant wastewater discharges into canals to meet county water quality standards found in Section 24-11, Code of Metropolitan Dade County.

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

Project Accomplishments:
(January 1, 2004 to December 31, 2004)
All activities are complete.

Project Fiscal Expenditures:
(January 1, 2004 to December 31, 2004)
The variance in depreciation and return is $79,207 or 28.7% lower than projected. This variance is primarily due to timing differences. Wastewater reuse system installations at the Martin and Cape Canaveral Plants, which were originally projected to go in-service in January 2004, are now projected for December 2004.

Project Progress Summary:
Complete

Project Projections:
Estimated project fiscal expenditures (depreciation and return) for the period January 2005 through December 2005 are expected to be $276,883.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Turtle Net at St Lucie Nuclear Plant – Capital
Project No.21
Project Description:
The Turtle Net project says that FPL is limited in the number of lethal turtle takings permitted at its St. Lucie Power Plant by the Incidental Take Statement contained in the Endangered Species Act Section 7 Consultation Biological Opinion, issued to FPL on May 4, 2001 by the National Marine Fisheries Service ("NMFS"). The number of lethal takings permitted in a given year is calculated by taking one percent of the total number of loggerhead and green turtles captured in that year. (The Incidental Take Statement separately limits the number of lethal takings of Kemp's Ridley turtles to two per year over the next ten years, and the number of lethal takings of either hawksbill or leatherback turtles to one of those species every two years over the next ten years). Based on the number of captured turtles in 2001, the lethal take limit for loggerhead and green turtles in that year was six (references; Nuclear Regulatory Commission letter dated May 18, 2001 included as Exhibit 1, Document No. 1, Endangered Species Act Section 7 Consultation Biological Opinion Incidental Take Statement dated May 4, 2001 included as Exhibit 1, Document No. 2, Appendix B To Facility Operating License No. NPF-16 St. Lucie Unit 2, Environmental Protection Plan, Non-Radiological, Amendment No. 103 included as Exhibit 1, Document No. 3). In 2001, FPL experienced six lethal takings of loggerhead and green turtles at the St. Lucie Power Plant, indicating that its existing measures to limit such takings were performing marginally.

Project Accomplishments:
(January 1, 2004 to December 31, 2004)
The Turtle Net Project has been fully completed in November 2002.

Project Fiscal Expenditures:
(January 1, 2004 – December 31, 2004)
The variance in depreciation and return is $207 or 0.2% lower than projected.

Project Progress Summary:
Complete

Project Projections:
Estimated project fiscal expenditures (depreciation and return) for the period January 2005 through December 2005 are expected to be $98,294 of capital.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Pipeline Integrity Management (PIM) – Capital
Project No.22
Project Description:
FPL is required to develop a written pipeline integrity management program for its hazardous liquid pipelines. This program must include the following elements: (1) a process for identifying which pipeline segments could affect a high consequence area; (2) a baseline assessment plan; (3) an information analysis that integrates all available information about the integrity of the entire pipeline and the consequences of a failure; (4) the criteria for determining remedial actions to address integrity issues raised by the assessments and information analysis; (5) a continual process of assessment and evaluation of pipeline integrity; (6) the identification of preventive and mitigative measures to protect the high consequence area; (7) the methods to measure the program's effectiveness; (8) a process for review of assessment results and information analysis by a person qualified to evaluate the results and information; and, (9) record keeping.

Project Accomplishments:
(January 1, 2004 to December 31, 2004)
This project is in the conceptual design phase and the design should be complete by year-end. Once this is done it will be put out to bid.

Project Fiscal Expenditures:
(January 1, 2004 to December 31, 2004)
The variance in depreciation and return is $99,690 or 98.5% lower than projected. This variance is primarily due to the deferral of most of the work planned for 2004 to 2005. The hydraulic study and meter testing for the Martin 30" pipeline was completed and results determined that the installation of positive displacement meters was required. These meters needed to be special ordered. Additionally, the study and testing determined that some of the pipeline system needs to be modified with new valves and piping to accommodate the meter system as well as some instrumentation. The meters are a long lead time item and due to the lead time and requirements for having to take the 30" pipeline out of service to perform the work it was determined that this work needed to be moved to 2005.

Project Progress Summary:
This is an ongoing project. Step two is the baseline assessment plan and it is well on the way. Step three is next which is information analysis will also include the installation of some equipment on FPL's 30" Martin pipeline and this should begin in January 2005.

Project Projections:
Estimated project fiscal expenditures (depreciation and return) for the period January 2005 through December 2005 are expected to be $94,974.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: SPCC (spill prevention, control, and countermeasures) – Capital
Project No.23b
Project Description:
The EPA first established the SPCC Program in 1973 when the agency issued the Oil Pollution Prevention Regulation (i.e., SPCC rule) to address the oil spill prevention provisions contained in the Federal Water Pollution Control Act of 1972 (later amended as the Clean Water Act). The purpose of the regulation was to prevent discharges of oil from reaching the navigable waters of the U.S. or adjoining shorelines and to prepare facility personnel to respond to oil spills. The SPCC regulation requires certain facilities to prepare and implement SPCC Plans and address oil spill prevention requirements including the establishment of procedures, methods, equipment, and other requirements to prevent discharges of oil as described above. Specifically, the rule applies to any owner or operator of a non-transportation related facility that:

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

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

In January 1988, a large storage tank owned by Ashland Oil Company at a site in western Pennsylvania collapsed, releasing approximately 750,000 gallons of diesel fuel to the Monongahela River. Following calls for new tank legislation, an EPA task force recommended expanded regulation of aboveground tanks within the framework of existing legislative authority. The result was EPA's SPCC rulemaking package, the first phase of which was proposed in 1991. Due to a series of agency delays primarily resulting from the 1989 Exxon Valdez oil spill that required EPA to issue the Facility Response Plan rule under the Oil Pollution Act of 1990, the final SPCC Rule was not published until July of 2002.

Project Accomplishments:
(January 1, 2004 to December 31, 2004)
The major projects which will be completed by the Power Generation Division in 2004 are:
Riviera Plant – Double walling of fuel oil piping
Lauderdale Plant – Secondary containment liner on tanks 2, 3 & 5 and double wall fuel oil piping
Putnam Plant – Secondary containment liner tanks C-G and double walling of fuel oil piping
Ft Myers Plant – Secondary containment liner tanks 1 & 2
Lauderdale Plant – Secondary containment liner tanks 901 & 902 & Double wall fuel oil piping

Project Fiscal Expenditures:
(January 1, 2004 to December 31, 2004)
The variance in depreciation and return is $376,102 or 28.0% lower than projected. This variance is primarily due to the timing of additions, which resulted in the average plant balance being lower than originally projected. Projects that were originally anticipated to go in-service during the prior reporting period will now be placed in service this reporting period. The reduction in the average plant balance due to timing differences was partially offset by the additional of activities (double-wall fuel oil piping at Riviera Plant Units 3 and 4, Sanford Plant Unit 3, and Cape Canaveral Plant, and fuel oil piping sheet pile diversion at Manatee Plant) which were not included in the original projections.

Project Progress Summary:
The Power Generation Division is on schedule for completing all the required modifications at the power plant sites in order to comply with revised spill prevention control & countermeasure rule.

Project Projections:
Estimated project expenditures (depreciation and return) for Power Systems and Power Generation, for the period January 2005 through December 2005 are expected to be $2,287,880.

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, 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, 2004 to December 31, 2004)
Bid evaluation of potential Reburn Contractors is complete and a preferred contractor has been selected, pending the results of final negotiations, we are expecting a signed contract by the end of September 2003. If a contract is consummated in September, we would expect process and detail design to be approximately 30% complete by year end. We have expended approximately $110,000.00 in contracted in-house Reburn related modeling studies.

Project Fiscal Expenditures:
(January 1, 2004 to December 31, 2004)
The variance in depreciation and return is estimated to be $299,991 or 97.8% higher than projected. This variance is due to timing differences - a larger portion of the expenditures being made in the earlier months of 2004 which were projected to be made later in the year, thereby increasing the return on investment.

Project Progress Summary:
The engineers and contractors are in the process of reviewing detail design and should be approximately 30% complete by year-end.

Project Projections:
Estimated project expenditures (depreciation and return) for the period January 2005 through December 2005 are expected to be $1,852,914.

FLORIDA POWER & LIGHT COMPANY
PROJECT DESCRIPTION AND PROGRESS

Project Title: Pt. Everglades ESP Technology – Capital
Project No.25
Project Description:
The requirements of the Clean Air Act direct the EPA to develop health-based standards for certain "criteria pollutants". i.e. ozone (O_3), sulfur dioxide (SO_2), carbon monoxide (CO), particulate matter (PM), nitrogen oxides (NOx), an lead (Pb). EPA developed standards for the criteria pollutants and regulates the emissions of those pollutants from major sources by way of the Title V permit program. Florida has been granted authority from the EPA to administer its own Title V program which is at least as stringent as the EPA requirements. Florida is able to, issue, renew and enforce Title V air operating permits for sources within the state via 403.061 Florida Statutes and Chapter 62-213 F.A.C., which is administered by the State of Florida Department of Environmental Protection ("DEP"). The Title V program addresses the six criteria pollutants mentioned earlier, and includes hazardous air pollutants (HAP). The EPA sets the limits of emissions of Hazardous Air Pollutants through the Maximum Achievable Control Technology (MACT). The original Port Everglades Title V permit, issued in 1998, expires on December 31, 2003 and must be renewed. The DEP's Final Title V permit for FPL Port Everglades plant requires FPL to install Electrostatic Precipitators at all four Port Everglades units to address local concerns and to insure compliance with the National Ambient Air Quality Stands and the EPA MACT Standards.

Project Accomplishments:
(January 1, 2004 to December 31, 2004)
The engineering design for Units 1–4 will be completed in 2004. Construction work is on schedule to support the start up of the Unit 2 electrostatic precipitator in the spring of 2005 and the Unit 1 electrostatic precipitator in the fall of 2005.

Project Fiscal Expenditures:
(January 1, 2004 to December 31, 2004)
The variance in depreciation and return is estimated to be $228,739 or 20.9% lower than projected. This variance is due to timing differences - a larger portion of the expenditures being made in the later months of the year which were projected to be made earlier in the year, thereby decreasing the return on investment.

Project Progress Summary:
(January 2004 - December 2004)
The engineering design for Units 1–4 will be completed in 2004. Construction work is on schedule to support the start up of the Unit 2 electrostatic precipitator in the spring of 2005 and the Unit 1 electrostatic precipitator in the fall of 2005.

Project Projections:
Estimated project expenditures (depreciation and return) for the period January 2005 through December 2005 are expected to be $5,741,303.

Form 42-6P

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of the Energy & Demand Allocation % By Rate Class
January 2005 to December 2005

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	63.060%	58.556%	55,334,940,634	10,017,085	10,787,651	1.09230267	1.07281827	59,364,335,282	10,941,689	11,783,380	53.79073%	59.77947%	57.80470%
GS1/GST1	69.973%	59.323%	6,075,542,153	991,175	1,169,108	1.09230267	1.07281827	6,517,952,622	1,082,663	1,277,020	5.90599%	5.91508%	6.26457%
GSD1/GSDT1	77.702%	67.808%	23,085,553,190	3,391,595	3,886,466	1.09220064	1.07274057	24,764,809,488	3,704,302	4,244,801	22.43969%	20.23830%	20.82335%
OS2	93.228%	18.954%	21,113,200	2,585	12,716	1.05829225	1.04657532	22,096,554	2,736	13,457	0.02002%	0.01495%	0.06601%
GSLD1/GSLDT1/CS1/CST1	83.923%	73.179%	10,666,361,079	1,450,879	1,663,887	1.09083728	1.07170069	11,431,146,528	1,582,673	1,815,030	10.35790%	8.64687%	8.90383%
GSLD2/GSLDT2/CS2/CST2	87.158%	77.697%	1,750,619,663	229,288	257,208	1.08297958	1.06544968	1,865,197,160	248,314	278,551	1.69008%	1.35665%	1.36646%
GSLD3/GSLDT3/CS3/CST3	86.580%	74.020%	187,194,635	24,682	28,869	1.02969493	1.02438901	191,760,127	25,415	29,726	0.17376%	0.13885%	0.14582%
ISST1D	96.676%	65.398%	0	0	0	1.09230267	1.07281827	0	0	0	0.00000%	0.00000%	0.00000%
ISST1T	87.151%	34.593%	0	0	0	1.02969493	1.02438901	0	0	0	0.00000%	0.00000%	0.00000%
SST1T	87.151%	34.593%	150,031,028	19,652	49,510	1.02969493	1.02438901	153,690,136	20,236	50,980	0.13926%	0.11056%	0.25009%
SST1D1/SST1D2/SST1D3	96.676%	65.398%	23,594,871	2,786	4,119	1.07224837	1.06763473	25,190,703	2,987	4,417	0.02283%	0.01632%	0.02167%
CILC D/CILC G	92.072%	85.089%	3,469,946,584	430,221	465,526	1.08128023	1.06432600	3,693,154,368	465,189	503,364	3.34641%	2.54154%	2.46931%
CILC T	94.419%	84.681%	1,522,653,717	184,093	205,263	1.02969493	1.02438901	1,559,789,734	189,560	211,358	1.41334%	1.03565%	1.03684%
MET	70.123%	58.555%	96,643,843	15,733	18,841	1.05829225	1.04657532	101,145,061	16,650	19,939	0.09165%	0.09097%	0.09781%
OL1/SL1/PL1	565.360%	48.204%	555,624,734	11,219	131,580	1.09230267	1.07281827	596,084,366	12,255	143,725	0.54012%	0.06695%	0.70506%
SL2	99.953%	96.512%	70,174,667	8,015	8,300	1.09230267	1.07281827	75,284,665	8,755	9,066	0.06822%	0.04783%	0.04447%
TOTAL			103,009,994,000	16,779,008	18,689,044			110,361,636,795	18,303,424	20,384,814	100.00%	100.00%	100.00%

Notes:
(1) AVG 12 CP load factor based on actual load research data
(2) GCP load factor based on actual load research data
(3) Projected KWH sales for the period January 2005 through December 2005
(4) Calculated: (Col 3)/(8,760 * Col 1)
(5) Calculated: (Col 3)/8,760 * Col 2)
(6) Based on 2003 demand losses
(7) Based on 2003 energy losses
(8) Col 3 * Col 7
(9) Col 1 * Col 6
(10) Col 2 * Col 6
(11) Col 8 / total for Col 8
(12) Col 9 / total for Col 9
(13) Col 10 / total for Col 10

Form 42-7P

Florida Power & Light Company
Environmental Cost Recovery Clause
Calculation of Environmental Cost Recovery Clause Factors
January 2005 to December 2005

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	53.79073%	59.77947%	57.80470%	$7,863,703	$5,747,335	$401,919	$14,012,957	55,334,940,634	0.00025
GS1/GST1	5.90599%	5.91508%	6.26457%	$863,401	$568,690	$43,558	$1,475,649	6,075,542,153	0.00024
GSD1/GSDT1	22.43969%	20.23830%	20.82335%	$3,280,473	$1,945,757	$144,786	$5,371,016	23,085,553,190	0.00023
OS2	0.02002%	0.01495%	0.06601%	$2,927	$1,437	$459	$4,823	21,113,200	0.00023
GSLD1/GSLDT1/CS1/CST1	10.35790%	8.64687%	8.90383%	$1,514,228	$831,330	$61,909	$2,407,467	10,666,361,079	0.00023
GSLD2/GSLDT2/CS2/CST2	1.69008%	1.35665%	1.36646%	$247,074	$130,432	$9,501	$387,007	1,750,619,663	0.00022
GSLD3/GSLDT3/CS3/CST3	0.17376%	0.13885%	0.14582%	$25,402	$13,350	$1,014	$39,766	187,194,635	0.00021
ISST1D	0.00000%	0.00000%	0.00000%	$0	$0	$0	$0	0	0.00021
ISST1T	0.00000%	0.00000%	0.00000%	$0	$0	$0	$0	0	0.00022
SST1T	0.13926%	0.11056%	0.25009%	$20,359	$10,629	$1,739	$32,727	150,031,028	0.00022
SST1D1/SST1D2/SST1D3	0.02283%	0.01632%	0.02167%	$3,337	$1,569	$151	$5,057	23,594,871	0.00021
CILC D/CILC G	3.34641%	2.54154%	2.46931%	$489,214	$244,350	$17,169	$750,733	3,469,946,584	0.00022
CILC T	1.41334%	1.03565%	1.03684%	$206,618	$99,570	$7,209	$313,397	1,522,653,717	0.00021
MET	0.09165%	0.09097%	0.09781%	$13,398	$8,746	$680	$22,824	96,643,843	0.00024
OL1/SL1/PL1	0.54012%	0.06695%	0.70506%	$78,960	$6,437	$4,902	$90,299	555,624,734	0.00016
SL2	0.06822%	0.04783%	0.04447%	$9,973	$4,599	$309	$14,881	70,174,667	0.00021
TOTAL				$14,619,065	$9,614,230	$695,304	$24,928,600	103,009,994,000	0.00024

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

(1) From Form 42-6P, Col 11
(2) From Form 42-6P, Col 12
(3) From Form 42-6P, Col 13
(4) Total Energy $ from Form 42-1P, Line 5b x Col 1
(5) Total CP Demand $ from Form 42-1P, Line 5b x Col 2
(6) Total GCP Demand $ from Form 42-1P, Line 5b x Col 3
(7) Col 4 + Col 5 + Col 6
(8) Projected KWH sales for the period January 2005 through December 2005
(9) Col 7 / Col 8 x 100

FLORIDA POWER & LIGHT COMPANY

MARTIN UNIT 8
POWER PLANT SITING APPLICATION
PA 89-27A

FINAL ORDER OF CERTIFICATION AND EXCERPTS FROM CONDITIONS OF CERTIFICATION – SECTION IV - AIR

RRL-1
DOCKET NO. 040007-EI
FPL WITNESS: R. R. LABAUVE
EXHIBIT ______________
PAGES 1-38

STATE OF FLORIDA
SITING BOARD

IN RE:	**FLORIDA POWER & LIGHT COMPANY MARTIN UNIT 8 POWER PLANT SITING APPLICATION NO. PA89-27A.**)	**DOAH CASE NO.**	**02-0573EPP**
		OGC CASE NO.	**02-0197**

FINAL ORDER OF CERTIFICATION

On March 5, 2003, an administrative law judge with the Division of Administrative Hearings ("DOAH") submitted his Recommended Order on site certification in this administrative proceeding. The Recommended Order indicates that copies were served upon counsel for Florida Power & Light Company ("FPL"), Florida Department of Environmental Protection ("DEP"), Martin County, and upon other designated state and regional agencies. A copy of the Recommended Order is attached as Exhibit A. The matter is now before the Governor and Cabinet, sitting as the "Siting Board," for final action under the Florida Electrical Power Plant Siting Act ("PPSA") embodied in §§ 403.501-403.518, Florida Statutes.

BACKGROUND

FPL operates several electrical power plants in this state, including its existing Martin Plant located in an unincorporated area in the western portion of Martin County, Florida (the "Martin Site"). The Martin Site encompasses approximately 11,300 acres of property, a portion of which (2,192 acres) has been previously certified under the PPSA. The area surrounding the Martin Site is primarily agricultural and includes croplands, pastures, groves, wetlands, undeveloped lands, and scattered rural residences. The nearest residence is approximately two miles away from the portion of the Martin Site proposed for site certification in this proceeding.

The existing Martin Plant includes two 800 megawatt (nominal) steam-electric generating units known as Units 1 and 2, two 450 megawatt (nominal) combined cycle generating units known as Units 3 and 4, and two 170 megawatt (nominal) simple cycle combustion turbines known as Units 8A and 8B. FPL applied for permits for Martin Units 1 and 2 prior to 1973. Martin Units 1 and 2, which use residual fuel oil and natural gas, began commercial operation in 1980 and 1981, respectively. Martin Units 3 and 4, which use natural gas and are permitted to burn distillate or "light" oil, were certified under the PPSA in 1991 and began operation in 1994.

RECEIVED
APR 14 2003
Hopping Green Sams & Smith

Units 8A and 8B, which use natural gas and light oil, were approved through modifications of the original site certification in 2000, and began operation in 2001.

On February 1, 2002, FPL filed an application with DEP for site certification with respect to a proposed expansion of the existing Martin Units 8A and 8B ("Unit 8 Project") located at the Martin Site. The Unit 8 Project will utilize approximately 110 acres in the aggregate, all of which acreage is located within the portion of the Martin Site previously certified under the PPSA. However, only approximately 15.5 acres will be occupied by the Unit 8 power block. The Unit 8 Project proposes to combine the two existing combustion turbines (Units 8A and 8B) at the Martin Site, add two new combustion turbines, four heat recovery steam generators (one for each combustion turbine), and one new steam turbine electric generator. The Unit 8 Project also includes two new electrical transmission lines and an optional cooling tower. Natural gas will be the primary fuel for the Unit 8 generating facilities, and light oil will be used as an alternate fuel. When completed and placed in operation, the Unit 8 generating facilities will increase the total installed generating capacity of the Martin Plant by approximately 800 megawatts. The Florida Public Service Commission ("PSC") issued an order on December 10, 2002, determining the need for the Unit 8 Project.

DOAH PROCEEDINGS

DEP forwarded the matter of FPL's requested site certification for the Unit 8 Project to DOAH for formal administrative proceedings, and Administrative Law Judge Charles A. Stampelos ("ALJ") was assigned to the case. In May of 2002, the ALJ conducted a land use hearing in this case as required by the PPSA. The ALJ entered a subsequent Recommended Land Use Order concluding that the site of the Unit 8 Project is consistent and in compliance with the land use plans and zoning ordinances of Martin County. On August 13, 2002, the Siting Board entered an order adopting the ALJ's Recommended Land Use Order and determining that the site of the Unit 8 Project is consistent and in compliance with the land use plans and zoning ordinances of Martin County.

On December 20, 2002, DEP issued its written Staff Analysis Report concerning the Unit 8 Project. DEP's Report contained a compilation of proposed Conditions of Certification for the Unit 8 Project. DEP's Report also included reports from other state, regional, and local agencies. On February 10, 2003, a Joint Prehearing Stipulation was submitted to the ALJ indicating that no party to this administrative proceeding objected to certification of the Unit 8 Project. The parties joining in the Prehearing Stipulation included FPL, DEP, Martin County, the PSC, the Florida Department of Community Affairs, the Florida Fish and Wildlife Conservation Commission, the Florida Department of Transportation, and the South Florida Water Management District. Pursuant to § 403.508(3), Florida Statutes, the ALJ held a formal administrative hearing on site certification of the Unit 8 Project in Indiantown on February 17, 2003. Expert testimony and other evidence in support of site certification were presented at this hearing by FPL and DEP. Three members of the general public also testified at the certification hearing, but none of them spoke in opposition to the Unit 8 Project.

RECOMMENDED ORDER

On March 5, 2003, the ALJ entered his Recommended Order on site certification of the Unit 8 Project. Included in the Recommended Order, is the ALJ's basic conclusion that FPL met its burden of proof of demonstrating at the certification hearing that the Unit 8 Project, including the proposed transmission line corridor, complies with all the criteria for certification under the PPSA. The ALJ specifically concluded that the unrebutted evidence at the hearing demonstrated that the Unit 8 construction and operation safeguards are sufficient to protect the public welfare. The ALJ further concluded that the Project will result in minimal adverse affects on human health, the environment, the ecology of the land and its wildlife, and the ecology of state waters and their aquatic life. The ALJ ultimately recommended that the Siting Board "grant full and final certification" of the Martin Unit 8 Project.

CONCLUSION

No Exceptions were filed in this administrative proceeding challenging any of the ALJ's findings or conclusions in the Recommended Order on site certification. Furthermore, the record in this proceeding is devoid of objections by any governmental agencies to site certification of the Unit 8 Project. Based on a review of the record and the governing law, the Siting Board concludes that FPL's Unit 8 Project complies with the certification requirements of the PPSA and that site certification of the Project, including the associated transmission line facility, will fully balance the increasing demand for electrical power plant location and operation in this State with the broad interests of the public that are protected by the PPSA.

It is therefore ORDERED that:

A. The following clarifying corrections are made to the Conditions of Certification for the Martin Expansion Project incorporated by reference in the Recommended Order:

1. Condition of Certification I.A. is revised to read as follows:

A. Pursuant to s. 403.501-518, F.S., the Florida Electrical Power Plant Siting Act, this certification is issued to Florida Power and Light Company (FPL) owner/operator of the Martin Power Plant. Under the control of these Conditions of Certification, FPL will operate the Martin Expansion Project consisting of two natural gas-fired Combined Cycle Units No. 3 and No. 4 (each 450 MW nominal), and two simple cycle Units 8A and 8B (each 170 MW nominal) which will be incorporated into Unit 8, a "4 on 1" Combined Cycle Gas Turbine facility (total 1100 MW nominal) and ancillary equipment. The Martin Expansion Project includes future facilities, namely two gas-fired Combined Cycle Units No. 5 and No. 6, and a coal gasification facility; those future facilities will require approval in subsequent proceedings under the Act. These units are located on an 11,300-acre site located in Sections 29 & 30/Township 39 South/Range 37 East in southwestern Martin County.

2. Condition of Certification III.8 is revised to read as follows:

8. "Project" shall mean the Martin Expansion Project and all associated facilities, including: Units 3 and 4, Units 8A and 8B, Combined Cycle Unit 8, coal and limestone handling and related facilities, the cooling pond, gas pipeline, supplemental cooling tower, transmission lines and related facilities. The project consists of four phases. Phase I involved natural gas-fired, combined cycle Units 3 and 4 with distillate fuel oil as backup and an associated natural gas pipeline and transmission line upgrade. Phase II involves incorporation of Units 8A and 8B into combined-cycle Unit 8. Phase III involves Units 5 and 6 fueled by natural gas or onsite coal gasification facilities, with distillate fuel oil and natural gas as backup. Phase IV consists of coal gasification facilities. Phases III and IV will require approval in subsequent proceedings under the Act.

B. The Recommended Order on site certification (Exhibit A) is adopted and incorporated by reference herein.

C. Certification of the location, construction, and continued operation of the Martin Unit 8 Project as described in FPL's site certification application and by the evidence presented at the certification hearing is APPROVED, subject to the Conditions of Certification contained in DEP Exhibit 2, as revised in Paragraph A above.

D. Authority to assure and enforce compliance by FPL and its agents with all of the Conditions of Certification imposed by this Final Order is hereby delegated to DEP, except that any proposed modification to burn a fuel other than natural gas or light oil shall be reviewed by the Siting Board.

Any party to this proceeding has the right to seek judicial review of the Final Order pursuant to Section 120.68, Florida Statutes, by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the clerk of the Department in the Office of General Counsel, 3900 Commonwealth Boulevard, M.S. 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 this Final Order is filed with the clerk of the Department.

DONE AND ORDERED this 11 day of April, 2003, in Tallahassee, Florida, pursuant to a vote of the Governor and Cabinet, sitting as the Siting Board, at a duly noticed and constituted Cabinet meeting held on April 8, 2003.

THE GOVERNOR AND CABINET
SITTING AS THE SITING BOARD

Jeb Bush

THE HONORABLE JEB BUSH
GOVERNOR

FILING IS ACKNOWLEDGED ON THIS DATE, PURSUANT TO § 120.52 FLORIDA STATUTES, WITH THE DESIGNATED DEPARTMENT CLERK, RECEIPT OF WHICH IS HEREBY ACKNOWLEDGED

Kathy Carter 4/14/03
CLERK DATE

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing Final Order has been sent by United States Postal Service to:

Peter C. Cunningham, Esquire
Douglas S. Roberts, Esquire
Hopping Green & Sams, P.A.
Post Office Box 6526
Tallahassee, FL 32314

Ross Stafford Burnaman, Esquire
Fish and Wildlife Conservation Commission
6230 South Meridian Street
Tallahassee, FL 32399-1600

Robert V. Elias, Esquire
Florida Public Service Commission
Gerald Gunter Building
2450 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Ann Cole, Clerk and
Charles A. Stampelos, Administrative Law Judge
Division of Administrative Hearings
The DeSoto Building
1230 Apalachee Parkway
Tallahassee, FL 32399-1550

Roger Saberson, Esquire
Treasure Coast Regional Planning Council
70 Southeast Fourth Avenue
Delray Beach, FL 33483-4514

Tyson Waters, Esquire
Krista Storey, Esquire
Martin County Attorney's Office
2401 Southeast Monterey Road
Stuart, FL 34996

Colin Roopnarine, Esquire
Department of Community Affairs
2555 Shumard Oak Boulevard
Tallahassee, FL 32399-2100

Susan Roeder Martin, Esquire
Assistant General Counsel
S. F. Water Management District
Post Office Box 24680
West Palm Beach, FL 33416

Sheauching Yu, Esquire
Department of Transportation
Haydon Burns Building
605 Suwannee Street
Mail Station 58
Tallahassee, FL 32399-0450

and by hand delivery to:

Scott A. Goorland, Esquire
Department of Environmental Protection
3900 Commonwealth Blvd.
Mail Station 35
Tallahassee, FL 32399-3000

this 14th day of April, 2003.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

J. TERRELL WILLIAMS
Assistant General Counsel

3900 Commonwealth Blvd., M.S. 35
Tallahassee, FL 32399-3000
Telephone 850/245-2242

FLORIDA POWER AND LIGHT COMPANY
MARTIN EXPANSION PROJECT
PA 89-27

CONDITIONS OF CERTIFICATION

I. ~~GENERAL~~ CERTIFICATION CONTROL

A. Pursuant to s. 403.501-518, F.S., the Florida Electrical Power Plant Siting Act, this certification is issued to Florida Power and Light Company (FPL) owner/operator of the Martin Power Plant. Under the control of these Conditions of Certification the FPL will operate the Martin Expansion Project including a 1,000 MW (nominal) facility consisting of two natural gas-fired Combined Cycle **Units No. 3 and No. 4**, two simple cycle **Units 8A and 8B** which will be incorporated into **Unit 8** a "4 on 1" Combined Cycle Gas Turbine facility and ancillary equipment. The Martin Expansion Project includes future facilties, given preliminary approval, namely two gas-fired Combined Cycle **Units No. 5 and No. 6** and potentially a coal gasification facility. These units are located on a 11,300-acre site located in Sections 29&30/Township 39 South/Range 37 East in southwestern Martin County;

B. The general and specific conditions contained in these Conditions of Certification, unless specifically amended or modified, are binding upon the permittee and shall apply to the construction and operation of the certified facility. If a conflict should occur between the design criteria of this project and the Conditions of Certification, the Conditions shall prevail unless amended or modified.

II. APPLICABLE RULES

The construction and operation of the certified facility shall be in accordance with all applicable provisions of Florida Statutes and Department and Water Management District rules, including the following regulations: [South Florida WMD: 40E-2, 40E-3, 40E-4, 40E-6, 40-E20] 62-4, 62-17, 62-256, 62-296, 62-297, 62-301, 62-302, 62-531, 62-532, 62-550, 62-555, 62-560, 62-600, 62-601, 62-604, 62-610, 62-620, 62-621, 62-650, 62-699, 62-660, 62-701, and 62-814, Florida Administrative Code (F.A.C.), or their successors as they are renumbered, as these regulations existed on the date of the certification of a specific phase, or as they may become applicable pursuant to subsection 403.511 5(a), F.S.

III. Definitions

Unless otherwise indicated herein, ~~T~~the meaning of the terms used herein shall be governed by the definitions contained in Chapters 403, 378, 373, and 253, Florida Statutes and any regulation adopted pursuant thereto and the statutes and regulations of any agency. In the event of any dispute over the meaning of a term used in these conditions which is not defined in such statutes or regulations, such dispute shall be resolved by reference to the most relevant definition contained in any other state or federal statute or regulation or, in the alternative, by the use of the commonly accepted meaning as determined by the Department of Environmental Protection~~. As used herein~~ In addition, the following words shall have the indicated meanings:

1. "Application" shall mean the Site Certification Applications for the Martin Coal Gasification/Combined Cycle Project, ~~and~~ peaking units 8A and 8B and Combined Cycle Unit 8 as supplemented.

2. "DEP" shall mean the Florida Department of Environmental Protection.

3. "Emergency conditions" shall mean urgent circumstances involving potential adverse consequences to human life or property as a result of weather conditions or other calamity, and necessitating new or replacement operating equipment, gas pipeline, transmission lines, or access facilities.

4. "Feasible" or "practicable" shall mean reasonably achievable considering a balance of land use impacts, environmental impacts, engineering constraints, and costs.

5. "FFWCC" shall mean the Florida Fish and Wildlife Conservation Commission.

6. "Permittee" shall mean Florida Power and Light Company (FPL) as owner and operator of the certified facility.

7. "Power plant" shall mean the electric power generating equipment and appurtenances to be constructed on the certified portion of the Martin site in Martin County, as generally depicted in the Application.

8. "Project" shall mean the Martin Expansion Project and all associated facilities, including: Units 3 and 4, Units 8A and 8B, Combined Cycle Unit 8, coal and limestone handling and related facilities, the cooling pond, gas pipeline, supplemental cooling tower, transmission lines and related facilities. The project consists of four phases. Phase I involved natural gas-fired, combined cycle Units 3 and 4 with distillate fuel oil as backup and an associated natural gas pipeline and transmission line upgrade. Phase II involves combined-cycle Unit 8. Phase III involves Units 5 and 6 fueled by natural gas or onsite coal gasification facilities, with distillate fuel oil and natural gas as backup. Phase IV consists of coal gasification facilities.

9. "SFWMD" shall mean the South Florida Water Management District.

10. "ISO" shall mean International Organization for Standardization, ISO 3977-1978(E) standard conditions for gas turbines = 14.7 psia, 150° C, relative humidity 60%.

11. "Facility" shall mean the certified electrical power generation facility and all associated structures, including but not limited to: combustion turbine generators, heat recovery steam generators, duct burners, steam turbine generators, selective catalytic reduction units, transformers, associated transmission lines, substations, fuel and water storage tanks, natural gas delivery metering station, air and water pollution control equipment, storm water control ponds and facilities, cooling towers, and related structures.

12. "DHR" shall mean the Florida Department of State, Division of Historical Resources.

13. "NPDES permit" shall mean the federal National Pollutant Discharge Permit System permit issued in accordance with the federal Clean Water Act.

14. "PSD permit" shall mean the federal Prevention of Significant Deterioration air emissions permit issued in accordance with the federal Clean Air Act.

15. "Title V permit" shall mean the federal permit issued in accordance with Title V of the federal Clean Air Act.

16. "The SE District Office" shall mean the Department's Southeast District Office located at 400 North Congress Avenue, West Palm Beach, FL 33401, (561) 681-6600.

~~A. Applicable Rules~~

~~The construction and operation of the Martin CG/CC Project shall be in accordance with all applicable provisions of at least the following regulations of DEP: Chapters 62-4, 62-17, 62-256, 62-296, 62-297, 62-301, 62-302, 62-531, 62-532, 62-550, 62-555, 62-560, 62-600, 62-601, 62-604, 62-610, 62-620, 62-621, 62-650, 62-660, 62-701, 62-762, 62-767, 62-769, 62-770, 62-814, 62-699, and 62-25, Florida Administrative Code (F.A.C.) or their successors as they are renumbered.~~

~~II~~ IV. AIR

The construction and operation of Martin Expansion Project shall be in accordance with all applicable provisions of Chapters 62-204, 62-210, 62-212, 62-296, and 62-297, F.A.C. In addition to the foregoing, the project shall comply with the General Requirements, Testing Requirements, Records and Reports requirements of PSD Permits PSD-FL-286 and FL 327, as may be subsequently modified, and the following conditions of certification as indicated. (The following emission limitations and conditions in paragraph ~~II~~ IV.A. reflect final BACT determinations, as determined by the Department under the PSD review, for Units 3 and 4 and preliminary determinations for Units 5 and 6; paragraph ~~II~~ IV.B. are for simple cycle units 8A and 8B; and Paragraph ~~II~~ IV.C. is for Unit 8 in the combined cycle mode firing natural gas and oil. However, emission limitations in this certification do not establish BACT. Emission limitations and conditions concerning phases III and IV of the project were preliminary based on information furnished by the Permittee in order to support certification of ultimate site capacity and shall be determined finally upon review of supplemental applications.)

A. Emission Limitations for Martin CG/CC Project - Units 3 and 4

1. The maximum heat input to each CT shall neither exceed 1,966 MMBtu/hr while firing natural gas, nor 1,846 MMBtu/hr while firing fuel oil (@ 40°F). For coal derived gas firing the maximum heat input to each CT shall not exceed 2,100 MMBtu/hr (@ 75°F). These heat input limitations are subject to change. Any changes shall be provided at least 90 days before commercial operation for each fuel available to the site which a unit is capable of firing, at which time this condition may be modified, after proper notice, to reflect those parameters. Each combined cycle unit's fuel consumption shall be continuously determined and recorded.

2. Each of the eight combustion turbines (CTs) may operate continuously, i.e., 8,760 hrs/year.

3. Only natural gas, light distillate fuel oil, or coal derived gas shall be fired in the combustion turbines.

4. The maximum allowable emissions from each CT in accordance with the BACT determination, shall not exceed the following, at 40°F (except during periods of startup and shutdown and except as provided in Condition ~~II~~ IV.A.22.):

Emission Limitations[d]

Pollutant	Fuel	Basis	Units 3 & 4		Units 5 & 6	
			lb/hr/CT	TPY[a]	Lb/hr/CT	TPY[a]
NOx	Gas	25 ppmvd @ 15% O_2	177	comb. tot. 3108	177	comb. tot. 3108
	Oil	65 ppmvd @ 15% O_2	461		461	
	CG	42 ppmvd @ 15% O_2	392	6868	392	6868
VOC[b]	Gas	1.6 ppmvd	3	comb. tot. 57	3	comb. tot. 57
	Oil	6 ppmvd	11		11	
	CG	9 ppmvd	21.4	375	21.4	375
CO	Gas	30 ppmvd	94.3	comb. tot. 871	94.3	comb. tot. 871
	Oil	33 ppmvd	105.8		105.8	
	CG	33 ppmvd	134	2311	134	2311
PM/ PM_{10}	Gas		18	comb. tot. 100	18	comb. tot. 100
	Oil		60.6		60.6	
	CG		19	333	19	333
Pb	Gas		neg.	comb. tot. 0.015	neg.	comb. tot. 0.015
	Oil		0.015		0.015	
	CG		0.3	5.3	0.3	5.3
SO_2	Gas		91.5	comb. tot. 568	91.5	comb. tot. 568
	Oil		920		920	
	CG		834	14612	834	14612

a. Tons per year (TPY) emission limits listed for natural gas and oil combined apply as an emission cap based on limiting oil firing to an annual aggregate of 2,000 hours for the 4 CTs, with compliance to be demonstrated in annual operation reports.

b. Exclusive of background concentrations.

c. Sulfur dioxide emissions based on a maximum of 0.5 percent sulfur in oil for hourly emissions and an average sulfur content of 0.3 percent for annual emissions.

d. These limitations for Units 5 and 6 and coal gasification shall not be binding for subsequent BACT determinations.

e. The excess emissions authorized under Rule 17-210.700(1), F.A.C., shall be extended an additional two hours (for a total not to exceed four hours) for a cold turbine start for the first CT of a CC unit. The second CT of each CC unit shall comply with Rule 17-210.700(1), F.A.C.

5. The following emissions~~, determined by BACT,~~ are tabulated for PSD and inventory purposes:

Maximum Allowable Emissions (@ 40°F)

Pollutant	Fuel	Units 3 & 4		Units 5 & 6	
		lb/hr/CT	TPY[a]	lb/hr/CT	TPY[a]
H_2SO_4[b] Acid Mist	Gas	11.2	Comb. tot. 70	11.2	comb. tot. 70
	Oil	113		113	
	CG	102	1787	102	1787
Mercury	Gas	0.021	Comb. tot. 0.34	0.021	comb. tot. 0.34
	Oil	0.0052		0.0052	
	CG	0.024	0.42	0.024	0.42
Fluoride	Oil	0.055	0.055	0.055	0.055
Beryllium	Oil	0.004	0.004	0.004	0.004

a. Tons per year (TPY) emission limits listed for natural gas and oil combined apply as an emission cap based on limiting oil firing to an annual aggregate of 2,000 hours for the 4 CTs, with compliance to be demonstrated in annual operation reports.

b. Sulfuric acid mist emissions assume a maximum of 0.5 percent sulfur in fuel oil for hourly emissions and an average sulfur content of 0.3 percent for annual emissions.

6. The maximum allowable emissions from each gasifier incinerator stack shall not exceed the following at 75° F:

Pollutant	Lb/hr/Stack	TPY/Stack	4 Stacks
Nox	61	268	1069
VOC	Negl.	Negl.	Negl.
CO	Negl.	Negl.	Negl.
PM/PM_{10}	Negl.	Negl.	Negl.
SO_2	32	140.2	555
Beryllium	0.0005	0.002	0.008
Mercury	0.008	0.035	0.140
Lead	0.05	0.22	0.88

7. Auxiliary Steam Boilers and Diesel Generators shall operate only during start-up and shut down, periodic maintenance testing, and for emergency power generation, respectively. NOx emissions for the auxiliary steam boilers shall not exceed

0.3 lb/MMBtu for natural gas firing or for oil firing. NOx emissions for the diesel generators shall not exceed 15.0 grams/hp-hr. Sulfur dioxide emissions limitations for the auxiliary steam boilers and diesel generators are established by firing natural gas or limiting the light distillate fuel oil's sulfur content to 0.3% on an annual basis.

8. Visible emissions shall neither exceed 10% opacity while burning natural gas or coal derived gas, nor 20% opacity while burning distillate oil.

9. Nitrogen oxide emissions from each gas turbine/heat recovery steam generator unit shall be controlled by using dry low NOx combustors for natural gas with steam injection for fuel oil firing. The Permittee shall install duct module(s) suitable for future installation of SCR equipment on each combined cycle generating unit.

10. Initial (I) compliance tests shall be performed on each Combustion Turbine using both fuels. The stack test for each turbine shall be performed within 10% of the maximum heat rate input for the tested operating temperature. Annual (A) compliance tests shall be performed on each Combustion Turbine with the fuel(s) used for more than 400 hours in the preceding 12 month period. Tests shall be conducted using EPA reference methods in accordance with the November 2, 1989, version of 40 CFR 60 Appendix A:

a. 5 or 17 for PM (I, A, for oil only)
b. 8 for sulfuric acid mist (I, for oil only)
c. 9 for VE (I, A)
d. 10 for CO (I, A)
e. 20 for NOx (I, A)
f. 18 for VOC (I, A)
g. Trace elements of Lead (Pb) and Beryllium (Be) shall be tested (I for oil only) using EMTIC Interim Test Method. As an alternative, Method 104 for Beryllium (Be) may be used; or Be and Pb may be determined from fuel analysis using either Method 7090 or 7091, and sample extraction using Method 3040 as described in the EPA solid waste regulations SW 846.
h. ASTM D 2880-71 (or equivalent) for sulfur content of distillate oil (I, A)
i. ASTM D 1072-80, D 3031-81, D 4084-82 or D 3246-81 (or equivalent) for sulfur content of natural gas (I, and A if deemed necessary by DEP)
j. Mercury (Hg) shall be tested using EPA Method 101 (40 CFR 61, Appendix B) (I)

Other DEP approved methods may be used for compliance testing after prior Departmental approval.

11. The average annual sulfur content of the light distillate fuel oil shall not exceed 0.3% by weight. The maximum sulfur content of the light distillate fuel oil shall not exceed 0.5%. Compliance shall be demonstrated in accordance with the requirements of 40 CFI 60.334 by testing for sulfur content of oil storage tanks once per day when firing oil using ASTM D 2880-71, testing for nitrogen content, and testing for heating value.

12. Continuous emission monitoring shall be installed, operated, and maintained in accordance with 40 CFR 60, Appendix F, for each combined cycle unit to monitor nitrogen oxides.

a. Each continuous emission monitoring system (CEMS) shall meet performance specifications of 40 CFR 60, Appendix B.

b. CEMS data shall be recorded and reported in accordance with Chapter 17 2, F.A.C., and 40 CFR 60. The record shall include periods of startup, shutdown and malfunction.

c. A malfunction means any sudden and unavoidable failure of air pollution control equipment or process equipment to operate in a normal or usual manner. Failures that are caused entirely or in part by poor maintenance, careless operation or any other preventable upset condition or preventable equipment breakdown shall not be considered malfunctions.

d. The procedures under 40 CFR 60.13 shall be followed for installation, evaluation and operation of all CEMS.

e. For purposes of reports required under this certification, excess emissions are defined as any calculated average emission concentration, as determined pursuant to Condition # IV.A.18 herein, which exceeds the applicable emission limits in Condition # IV.A.4.

13. To determine compliance with the oil firing heat input limitation, the Permittee shall maintain daily records of fuel oil consumption and hourly usage for each turbine and heating value for such fuel. All records shall be maintained for a minimum of three years after the date of each record and shall be made available to representatives of the Department upon request.

14. The source shall be in compliance with all requirements of 40 CFR 60 Subpart GG, (Standards of Performance for Stationary Gas Turbines) and Rule 62-204.800(7), F.A.C. (Standard of Performance for New Stationary Sources (NSPS)).

a. Natural Gas

Pursuant to 40 CFR 60.334(b)(2), a custom fuel monitoring schedule shall be followed for the natural gas fired at this facility and shall be as follows:

Custom Fuel Monitoring Schedule for Natural Gas

i. Monitoring of fuel nitrogen content shall not be required if NG is the only fuel being fired in the turbines.

ii. Sulfur Monitoring

(a.) Analysis for fuel sulfur content of the natural gas shall be conducted using one of the approved ASTM reference methods for measurement of sulfur in gaseous fuels, or an approved alternative method. The reference methods are ASTM D1072-80, ASTM D3031-81, ASTM D3246-81, and ASTM D4084-82 as referenced in 40 CFR 60.335, or the latest edition(s).

(b) This custom fuel monitoring schedule shall become effective on October 14, 1997. Effective the date of this custom schedule, sulfur monitoring shall be conducted twice monthly for six months. If this monitoring shows little variability in the fuel sulfur content, and indicates continuous compliance with 40 CFR 60.333, then sulfur monitoring shall be conducted once per quarter for six quarters. If monitoring data is provided by the applicant which demonstrates consistent compliance with the requirements herein, the applicant may begin monitoring as per the requirements of ii(c).

(c) If after the monitoring required in item ii(b) above, or herein, the sulfur content of the fuel shows little variability and calculated as sulfur dioxide, represents consistent compliance with the sulfur dioxide emission limits specified under 40 CFR 60.333, sample analysis shall be conducted twice per annum. This monitoring shall be conducted during the first and third quarters of each calendar year.

(d) Should any sulfur analysis as required in items ii(b) or ii(c) above indicate noncompliance with 40 CFR 60.333, the owner or operator shall notify the Department of such excess emissions and the custom schedule shall be re-examined. ~~by the Environmental Protection Agency.~~ Sulfur monitoring shall be conducted weekly during the interim period when this schedule is being re-examined.

iii. If there is a change in the fuel supply, the owner or operator must notify the Department of such change for re-examination of this custom schedule. A substantial change in fuel quality shall be considered as a change in the fuel supply. Sulfur monitoring shall be conducted weekly during the interim period when this custom schedule is being re-examined.

iv. Records of sample analysis and fuel supply pertinent to this custom schedule shall be retained for a period of five years, and be available for inspection by personnel of federal, state, and local air pollution control agencies.

b. New No. 2 Fuel Oil

The records of new No. 2 fuel oil usage shall be kept by the company for a five year period for regulatory inspection purposes. For sulfur dioxide, periods of excess emissions shall be reported if the fuel oil being fired in the gas turbine exceeds 0.5 percent sulfur content and 0.3 percent sulfur content, by weight, for hourly and annual emissions, respectively.

15. Any change in the method of operation, fuels, or equipment, shall be submitted for approval to DEP's Bureau of Air Regulation.

16. The Permittee shall have required sampling tests of the emissions performed within 60 days after achieving the maximum turbine firing rate, but not later than 180 days from the start of operation. Thirty (30) days notice prior to the initial sampling test and fifteen (15) days notice before subsequent annual testing shall be provided to the Southeast District Office. Written reports of the tests shall be submitted to the Southeast District Office within 45 days of test completion.

17. If construction does not commence on Phase I within 18 months of issuance of this certification/permit, then the Permittee shall obtain from DEP a review and, if necessary, a modification of the control technology and allowable emissions for the unit(s) on which construction has not commenced (40 CFR 5.2l(r)(2)). Units to be constructed or modified in later phases of the project will be reviewed and limitations revisited under the supplementary review process of the Power Plant Siting Act.

18. Quarterly excess emission reports, in accordance with the November 2, 1989, version 40 CFR 60.7(c) and 60.334(c) shall be submitted to DEP's Southeast District office. Annual reports shall be submitted to the District Office in accordance with Rule 62-210.370(3)(c), F.A.C.

19. Literature of equipment selected shall be submitted as it becomes available. A CT-specific graph of ambient temperature and heat inputs to the CT shall be submitted to DEP's Southeast District Office and the Bureau of Air Regulation.

20. Stack sampling facilities shall be provided for each of the CT and incinerator stacks.

21. Construction period fugitive dust emissions shall be minimized by covering or watering dust generation areas.

22. FPL may alter the DIM II combustors for the four CTs subject to these conditions, operate the CT receiving the first altered DIM II combustor for a maximum period of 60 days for adjustment; and, operate each of the other three CTs for a maximum period of 30 days, after installation of the altered DIM II combustors, for adjustment provided the following conditions are met:

a. The Department's Southeast District Air Program Administrator shall be notified in writing a minimum of 10 days in advance of initially placing any altered DIM II combustor into service.

b. To allow time for evaluation and testing of alterations to the dry low NOx combustor (DIM) design, the emission limitations in Specific Condition 4 of the referenced permit shall not apply a sixty (60) day period following installation of the final DIM design configuration in the initial CT and shall not apply during a thirty (30) day period per CT following installation of the final DIM design in each of the remaining three CTs. During the evaluation and testing of the altered combustors, the maximum nitrogen oxides (NOx) emissions shall comply with the emission limit specified by the new source performance standards for CT, 40 CFR 60, Subpart GG. The annual allowable emissions (TPY) of NOx for each CT in permit PSD-FL-146 and these conditions shall not be exceeded.

c. Except during CT performance testing for extreme conditions, carbon monoxide (CO) emissions shall not exceed 100 ppmvd. The maximum CO emissions during a 12 hour test period to evaluate CT performance during extreme conditions shall not exceed 500 ppmvd, 30 minute average. The annual allowable emissions (TPY) of CO for each CT in permit PSD-FL-146 and these conditions shall not be exceeded.

d. The volatile organic compound (VOC) emissions shall not exceed 20 ppmvd except during CT performance testing for extreme conditions. During the 12 hour test period to evaluate CT performance during extreme conditions, VOC emissions shall not exceed 100 ppmvd. The annual allowable emissions (TPY) of VOC from each CT in permit PSD-FL-146 and these conditions shall not be exceeded. The VOC emissions shall be evaluated during the testing periods by measuring total unburned hydrocarbons (UHC). FPL shall determine the VOC component of UHC emissions at several different UHC levels during the testing of the first combustion turbine to have the new DIM II combustors installed. The ratio of VOC/UHC concentration shall be measured, as a minimum, at the low, medium, and high UHC concentration observed during the CT performance tests. The VOC component of the UHC emissions shall be attributed against the annual 57 ton VOC emission limit for the facility. The UHC levels shall not exceed 40 ppmvd during the test period. However, during the 12-hour non-continuous CT performance testing for extreme conditions, UHC emissions shall not exceed 500 ppmvd.

e. After the adjustment period, each CT must be in compliance with all limitations in the condition ~~II~~ IV.A.4.

f. Within 45 days after the completion of the project, the permittee shall furnish the Department with a report summarizing the variation in parameters and emissions of NOx, VOC, and CO from the modified DIM II on all of the CTs and any operation problems with the CT units remaining to be resolved.

B. Emissions and Controls for CTs 8A and 8B [Emissions Units 011 and 012] In simple Cycle Mode.

The following conditions in this section apply in accordance with PSD permit No. PSD-FL-286 until commencement of steam blows on Unit 8 "4 on1" Combined Cycle per PSD Permit No. PSD-FL-327.

1. NSPS Requirements: Each combustion turbine shall comply with all applicable requirements of 40 CFR 60, adopted by reference in Rule 62-204.800(7)(b), F.A.C.

2. Combustion Turbines: The permittee is authorized to install, tune, operate and maintain two new General Electric Model PG7241(FA) combustion turbines [Emission Units 011 and 012] with electrical generator sets, each designed to produce a nominal 170 MW of electrical power.

3. Permitted Capacity: The heat input rates (HHV) to each combustion turbine shall not exceed the following: Normal Gas Firing:

(a) 1860 mmBTU per hour with a compressor inlet air temperature of 35° F and producing a maximum 182 MW.

(b) Gas Firing With Power Augmentation (Steam Injection): 1800 mmBTU per hour of natural gas with a compressor inlet air temperature of 59° F and producing a maximum 180 MW.

(c) Gas Firing With Peaking: 1920 mmBTU per hour with a compressor inlet air temperature of 35° F and producing a maximum 190 MW.

(d) Distillate Oil Firing: 2008 mmBTU per hour with a compressor inlet air temperature of 35° F and producing a maximum 191 MW.

The heat input rates are based on the higher heating values (HHV) of 23,127 BTU/lbm for natural gas and 19,490 BTU/lbm for distillate oil. The permittee shall provide the manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Heat input rates will vary depending upon ambient conditions and the combustion turbine characteristics. Compliance shall be determined by data compiled from the automated gas turbine control system. This data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Design; Rule 62-210.200(PTE), F.A.C.]

4. Simple Cycle Operation Only: Each combustion turbine shall operate only in simple cycle mode. This restriction is based on the permittee's request, which formed the basis of the CO and NOx BACT determinations in the PSD and resulted in the emission standards specified in ~~this permit~~ these Conditions of Certification.

Specifically, the CO and NOx BACT determinations in the PSD eliminated several control alternatives based on technical considerations due to the elevated temperatures of the exhaust gas as well as costs related to operation as peaking units. Any request to convert these units to combined cycle operation or increase the allowable hours of operation shall be accompanied by a revised CO and NOx BACT analysis and the approval of the Department through a permit modification in accordance with Chapters 62-210 and 62-212, F.A.C. Note: The results of this analysis may validate the initial BACT determinations or result in the submittal of a full PSD permit application, new control equipment, and new emissions standards. [Applicant Request; Rules 62-210.300 and 62-212.400, F.A.C.]

5. Allowable Fuels: Each combustion turbine shall be designed and tuned for a primary fuel of pipeline-quality natural gas containing no more than 1 grain of sulfur per 100 dry standard cubic feet of gas. As a backup fuel, each combustion turbine may be fired with low sulfur No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. No other fuels are authorized by ~~this permit~~ these Conditions of Certification. It is noted that both limitations are much more stringent than the sulfur dioxide limitation in 40 CFR 60, NSPS Subpart GG and assures compliance with regulations 40 CFR 60.333 and 60.334 of this subpart. The permittee shall demonstrate compliance with the fuel sulfur limits by keeping the records specified in ~~this permit~~ these Conditions. [Application; Rule 62-210.200(PTE), F.A.C.]

6. Alternate Gas Firing Methods of Operation

(a) Power Augmentation Mode: In accordance with the manufacturer's recommendations, steam may be injected into each combustion turbine when firing natural gas to provide additional peaking power during periods of high electrical power demand. Each unit shall not exceed 400 hours of power augmentation during any consecutive 12 months. To qualify as "power augmentation mode", the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions. Prior to activating and after deactivating the power augmentation mode, the operator shall log the date, time, and new mode of operation. Power augmentation when firing distillate oil is prohibited.

(b) High Temperature Peaking Mode: In accordance with the manufacturer's recommendations, each combustion turbine may be operated in a high temperature peaking mode when firing natural gas to provide additional power during periods of peak electrical power demands. Peaking is achieved through the automated gas turbine control system by allowing slightly higher exhaust temperatures, calculating a new combustion reference temperature for the peak load, and adjusting the fuel distribution between the fuel nozzles to maintain lean pre-mix firing. During the transfer from base load to peak load and during peak load operation, each unit will remain in the per-mix steady state mode. Each unit shall not exceed 60 hours of peaking during any consecutive 12 months. To qualify as "peaking mode", the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions. Prior to activating and after deactivating the peaking mode, the operator shall log the date, time, and new mode of operation. Peaking when firing distillate oil is prohibited.

Rules 62-4.070(3) and 62-212.400, F.A.C. (BACT)]

7. Restricted Operation

(a) Gas Firing: Each combustion turbine shall fire no more than 5,902,588,000 standard cubic feet of natural gas during any consecutive 12 months (equivalent to 3390 hours per year at the maximum firing rate for a compressor inlet air temperature of 59° F).

(b) Oil Firing: Each combustion turbine shall fire no more than 7,358,350 gallons of distillate oil during any consecutive 12 months (equivalent to 500 hours per year at the maximum firing rate for a compressor inlet temperature of 59° F). If oil is fired, the natural gas consumption limit shall be reduced by 118 standard cubic feet of gas for every gallon of distillate oil fired.

The permittee shall install, calibrate, operate and maintain a monitoring system for each combustion turbine to measure and accumulate the quantity of fuel and hours of operation for each method of operation. [Applicant Request; Rules 62-212.400(BACT) and 62-210.200(PTE), F.A.C.]

8. Operating Procedures: ~~The Best Available Control Technology (BACT) determinations established by this permit rely on~~ In order to insure that "good operating practices" are used to minimize emissions~~. Therefore~~, all operators and supervisors shall be properly trained to operate and maintain the combustion turbines and pollution control systems in accordance with the guidelines and procedures established by the manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions. [Applicant Request; Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

9. Automated Control System: In accordance with the manufacturer's recommendations, the permittee shall install, calibrate, tune, operate, and maintain a Speedtronic™ automated gas turbine control system for each unit. Each system shall be designed and operated to monitor and control the gas turbine combustion process and operating parameters including, but not limited to: air/fuel distribution and staging, turbine speed, load conditions, exhaust temperatures, heat input, and fully automated startup and shutdown. [Design; 62-212.400(BACT), F.A.C.]

10. DLN Combustion Technology: In accordance with the manufacturer's recommendations, the permittee shall install, tune, operate and maintain the General Electric dry low-NOx combustion system (DLN 2.6 or better) to control NOx emissions from each gas turbine. [Design; Rule 62-212.400(BACT), F.A.C.]

11. Tuning: Prior to the initial emissions performance tests for each gas turbine, the DLN 2.6 combustors and automated gas turbine control systems shall be tuned to optimize the reduction of CO, NOx, and VOC emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations to minimize these pollutant emissions. During tuning sessions, each combustion turbine shall be tuned for CO and NOx emissions performance of 9.0 ppmvd corrected to 15% oxygen or better. The permittee shall provide at least 5 days advance notice prior to any tuning session. [Design; Rule 62-212.400(BACT), F.A.C.]

12. Carbon Monoxide (CO)

a. *Gas Firing, Normal:* When firing natural gas under normal operating conditions, CO emissions from each combustion turbine shall not exceed 32.0

pounds per hour and 9.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load.

b. *Gas Firing With Power Augmentation:* When firing natural gas and injecting steam to provide power augmentation, CO emissions from each combustion turbine shall not exceed 47.0 pounds per hour and 15.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load or higher.

c. *Distillate Oil Firing:* When firing low sulfur distillate oil as a backup fuel, CO emissions from each combustion turbine shall not exceed 68.0 pounds per hour and 20.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load.

The permittee shall demonstrate compliance with these standards by conducting performance tests in accordance with EPA Method 10 and the requirements of this permit. [Rule 62-212.400(BACT), F.A.C.]

13. Nitrogen Oxides (NOx)

a. *Gas Firing, Normal*: When firing natural gas under normal operating conditions, NOx emissions from each combustion turbine shall not exceed 66.0 pounds per hour and 9.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load. In addition, NOx emissions shall not exceed 10.0 ppmvd corrected to 15% oxygen based on a 3-hour block average for data collected from the NOx continuous emissions monitor.

b. *Gas Firing With Power Augmentation*: When firing natural gas and injecting steam to provide power augmentation, NOx emissions from each combustion turbine shall not exceed 82.0 pounds per hour and 12.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load or higher. In addition, NOx emissions shall not exceed 12.0 ppmvd corrected to 15% oxygen based on a 3-hour block average for data collected from the NOx continuous emissions monitor.

c. *Gas Firing With Peaking*: When firing natural gas with high temperature peaking, NOx emissions from each combustion turbine shall not exceed 105.0 pounds per hour and 15.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at peak load. In addition, NOx emissions shall not exceed 15.0 ppmvd corrected to 15% oxygen based on a 3-hour rolling average for data collected from the NOx continuous emissions monitor.

d. *Distillate Oil Firing*: When firing low sulfur distillate oil as a backup fuel, NOx emissions from each combustion turbine shall not exceed 334.0 pounds per hour and 42.0 ppmvd corrected to 15% oxygen based on a 3-hour test average conducted at base load. In addition, NOx emissions shall not exceed 42.0 ppmvd corrected to 15% oxygen based on a 3-hour block average for data collected from the NOx continuous emissions monitor.

NOx emissions are defined as oxides of nitrogen measured as NO_2. The permittee shall demonstrate compliance by conducting performance tests and emissions monitoring in accordance with EPA Methods 7E, 20, and the requirements of this permit. [Rule 62-212.400(BACT), F.A.C.; 40 CFR 60.332]

14. Particulate Matter (PM/PM10) and Sulfur Dioxide (SO_2)

a. *Particulate Matter*: When firing natural gas under any method of operation, particulate matter emissions from each combustion turbine shall not exceed 9.0 pounds per hour based on a 3-hour test average conducted at base load. When firing distillate oil, particulate matter emissions from each combustion turbine shall not exceed 17.0 pounds per hour based on a 3-hour test average conducted at base load

b. *Fuel Specifications*. Emissions of PM, PM_{10}, and SO_2 shall be limited by the use of pipeline-quality natural gas containing no more than 1 grain per 100 standard cubic feet as the primary fuel and restricted use of No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight as a backup fuel. The fuel specifications are work practice standards ~~established as~~ which were determined by the Department under its PSD review to be BACT limits for PM, PM_{10}, and SO_2 emissions. The permittee shall demonstrate compliance with the fuel sulfur limits by maintaining the records specified in this permit. [Rule 62-212.400(BACT), F.A.C.; 40 CFR 60.333]

c. *VE Standard*. When firing natural gas or distillate oil, visible emissions from each combustion turbine shall not exceed 10% opacity, based on a 6-minute average. The visible emissions limits are work practice standards established as BACT limits for PM and PM10 emissions. The permittee shall demonstrate compliance with these standards by conducting tests in accordance with EPA Method 9 and the performance testing requirements of this permit. [Rule 62-212.400(BACT), F.A.C.]

15. Volatile Organic Compounds (VOC)

a. *Gas Firing With or Without Power Augmentation*: When firing natural gas, VOC emissions shall not exceed 3.0 pounds per hour and 1.5 ppmvw based on a 3-hour test average conducted at base load.

b. *Distillate Oil Firing*: When firing distillate oil, VOC emissions shall not exceed 7.5 pounds per hour and 3.5 ppmvw based on a 3-hour test average conducted at base load.

The VOC standards are established as PSD-synthetic minor limits. VOC emissions shall be measured and reported in terms of methane. The permittee shall demonstrate compliance with these standards by conducting tests in accordance with EPA Methods 25, 25A and the performance testing requirements of this permit. Optional testing in accordance with EPA Method 18 may be conducted to account for the actual methane fraction of the measured VOC emissions. [Design; Rule 62-4.070(3), F.A.C.]

16. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation, power augmentation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. All such emissions shall be included in the calculation of the 3-hour averages to demonstrate compliance with the continuous NOx emissions standard. [Rule 62-210.700(4), F.A.C.]

17. Excess Emissions Allowed: For each combustion turbine, excess NOx and visible emissions during startup, shutdown, and documented malfunction shall be allowed, providing:

a. Operators employ best operational practices to minimize the amount and duration of excess emissions.

b. Operation below 50% of base load shall not exceed 120 minutes during any calendar day.

c. During startup and shutdown, visible emissions excluding water vapor shall not exceed 20% opacity for up to ten, 6-minute observation periods during any calendar day. Data for each observation period shall be exclusive for the ten periods.

d. During all startups, shutdowns, and malfunctions, the NOx CEM shall monitor and record NOx emissions. For each calendar day, up to two 1-hour monitoring averages may be excluded from the continuous NOx compliance demonstration for each combustion turbine due to excess NOx emissions resulting from startup, shutdown, and documented malfunction. For excess NOx emissions due to malfunction, the permittee shall notify the ~~SE District Office~~ Southeast District Office within (1) working day of: the nature, extent, and duration of the excess emissions; the cause of the excess emissions; and the actions taken to correct the problem. In addition, the Department may request a written summary report of the incident.

e. If the permittee provides at least 5 days advance notice prior to tuning in accordance with the manufacturer's recommendations, up to three 1-hour monitoring averages may be excluded from the continuous NOx compliance demonstration for each gas turbine due to excess NOx emissions resulting from tuning. Note: It is expected that no more than two tuning sessions would occur each year. [Design; Rule 62-210.700(1) and (5); rule 62-4.130, F.A.C.]

18. Unconfined Particulate Emissions: During the construction period, unconfined particulate matter emissions shall be minimized by dust suppressing techniques such as covering and/or application of water or chemicals to the affected areas, as necessary. [Rule 62-296.320(4)(c), F.A.C.]

19. Circumvention: The permittee shall not circumvent the air pollution control equipment or allow the emission of air pollutants without this equipment operating properly. [Rule 62-210.650, F.A.C.]

20. Plant Operation - Problems: If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify the ~~SE District Office~~ Southeast District Office as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]

C. Emissions and Controls for Unit 8 - "4 on 1" Combined Cycle Gas Turbine [Emission Units 011, 012, 017 and 018]

1. NSPS Requirements: The Department determines that compliance with the ~~BACT~~ emissions performance and monitoring requirements included in these Conditions of Certification also assures compliance with the New Source Performance Standards for Subpart Da (duct burners) and Subpart GG (gas turbines) in 40 CFR 60.

~~For completeness, the applicable requirements of Subparts Da and GG are included in Appendices Da and GG of this permit.~~ [Rule 62-204.800(7), F.A.C.]

2. Gas Turbines: The permittee is authorized to install, tune, operate, and maintain four new General Electric Model PG7241FA gas turbine-electrical generator sets each with a generating capacity of 170 MW. Each gas turbine shall include the Speedtronic™ automated gas turbine control system and have dual-fuel capability. Ancillary equipment includes an inlet air filtration system, an evaporative inlet air-cooling system, and a bypass stack for simple cycle operation. The gas turbines will utilize the "hot nozzle" DLN combustors, which require natural gas to be preheated to approximately 290° F before combustion to increase overall unit efficiency. Gas-fired fuel heaters will preheat the natural gas during simple cycle operation and during startup to combined cycle operation. For full combined cycle operation, feedwater heat exchangers will preheat the natural gas. *{Permitting Note: Two existing simple cycle General Electric Model PG7241FA gas turbine-electrical generator sets, Units 8A and 8B (EU 011 and 012), will be incorporated into the "4-on-1" combined cycle Unit 8.}*

3. Gas Turbine NOx Controls

a. *DLN Combustion*: The permittee shall operate and maintain the General Electric DLN 2.6 combustion system (or better) to control NOx emissions from each gas turbine when firing natural gas. Prior to the initial emissions performance tests required for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve the simple cycle permitted levels for CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

b. Water Injection: The permittee shall install, operate, and maintain a water injection system to reduce NOx emissions from each gas turbine when firing distillate oil. Prior to the initial emissions performance tests required for each gas turbine, the water injection system shall be tuned to achieve the permitted levels for CO and NOx emissions. Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations. The automated control system shall be programmed to establish a water-to-fuel ratio designed to achieve the NOx emission standard for simple cycle oil firing on a 1-hour basis.

c. (SCR) System: The permittee shall install, tune, operate, and maintain a selective catalytic reduction (SCR) system to control NOx emissions from each gas turbine during combined cycle operation when firing either natural gas or distillate oil. The SCR system consists of an ammonia injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancillary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NOx emissions and ammonia slip.

[Design: Rule 62-212.400(BACT), F.A.C.]

4. HRSGs: The permittee is authorized to install, operate, and maintain four new heat recovery steam generators (HRSGs) with separate HRSG exhaust

stacks. Each HRSG shall be designed to recover heat energy from one of the four gas turbines (8A-8D) and deliver steam to the steam turbine electrical generator through a common manifold. Each HRSG may be equipped with supplemental gas-fired duct

burners shall be designed in accordance with the following specifications: 0.04 lb CO/MMBtu and 0.08 lb NOx/MMBtu.

5. Permitted Capacity-Combustion Turbines: The maximum heat input rate to each gas turbine is 1600 MMBtu per hour when firing natural gas and 1811 MMBtu per hour when firing distillate oil (based on a compressor inlet air temperature of 59° F, the lower heating value (LHV) of each fuel, and 100% load). Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Permitting and Compliance Authorities within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department. [Rule 62-210.200(PTE), F.A.C.]

6. Permitted Capacity - HRSG Duct Burners: The total heat input rate to the duct burners for each HRSG is 495 MMBtu per hour based on the lower heating value (LHV) of natural gas. Only natural gas shall be fired in the duct burners. [Rule 62-210.200(PTE), F.A.C.]

7. Methods of Operation: Subject to the restrictions and requirements of this ~~permit~~ certification, the gas turbines may operate under the following methods of operation.

a. *Hours of Operation*: Subject to the operational restrictions of this ~~permit~~ certification, the gas turbines may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified below.

b. *Authorized Fuels*: Each gas turbine shall fire natural gas as the primary fuel, which shall contain no more than 2.0 grains of sulfur per 100 standard cubic feet of natural gas. As a restricted alternate fuel, each gas turbine may fire No. 2 distillate oil (or a superior grade) containing no more than 0.05% sulfur by weight. Each gas turbine shall fire no more than 500 hours of distillate oil during any consecutive 12 months.

c. *Simple Cycle Operation*: Each gas turbine may operate individually in simple cycle mode to produce only direct, shaft-driven electrical power subject to the following operational restrictions.

(1) Each gas turbine shall operate in simple cycle mode for no more than 3390 hours during any consecutive 12 months.

(2) After demonstrating initial compliance in combined

cycle mode for no more than an average of 1000 hours per gas turbine during any consecutive 12 months.

d. *Combined Cycle Operation*: Each gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and deliver steam to the steam turbine-electrical generator to produce steam-generated electrical power as a four-on-one combined cycle unit subject to the restrictions of this permit. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.

e. *Inlet Fogging*: In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling system may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power. This method of operation is commonly referred to as "fogging" and may be used in either simple cycle or combined cycle modes.

f. *Peaking*: When firing natural gas, each gas turbine may operate in a high-temperature peaking mode to generate additional direct, shaft-driven electrical power to respond to peak demands. During any consecutive 12 months, each gas turbine shall operate while in the peaking mode for no more than 60 hours of simple cycle operation and no more than 400 hours of combined cycle operation.

g. *Power Augmentation*: When firing natural gas in either simple cycle or combined cycle modes, steam may be injected into each gas turbine to generate additional direct, shaft-driven electrical power to respond to peak demands. To qualify as "power augmentation", the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions. Prior to activating and after deactivating the power augmentation mode, the operator shall log the date, time, and new mode of operation. The gas turbines shall not operate simultaneously in peaking and power augmentation modes. Total combined operation of power augmentation and peaking modes shall not exceed 400 hours per unit during any consecutive 12 months.

h. *Combined Cycle Operation with Duct Firing*: When firing natural gas and operating in combined cycle mode, each HRSG system may fire natural gas in the duct burners to provide additional steam-generated electrical power. The total combined heat input rate to the duct burners (all four HRSGs) shall not exceed 5,702,400 MMBtu (LHV) during any consecutive 12 months.

[Application; Rules 62-210.200(PTE) and 62-212.400(BACT), F.A.C.]

8. Emissions Standards: Emissions from each gas turbine shall not exceed the following standards.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			Ppmvd @ 15% O_2	lb/hour	Ppmvd @ 15% O_2
CO[a]	Oil	Simple or Combined Cycle	14.4	64.7	15.0, 24-hr
	Gas	Simple Cycle	7.4	27.5	8.0, 24-hr
		Simple Cycle w/PA	12.0	45.0	12.0, 24-hr
		Combined Cycle, Normal	7.4	27.5	10.0, 24-hr
		Combined Cycle, All Modes	NA	NA	
Nox[b]	Oil	Simple Cycle	42.0	319.2	42.0, 3-hr
		Combined Cycle w/SCR	10.0	76.0	10.0, 24-hr
	Gas	Simple Cycle	9.0	58.7	9.0, 24-hr
		Simple Cycle w/PA	12.0	76.2	12.0, 24-hr
		Simple Cycle w/Peaking	15.0	95.3	15.0, 24-hr
		Combined Cycle w/SCR, Normal	2.5	16.3	2.5, 24-hr
		Combined Cycle w/SCR and DB	2.5	23.6	
		Combined Cycle w/SCR, All Modes	NA	NA	
PM/PM10[c]	Oil/Gas	Simple or Combined Cycle	Fuel Specifications		
		Simple or Combined Cycle	Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO_2[d]	Oil/Gas	Simple or Combined Cycle	Fuel Specifications		
VOC[e]	Oil	Simple or Combined Cycle	2.5	6.0	NA
	Gas	Simple or Normal Combined Cycle	1.3	2.8	NA
		Combined Cycle, w/DB and/or PA	4.0	10.5	NA
Ammonia[f]	Oil/Gas	Combined Cycle w/SCR	5	NA	NA

a. Compliance with the CO standards shall be demonstrated based on data

b. Compliance with the NOx standards shall be demonstrated based on data collected by the required CEMS. Compliance may also be determined by EPA Method 7E or 20. NOx mass emission rates are defined as oxides of nitrogen expressed as NO_2. Compliance with the 24-hour NOx CEMS standards during simple cycle operation shall be determined separately for each method of operation based on the hours of operation for each method. *{Permitting Note: A 24-hour compliance average may be based on as little as 1-hour of CEMS data or as much as 24-hours of CEMS data.}*

c. The fuel specifications established in Condition No. IV.C.0 of this section combined with the efficient combustion design and operation of each gas turbine ~~represents~~ were set using the Department's ~~the~~ Best Available Control

Technology (BACT) determination for PM/PM10 emissions in its PSD review. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

d. The fuel sulfur specifications in Condition No. IV.C.8 of this section effectively limit the potential emissions of SAM and SO2 from the gas turbines ~~and represent~~ were set using the Department's Best Available Control Technology (BACT) determination for these pollutants in its PSD review. Compliance with the fuel sulfur specifications shall be determined by the requirements in Condition No. IV.E.6. of this section.

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may be also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.

f. Subject to the requirements of Condition IV.D.5. of this section, each SCR system shall be designed and operated for an initial ammonia slip target of less than 5 ppmvd corrected to 15% oxygen based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTC-027. [Rule 62-212.400(BACT), F.A.C.]

9. Combined Cycle Operation With Dump Condenser: If the steam-electrical turbine generator is off line, the permittee is authorized to operate the gas turbine/HRSG systems by dumping steam to a condenser. When operating in this manner, each unit shall comply with the standards established for combined cycle operation with ammonia injection (SCR).

10. Duct Burners: The duct burners are also subject to the provisions of Subpart Da of the New Source Performance Standards in 40 CFR 60, which are summarized in Appendix Da. [Subpart Da, 40 CFR 60]

11. Existing Units 8A and 8B Simple Cycle Gas Turbines: Until commencement of the initial steam blows, the terms and conditions in IV.B. above shall apply to the two existing Unit 8 gas turbines, 8A and 8B (Emissions Unit Nos. 011 and 012), the two existing gas-fired fuel heaters (Emissions Unit 013) and the distillate oil storage tank (Emissions Unit 014). Thereafter, the conditions contained in IV.C. shall replace the conditions in IV.B. above. [Rule 62-4.070(3), F.A.C.]

12. Operating Procedures: ~~The Best Available Control Technology (BACT) determinations established by this permit rely on~~ In order to ensure that "good operating practices" will be used to reduce emissions~~. Therefore~~, all operators and supervisors shall be properly trained to operate and maintain the gas turbines, HRSGs, and pollution control systems in accordance with the guidelines and procedures

as well as methods of minimizing excess emissions. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

13. Excess Emissions Prohibited: Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data. [Rule 62-210.700(4), F.A.C.]

14. Alternate Visible Emissions Standard: Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

15. Excess Emissions Allowed: As specified in this condition, excess emissions resulting from startup, shutdown, and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the SE District Office by telephone, facsimile transmittal, or electronic mail. For each gas turbine/HRSG system, excess emissions resulting from startup, shutdown, or documented malfunctions occurrences shall in no case exceed two hours in any 24-hour period except for the following specific cases.

a. For cold startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed six hours in any 24-hour period. Cold startup of the steam turbine system shall be completed within twelve hours. A cold "startup of the steam turbine system" is defined as startup of the 4-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours.

b. For shutdown of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed three hours in any 24-hour period.

c. For cold startup of a gas turbine/HRSG system, excess emissions shall not exceed four hours in any 24-hour period. "Cold startup of a gas turbine/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.

d. For oil-to-gas fuel switching in simple cycle operation, excess emissions shall not exceed 1 hour in any 24-hour period.

Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, and documented malfunction of the gas turbines. [Design; Rules 62-212.400(BACT) and 62-210.700, F.A.C.]

16. Initial Steam Blows: Prior to completing the conversion from simple cycle to combined cycle operation, the permittee is authorized to operate each gas turbine at loads below 50% for the purpose of cleaning the HRSG piping system and piping connecting the HRSG to the steam turbine. Prior to conducting any steam blows, the permittee shall submit a proposed schedule to the SE District Office. On the first day of conducting steam blows, the permittee shall notify the ~~SE District Office~~ SE District Office that the process has begun. The permittee shall complete this process within 90 days of conducting the initial steam blow. For good cause, the permittee may request that the ~~SE District Office~~ SE District Office extend the steam blow period. During the steam blows, the following conditions apply:

a. The permittee shall take all precautions to minimize the extent and duration of excess emissions.

b. Each gas turbine shall fire only natural gas and each CEMS shall be on line and functioning properly.

c. CO and NOx emissions may exceed the ~~BACT~~ limits specified in this ~~permit~~ certification; however, NOx emissions shall not exceed the NSPS Subpart GG limit of 110 ppmvd corrected to 15% oxygen based on a 24-hour block average. If the NSPS standard is exceeded, the permittee shall notify the SE District Office within 24-hours of the incident.

Within 30 days of completing the initial steam blows, the permittee shall submit a report to the Bureau of Air Regulation and the SE District Office summarizing the daily emissions resulting from each steam blow.

17. DLN Tuning: CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the SE District Office with an advance notice that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail. [Design; Rule 62-4.070(3), F.A.C.]

D. Emissions Performance Testing (Phase II)

1. Test Methods: Any required tests shall be performed in accordance with the following reference methods:

Method	Description of Method and Comments
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source {Notes: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.}
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train.}
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography {Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.}
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
25A	Determination of Volatile Organic Concentrations

Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "http://www.epa.gov/ttn/emc/ctm.html". The other methods are described in Appendix A of 40 CFR 60, adopted by reference in Rule 62-204.800, F.A.C. No other methods may be used unless prior written approval is received from the Department. [Rules 62-204.800, F.A.C.; 40 CFR 60, Appendix A]

2. Initial Compliance Determinations: Each gas turbine shall be stack tested to demonstrate initial compliance with the emission standards for CO, NOx, VOC, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum production rate at which the unit will be operated for each unit configuration (i.e., simple cycle and combined cycle operation), but not later than 180 days after the initial startup of each unit configuration. Each unit shall be tested when firing natural gas and distillate oil. CEMS data collected during the required Relative Accuracy Test Assessments (RATA) may be used to demonstrate compliance with the initial 3-hour CO and NOx standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may also be used to demonstrate compliance with the CO and NOx mass emissions standards. CO and NOx emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. The Department may require the permittee to conduct additional tests after the replacement or major repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc. [Rule 62-297.310(7)(a)1., F.A.C.]

3. Continuous Compliance: The permittee shall demonstrate continuous compliance with the CO and NOx emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall submit a report to the SE District Office summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of particulate matter and volatile organic compounds. [Rule 62-212.400 (BACT), F.A.C.]

4. Annual Compliance Tests: During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions and ammonia slip. NOx emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period. *{Permitting Note: After initial compliance with the VOC standards is demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions.}* [Rules 62-212.400 (BACT) and 62-297.310(7)(a)4., F.A.C.]

5. Additional Ammonia Slip Testing: If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall:

a. Begin testing and reporting the ammonia slip for each subsequent calendar quarter;

b. Before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen, take corrective actions that result in lowering the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and

c. Test and demonstrate that the ammonia slip is no more than 5 ppmvd corrected to 15% oxygen within 15 days after completing the corrective actions.

Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is no more than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis. [Rules 62-4.070(3) and 62-297.310(7)(b), F.A.C.]

E. Continuous Monitoring and Reporting Requirements (Phase II)

1. CEM Systems: The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and NOx from the combined cycle gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NOx standard (and subject to the specified averaging period), the permittee shall notify the SE District Office.

a. *CO Monitors.* The CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the SE District Office. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.

b. *NOx Monitors*. Each NOx monitor shall be certified, operated, and maintained in accordance with the requirements of 40 CFR 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR 75. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60. In addition to the requirements of Appendix A of 40 CFR 75, the NOx monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.

c. *O_2 or CO_2 Monitors*. The oxygen (O2) or carbon dioxide (CO2) content of the flue gas shall be monitored at the location where CO and NOx are monitored to correct the measured emissions rates to 15% oxygen. If a CO2 monitor is installed, the oxygen content of the flue gas shall be calculated using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR 75.

d. *1-Hour Block Averages*. Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. An hour in which any oil is fired is attributed towards compliance with the permit standards for oil firing. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NOx as specified in this permit. For purposes of determining compliance with the CEMS emissions standards of this permit, missing (or excluded) data shall not be substituted. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

e. *3-hour Block Averages*: For oil firing during simple cycle operation, the 3-hour block average shall be calculated from three consecutive hourly average emission rate values. For purposes of determining compliance with the CEMS emission standards of this permit, missing (or excluded) data shall not be substituted. Instead, the 3-hour block average shall be determined using the remaining hourly data in the 3-hour block. [Rule 62-212.400(BACT), F.A.C.]

f. *24-hour Block Averages*: A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, missing (or excluded) data shall not be substituted. Instead, the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block. [Rule 62-212.400(BACT), F.A.C.]

g. *Data Exclusion.* Each CEMS shall monitor and record emissions during all operations including episodes of startup, shutdown, malfunction, fuel switches, DLN tuning, and steam blows. CEMS emissions data recorded during some of these episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Condition Nos. 16 and 18 of this section. All periods of data excluded shall be consecutive for each such episode. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

h. *Availability.* Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The quarterly permit excess emissions report shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this certification, except as otherwise authorized by the Department's SE District Office.
{ [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

2. Water Injection Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain a monitoring system to continuously measure and record the water-to-fuel ratio when firing distillate oil. The permittee shall document the water-to-fuel ratio required to meet permitted emissions levels over the range of load conditions allowed by this permit. The NOx CEMS is used to demonstrate compliance with the NOx emissions standards.

water-to-fuel ratio that is consistent with the documented flow rate for the gas turbine load condition. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

3. Ammonia Monitoring Requirements: In accordance with the manufacturer's specifications, the permittee shall install, calibrate, operate and maintain an ammonia flow meter to measure and record the ammonia injection rate to the SCR system. The permittee shall document the general range of ammonia flow rates required to meet permitted emissions levels over the range of load conditions allowed by this permit by comparing NOx emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NOx monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the combustion turbine load condition. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

4. Monitoring of Capacity: The permittee shall monitor and record the operating rate of each gas turbine and HRSG duct burner system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

5. Monthly Operations Summary: By the fifth calendar day of each month, the permittee shall record the following for each fuel in a written or electronic log for each gas turbine for the previous month of operation: fuel consumption, hours of operation, hours of power augmentation, hours of peaking, hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-212.400(BACT), F.A.C.]

6. Fuel Sulfur Records: The permittee shall demonstrate compliance with the fuel sulfur limits specified in this certification by maintaining the following records of the sulfur contents.

a. Compliance with the fuel sulfur limit for natural gas shall be demonstrated by keeping reports obtained from the vendor indicating the average sulfur content of the natural gas being supplied from the pipeline for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 or more recent versions.

b. Compliance with the distillate oil sulfur limit shall be demonstrated by taking a sample, analyzing the sample for fuel sulfur, and reporting the results to each SE District Office before initial startup. Sampling the fuel oil sulfur content shall be conducted in accordance with ASTM D4057-88, Standard Practice for Manual Sampling of Petroleum and Petroleum Products, and one of the following test methods for sulfur in petroleum products: ASTM D129-91, ASTM D1552-90, ASTM D2622-94, or ASTM D4294-90. More recent versions of these methods may be used. For each subsequent fuel delivery, the permittee shall maintain a permanent file of the certified fuel sulfur analysis from the fuel vendor. At the request of the SE District Office, the permittee shall perform additional sampling and analysis for the fuel sulfur content.

The above methods shall be used to determine the fuel sulfur content in conjunction with the provisions of 40 CFR 75 Appendix D. [Rules 62-4.070(3) and 62-4.160(15), F.A.C.]

7. Malfunction Notification: Within one working day of a malfunction that causes emissions in excess of a standard, subject to the specified averaging periods), the permittee shall notify the SE District Office. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the probable

[illegible]

the ~~SE District Office~~ SE District Office, the permittee shall submit written quarterly reports summarizing the malfunctions. [Rule 62-210.700, F.A.C.]

8. Semiannual NSPS Excess Emissions Report: In accordance with 40 CFR 60.7(d), the permittee shall submit a report to the SE District Office summarizing any emissions in excess of the NSPS standards within 30 days following the end of each calendar quarter. For purposes of reporting emissions in excess of NSPS Subpart GG, excess emissions from the gas turbine are defined as: any CEMS hourly average value exceeding the NSPS NOx emission standard identified in Appendix GG; and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard identified in Appendix GG. For purposes of reporting emissions in excess of NSPS Subpart Da, excess emissions from duct firing are defined as: NOx or PM emissions in excess of the NSPS standards except during periods of startup, shutdown, or malfunction; and SO2 emissions in excess of the NSPS standards except during startup or shutdown. [40 CFR 60.7]

9. Quarterly Permit Excess Emission Report: Within 30 days following the end of each quarter, the permittee shall submit a report to the SE District Office summarizing periods of excess CO and NOx emissions. Such information shall also be summarized for simple/combined cycle startups, simple/combined cycle shutdowns, malfunctions, and major tuning sessions. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter. [Rules 62-4.130, 62-204.800, 62-210.700(6), F.A.C.; and 40 CFR 60.7]

F. Four Gas-Fired Fuel Heaters [Emission Unit IU 013]

1. NSPS Subpart Dc Applicability: The gas-fired fuel heaters are subject to Subpart Dc of the New Source Performance Standards in 40 CFR 60 as well as the General Provisions of Subpart A. This regulation applies to each steam-generating unit with a heat input rate of less than 100 MMBtu per hour, but more than 10 MMBtu per hour. Steam generating unit is defined as, "... a device that combusts any fuel and produces steam or heats water or any other heat transfer medium." [40 CFR 60.40c; 40 CFR 60.41c; Rule 62-204.800(7)(b), F.A.C.]

2. Equipment: The permittee is authorized to install, operate, and maintain four fuel heaters fired exclusively with natural gas at a maximum heat input rate of 24 MMBtu per hour. The fuel heaters will be designed to preheat the natural gas during simple cycle operation and during startup to combined cycle operation. For full combined cycle operation, feedwater heat exchangers will preheat the natural gas. *{Permitting Note: In accordance with Air Permit No. PSD-FL-286, construction of two gas-fired fuel heaters has been completed.}* [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

3. Hours of Operation: The hours of operation for the gas-fired fuel heaters are not restricted (8760 hours per year). [Applicant Request; Rule 62-210.200(PTE), F.A.C.]

4. Good Combustion: If visible emissions are greater than 5% opacity, the permittee shall investigate the cause, take appropriate corrective actions, and document the incident. This condition does not impose any initial or periodic testing. [Rules 62-4.070(3) and 62-210.700(4), F.A.C.; 40 CFR 60, Appendix A]

5. Subpart Dc Notification, Reporting and Record Keeping Requirements: The gas-fired fuel heaters are subject to the following notification, reporting and record keeping requirements of 40 CFR 60.48c.

a. The owner or operator of each affected facility shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup, as provided by §60.7 of this part. This notification shall include:

1) The design heat input capacity of the affected facility and identification of fuels to be combusted in the affected facility.

2) The annual capacity factor at which the owner or operator anticipates operating the affected facility based on all fuels fired and based on each individual fuel fired.

b. The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day. All records required under this section shall be maintained by the owner or operator of the affected facility for a period of two years following the date of such record. The reporting period for the reports required under this subpart is each six-month period. All reports shall be submitted to the SE District Office and shall be postmarked by the 30th day following the end of the reporting period. [40 CFR 60.48c (a), (g), (i), and (j)]

G. Cooling Tower [Emission Unit 020]

1. Cooling Tower: The permittee is authorized to install one new 18-cell mechanical draft cooling tower with the following design characteristics: a circulating water flow rate of 310,000 gpm; design hot/cold water temperatures of 104° F/90° F; a design air flow rate of 1,386,055 per cell; a liquid-to-gas air flow ratio of 1.4; and drift eliminators with a drift rate of no more than 0.001 percent. The permittee shall submit the final design details within 60 days of selecting the vendor.

2. Drift Rate: Within 60 days of commencing operation, the permittee shall certify that the cooling tower was constructed to achieve the specified drift rate of

Material	TPY
Coal	6,935,000
Slag and Fly Slag	1,700,000
Sulfur	310,000
Spent Solvent	80
Spent Claus Catalyst	80
Demineralizer Resin Beds	70

3. The maximum particulate matter emissions from the material handling and storage activities shall not exceed 1,566 tons per year. Emissions from these sources shall be controlled using the following measures:

Fugitive Dust Source	Control Technology
Coal Unloading	Enclosed with Dry Collection System
Limestone Unloading	Wet Suppression System[1]
Conveyors and Transfer Points (Coal, Limestone, Slag)	Transfer Points Enclosed with Dry Collection System Conveyors Covered.
Coal Storage (Inactive)	Crusting Agent Application (60% Control)
Coal Storage (Active)	Surfactant Application[1]
Coal Storage (Active) and Reclaiming	Surfactant Application
Limestone Storage	Crusting Agent Application[1]
Slag Transport to By Product Storage Area	Paved Road, Covered Conveyor (95% Control)
Slag By Product Storage Area (Inactive)	Topsoil Covered and Seeded (100% Control)
Slag By Product Storage Area (Active)	Compaction, Temporary Cover (Natural or Synthetic)
Sulfur Storage	Stored in molten state in tanks or in crystalline slab arrangement.

1 Undefined rate of fugitive dust control.

The emissions from the above listed sources where baghouses are used are subject to the particulate emission limitation requirements of 0.03 gr/dscf. However, DEP will not require particulate tests in accordance with EPA Method 5 unless the VE limit of 5% opacity is exceeded for a given source, or unless DEP, based on other information, has reason to believe the particulate emission limits are being violated.

4. Visible Emissions (VE) shall not exceed 5% opacity from any source in the material handling and treatment area, in accordance with Chapter 62-210, F.A.C.

5. Initial and annual Visible Emission compliance tests for all the emission points in the material handling and treatment area, including, but not limited to, the sources specified in this permit, shall be conducted in accordance with the November 2, 1989, version of 40 CFR 60, using EPA Method 9 or DEP approved method.

6. Compliance test reports shall be submitted to DEP within 45 days of test completion in accordance with Chapter 62-297.310(8), F.A.C.

7. Any changes in the method of operation, raw materials processed, equipment, or operating hours or any other changes pursuant to Rule 17-2.100, F.A.C., defining modification, shall be submitted for approval to DEP's Bureau of Air Regulation (BAR).

~~III~~ V. SURFACE WATER DISCHARGES

Discharges into surface waters of the state during construction and operation of the project shall be in accordance with applicable provisions of 62-4, 62-160, 62-302, 62-601, 62-650, and 62-660, F.A.C., DEP Permit No. FL0030988-002-IW1S, and the following Conditions of Certification:

A. Plant Effluents and Receiving Body of Water.

For discharges made from the Martin Power Plant ~~CG/CC Project~~ the following conditions shall apply:

1. Receiving Body of Water (RBW). The receiving body of water has been determined by DEP to be (a) those waters of the discharge canal leading to the St. Lucie Canal which are considered to be waters of the state within the definition of Chapter 403, F .S., and (b) those water of the L-65 canal receiving cooling pond seepage from culverts 003a through 003e.

2. Points of Discharge (PODs). The points of discharge have been determine by DEP to be where the effluent physically enters the waters of the state in the discharge canal and the L-65 canal at the Outfall Serial Numbers (OSNs) 001, 002, and 003.

3. Thermal Limits. Heated water discharged at OSN 001 shall not be more than 5° F higher than the ambient (natural) temperature in the St. Lucie canal and shall not exceed 92° F. At all times under all conditions of stream flow the discharge temperature shall be controlled so that at least two thirds (2/3) of the width of the discharge canal's surface remains at ambient (natural) temperature. Further, no more than one fourth (1/4) of the cross section of the discharge canal at a traverse

FLORIDA POWER & LIGHT COMPANY

MANATEE UNIT 3
POWER PLANT SITING APPLICATION
PA-22-44

FINAL ORDER OF CERTIFICATION AND
EXCERPTS FROM CONDITIONS OF CERTIFICATION –
SECTION XXIII - AIR

RRL-2
DOCKET NO. 040007-EI
FPL WITNESS: R. R. LABAUVE
EXHIBIT ______________
PAGES 1-21

STATE OF FLORIDA
SITING BOARD

IN RE:	FLORIDA POWER & LIGHT COMPANY MANATEE UNIT 3 POWER PLANT SITING APPLICATION NO. PA 02-44.	OGC CASE NO.:	02-0317
		DOAH CASE NO.:	02-0937EPP

FINAL ORDER OF CERTIFICATION

On February 19, 2003, an administrative law judge with the Division of Administrative Hearings (DOAH) submitted his Recommended Order in this electrical power plant certification proceeding. Copies of the Recommended Order were served upon Mansota-88, Inc., and upon counsel for Florida Power & Light Company ("FPL"), Florida Department of Environmental Protection ("DEP"), Manatee County, Southwest Florida Water Management District ("SWFWMD"), Tampa Bay Regional Planning Council ("TBRPC"), and other designated agencies. A copy of the Recommended Order is attached as Exhibit A. The matter is now before the Governor and Cabinet, sitting as the "Siting Board," for final action under the Florida Electrical Power Plant Siting Act ("PPSA"). See §§ 403.501-403.518, Florida Statutes.

BACKGROUND

On February 22, 2002, FPL filed a PPSA application for certification by the Siting Board of a proposed new electrical generating unit to be located at FPL's existing Manatee Plant site. The Manatee Plant site encompasses about 9,500 acres of property situated in a primarily agricultural and rural area of Manatee County, Florida. There are two existing electrical generating units at the Manatee Plant (Units 1 and 2). FPL proposes to construct and operate a new Unit 3 and related structures to be located on a 73-acre parcel within the existing Manatee Plant site (the "Project").

The proposed Unit 3 will be a 1100-megawatt combined-cycle electrical generating unit fueled solely by natural gas. The Project will consist of four combustion turbines, four heat recovery steam generators, one for each combustion turbine, and a new steam turbine. The Project will also involve the expansion of the existing on-site electrical system substation and the construction of several new appurtenant structures. FPL expects to commence construction of the Project in June of 2003. The planned in-service date for Unit 3 is June of 2005.

DOAH PROCEEDINGS

After FPL's application was deemed to be complete, DEP forwarded the matter to DOAH and Administrative Law Judge Charles A. Stampelos ("ALJ") was assigned to the case. The ALJ held a land use hearing on the Project in August of 2002 and entered a subsequent Recommended Order concluding that the site of the Project is consistent and in compliance with the land use plans and zoning ordinances of Manatee County. By order dated December 9, 2002, the Siting Board adopted the ALJ's Recommended Order on land use and determined that the site of the Project is consistent and in compliance with the land use plans and zoning ordinances of Manatee County. On December 10, 2002, the Florida Public Service Commission issued its Final Order determining the need for Manatee Unit 3, pursuant to § 403.519, Florida Statutes.

On December 18, 2002, DEP issued its written Staff Analysis Report (Report) concerning the Project. The Report contained reports from other state, regional, and local agencies. The Report also compiled a set of proposed Conditions of Certification for Manatee Unit 3 proposed by DEP and the other agencies that reviewed the Project. On January 21, 2003, a joint prehearing stipulation was filed with DOAH indicating that no party to this proceeding objected to certification of the Project. During the subsequent certification hearing, DEP submitted a revised Staff Analysis Report (DEP Exhibit 2) updating and correcting various matters in the earlier version of its analysis, and revising the proposed Conditions of Certification.

The ALJ conducted a certification hearing in Manatee County on January 27, 2003, as required by § 403.508(3), Florida Statutes. Evidence was presented at this hearing by various parties, including FPL, DEP, and SWFWMD. Members of the general public were also allowed to offer testimony at the conclusion of the certification hearing. On February 19, 2003, the ALJ entered his Recommended Order on site certification in this case. The ALJ concluded that the competent, substantial evidence at the certification hearing "demonstrates that FPL has met its burden of proof to demonstrate that Manatee Unit 3 meets the criteria for certification under the PPSA." The ALJ recommended that "the Siting Board grant full and final certification" to FPL for the Manatee Unit 3 Project as described in FPL's application and the evidence presented at the certification hearing, and subject to the Conditions of Certification contained in DEP Exhibit 2 appended to the Recommended Order.

CONCLUSION

The record in this case is devoid of objections by any governmental agencies to site certification of the Manatee Unit 3 Project. Furthermore, no Exceptions were filed in this case by any party challenging any of the factual findings, legal conclusions, or recommendation set forth in the ALJ's Recommended Order on site certification. Based on a review of the record and the governing law, the Siting Board concludes that the Manatee Unit 3 Project complies with the certification requirements of the PPSA and that site certification of the Project will fully balance the increasing demand for electrical power plant location and operation in this State with the broad interests of the public that are protected by the PPSA.

It is therefore ORDERED that:

A. The following clerical corrections are made to the Conditions of Certification for Manatee Unit 3 appended to the Recommended Order:[1]

1. The second unlabeled paragraph on page 15 is properly labeled as footnote "b." and the remaining four paragraphs on page 15 are relabeled as footnotes c. through f.
2. The table on page 27 is corrected by adding the "≤" (less than or equal to) sign immediately prior to the "Qriv" symbol for each of the six flow conditions of the Little Manatee River, as shown in the left hand column of the table.

B. The Recommended Order is otherwise adopted and incorporated by reference herein.

C. Certification of the location, construction, and continued operation of the Manatee Unit 3 Project as described in FPL's site certification application and by the evidence presented at the certification hearing is APPROVED, subject to the Conditions of Certification contained in DEP Exhibit 2 appended to the Recommended Order, as corrected in paragraph A above.

D. Authority to assure and enforce compliance by FPL and its agents with all of the Conditions of Certification imposed by this Final Order is hereby delegated to DEP, except that any proposed modification to burn a fuel other than natural gas shall be reviewed by the Siting Board.

Any party to this proceeding has the right to seek judicial review of the Final Order pursuant to Section 120.68, Florida Statutes, by the filing of a Notice of Appeal pursuant to Rule 9.110, Florida Rules of Appellate Procedure, with the clerk of the Department in the Office of General Counsel, 3900 Commonwealth Boulevard, M.S. 35, Tallahassee, Florida 32399-3000; and by filing a copy of the Notice of Appeal accompanied by the applicable filing fees with the

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[1] An unopposed "Notice of Clerical Errors" was filed with the DEP Agency Clerk on behalf of FPL, DEP, and SWFWMD. These clerical corrections to portions of pages 15 and 27 of the Manatee Unit 3 Conditions of Certification are based on this Notice of Clerical Errors.

appropriate District Court of Appeal. The Notice of Appeal must be filed within 30 days from the date this Final Order is filed with the clerk of the Department.

DONE AND ORDERED this 11 day of April, 2003, in Tallahassee, Florida, pursuant to a vote of the Governor and Cabinet, sitting as the Siting Board, at a duly noticed and constituted Cabinet meeting held on April 8, 2003.

THE GOVERNOR AND CABINET
SITTING AS THE SITING BOARD

THE HONORABLE JEB BUSH
GOVERNOR

FILED ON THIS DATE PURSUANT TO § 120.52, FLORIDA STATUTES, WITH THE DESIGNATED DEPARTMENT CLERK, RECEIPT OF WHICH IS HEREBY ACKNOWLEDGED.

CLERK 4/14/03
DATE

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a copy of the foregoing Final Order on Certification has been sent by United States Postal Service to:

Ross Stafford Burnaman, Esquire
James V. Antista, Esquire
Fish and Wildlife Conservation Commission
620 South Meridian Street
Tallahassee, FL 32399-1600

Roger Tucker, Esquire
Tampa Bay Regional Planning Council
9455 Koger Boulevard, Suite 219
St. Petersburg, FL 33702-2491

Peter C. Cunningham, Esquire
Douglas S. Roberts, Esquire
Hopping Green & Sams
Post Office Box 6526
Tallahassee, FL 32314-6526

Martha A. Moore, Esquire
Southwest Florida Water Management District
2379 Broad Street
Brooksville, FL 34604-6899

ManaSota-88, Inc.
c/o Glenn Compton, Chairman
419 Rubens Drive
Nokomis, Florida 34275

Ann Cole, Clerk and
Charles A. Stampelos, Administrative Law Judge
Division of Administrative Hearings
The DeSoto Building
1230 Apalachee Parkway
Tallahassee, FL 32399-1550

Colin Roopnarine, Esquire
Assistant General Counsel
Department of Community Affairs
2555 Shumard Oak Boulevard
Tallahassee, FL 32399-2100

Jeffrey N. Steinsnyder, Esquire
Manatee County Attorney's Office
Post Office Box 1000
Bradenton, FL 34206

Sheauching Yu, Esquire
Department of Transportation
Haydon Burns Building, MS 58
605 Suwannee Street
Tallahassee, FL 32399-0450

Robert V. Elias, Esquire
Martha Carter Brown, Esquire
Florida Public Service Commission
Gerald Gunter Building
2450 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

and by hand delivery to:

Scott A. Goorland, Esquire
Department of Environmental Protection
3900 Commonwealth Blvd., M.S. 35
Tallahassee, FL 32399-3000

this 14th day of April, 2003.

STATE OF FLORIDA DEPARTMENT
OF ENVIRONMENTAL PROTECTION

/for

J. TERRELL WILLIAMS
Assistant General Counsel
3900 Commonwealth Blvd., M.S. 35
Tallahassee, FL 32399-3000
Telephone 850/245-2242

CONDITIONS OF CERTIFICATION: PA 02-44

FLORIDA POWER & LIGHT CORPORATION
MANATEE ELECTRIC POWER GENERATION FACILITY UNIT 3

I. CERTIFICATION CONTROL

A. Under the control of these Conditions of Certification the Florida Power & Light Company (FPL) will operate an 1100 MW (nominal) facility consisting of four 170 MW combustion turbines, four heat recovery steam generators with duct burners, a 420 MW steam turbine and generator, and ancillary equipment. The facility is known as the Manatee Unit 3 and is located on a 72.8 acre site which is located within the existing 9,500 acre FPL Manatee site, Section 18, Township 33S, Range 20E, Manatee County, Florida.

B. These Conditions of Certification, unless specifically amended or modified, are binding upon the Licensee and shall apply to the construction and operation of the certified facility. If a conflict should occur between the design criteria of this project and the Conditions of Certification, the Conditions shall prevail unless amended or modified. In any conflict between any of these Conditions of Certification, the more specific condition governs.

II. APPLICABLE RULES

The construction and operation of the certified facility shall be in accordance with all applicable provisions of Florida Statutes and Florida Administrative Code, including, but not limited to, the following regulations: Chapter 403, Florida Statutes (F.S.), and Chapters 40D-1, 40D-4, 40D-40, 40D-45, 62-4, 62-17, 62-256, 62-296, 62-297, 62-301, 62-302, 62-531, 62-532, 62-550, 62-555, 62-560, 62-600, 62-601, 62-604, 62-610, 62-620, 62-621, 62-650, 62-699, 62-660, 62-701, 62-762, 62-767, 62-769, and 62-770, Florida Administrative Code (F.A.C.), or their successors as they are renumbered.

III. DEFINITIONS

Unless otherwise indicated herein, the meaning of terms used herein shall be governed by the definitions contained in Chapters 373 and 403, Florida Statutes, and any regulation adopted pursuant thereto. In the event of any dispute over the meaning of a term used in these conditions which is not defined in such statutes or regulations, such dispute shall be resolved by reference to the most relevant definitions contained in any other state or federal statute or regulation or, in the alternative by the use of the commonly accepted meaning as determined by the Department. In addition, the following shall apply:

A. "DCA" shall mean the Florida Department of Community Affairs.

the applicable Conditions of Certification. If a violation of standards, harmful effects or irreversible environmental damage not anticipated by the application or the evidence presented at the certification hearing are detected during construction, the Licensee shall notify the DEP District Office as required by Condition VII, Compliance.

D. Reporting

Notice of commencement of construction shall be submitted to the Siting Coordination Office and the DEP Southwest District Office within fifteen (15) days after initiation. Starting three (3) months after construction commences, a quarterly construction status report shall be submitted to the DEP Southwest District Office. The report shall be a short narrative describing the progress of construction.

XXIII. AIR

A. General

1. The construction and operation of the Manatee Unit 3 project shall be in accordance with all applicable provisions of any Prevention of Significant Deterioration (PSD) Permit and/or Title V permit issued for Manatee Unit 3 and of any updates or modifications thereto, and of Chapters 62-210 through 62-297, F.A.C

2. All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the

Air Quality Division
DEP Southwest District Office
3804 Coconut Palm Dr.
Tampa, Florida 33619-8218.

Copies of all such documents shall also be submitted to

Air Section
Manatee County Environmental Management Department
202 Sixth Avenue East
Bradenton, Florida 34208.

B. Equipment

The permittee is authorized to install, tune, operate, and maintain four new General Electric Model PG7241FA gas turbine-electrical generator sets each with a nominal capacity of 170 MW (EU 006, 007, 008 and 009). Each gas turbine shall include the Speedtronic™ automated gas turbine control system . Ancillary equipment includes an inlet air filtration system, an evaporative inlet air cooling system, and a bypass stack for simple cycle operation The gas turbines will utilize the "hot nozzle" DLN combustors, which require natural gas to be preheated to approximately 290° F before combustion to increase overall unit efficiency. Gas-fired fuel heaters (EU 010) will preheat the natural gas during simple cycle operation and during startup to combined cycle operation. For full combined cycle operation, feedwater heat exchangers will preheat the natural gas.

2. Gas Turbine Controls

a. The permittee shall tune, maintain and operate the General Electric DLN-2.6 combustion system to control NO_X emissions from each turbine. Prior to the initial emissions performance tests for each gas turbine, the DLN combustors and automated gas turbine control system shall be tuned to achieve the simple cycle permitted level for CO and NOx . Thereafter, each system shall be maintained and tuned in accordance with the manufacturer's recommendations.

b. The permittee shall install, tune, maintain and operate a SCR system to control NOx emissions from each turbine during a combined cycle operation mode. The SCR system consists of an ammonia injection grid, catalyst, ammonia storage, monitoring and control system, electrical, piping and other ancilliary equipment. The SCR system shall be designed, constructed and operated to achieve the permitted levels for NOx emissions and ammonia slip. *{Note: In accordance with 40 CFR 60.130, the storage of ammonia shall comply with all applicable requirements of the Chemical Accident Prevention Provisions of 40 CFR 68}*

The permittee is authorized to install, operate, and maintain four new heat recovery steam generators (HRSGs). Each HRSG shall be designed to recover heat energy from one of the four gas turbines (3A-3D) and deliver steam to the steam turbine electrical generator through a common manifold. Each HRSG may be equipped with supplemental gas-fired duct burners having a maximum heat input rate of 495 MMBtu per hour (LHV). *{Note: The four HRSGs deliver steam to a single steam turbine-electrical generator with a nominal capacity of 470 MW.}*

C. The maximum heat input rate to each gas turbine is 1600 MMBtu/hr (normal conditions) based on a compressor inlet air temperature of 59° F, the lower heating value (LHV) of natural gas, and 100% load. Heat input rates will vary depending upon gas turbine characteristics, ambient conditions, alternate methods of operation, and evaporative cooling. The permittee shall provide manufacturer's performance curves (or equations) that correct for site conditions to the Air Quality Division, DEP Southwest District Office within 45 days of completing the initial compliance testing. Operating data may be adjusted for the appropriate site conditions in accordance with the performance curves and/or equations on file with the Department.

D. The total maximum heat input rate to the duct burners for each HRSG is 495 MMBTU/hr based on the lower heating value (LHV) of the natural gas.

E. Subject to the restrictions and requirements of this certification, the gas turbines may operate under the following methods of operation.

1. Subject to the operational restrictions of this certification, the gas turbines may operate throughout the year (8760 hours per year). Restrictions on individual methods of operation are specified below.

2. Each gas turbine shall fire natural gas as the primary fuel, which shall contain on average no more than 2 grains of sulfur per 100 standard cubic feet of natural gas.

3. Each gas turbine/HRSG system may operate to produce direct, shaft-driven electrical power and steam-generated electrical power from the steam turbine-electrical generator as a four-on-one combined cycle unit subject to the restrictions of this certification. In accordance with the specifications of the SCR and HRSG manufacturers, the SCR system shall be on line and functioning properly during combined cycle operation or when the HRSG is producing steam.

4. When firing natural gas and operating in combined cycle mode, each gas turbine/HRSG system may fire natural gas in the duct burners to provide additional steam-generated electrical power. The total combined heat input to the duct burners (all four HRSGs) shall not exceed 5,702,400 MMBtu (LHV) during any consecutive 12 months.

5. Each gas turbine may operate individually in simple cycle mode to produce only direct, shaft-driven electrical power subject to the following operational restrictions.

a. Prior to demonstrating compliance in combined cycle mode, each gas turbine shall operate in simple cycle mode for no more than 3390 hours during any consecutive 12 months.

b. After demonstrating initial compliance in combined cycle mode, the combined group of four gas turbines shall operate in simple cycle mode for no more than an average of 1000 hours per unit during any consecutive 12 months.

6. In accordance with the manufacturer's recommendations and appropriate ambient conditions, the evaporative cooling system may be operated to reduce the compressor inlet air temperature and provide additional direct, shaft-driven electrical power. This method of operation is commonly referred to as "fogging" and may be used in either simple cycle or combined cycle modes.

7. When firing natural gas in either simple cycle or combined cycle modes, steam may be injected into each gas turbine to generate additional direct, shaft-driven electrical power to respond to peak demands. To qualify as "power augmentation", the combustion turbine must operate at a load of 95% or greater than that of the manufacturer's maximum base load rate adjusted for the compressor inlet air conditions. Prior to activating and after deactivating the power augmentation mode, the operator shall

log the date, time, and new mode of operation. Each gas turbine shall operate in this power augmentation mode no more than 400 hours per unit during any consecutive 12 months.

8. When firing natural gas, each gas turbine may operate in a high-temperature peaking mode to generate additional direct, shaft-driven electrical power to respond to peak demands. During any consecutive 12 months, each gas turbine shall operate in this peaking mode for no more than 60 hours of simple cycle operation and no more than 400 hours of combined cycle operation. The gas turbines shall not operate simultaneously in peaking and power augmentation modes. In addition, total combined operation of power augmentation and peaking modes shall not exceed 400 hours per unit during any consecutive 12 months.

F. Emissions from each gas turbine shall not exceed the following standards.

Pollutant	Fuel	Method of Operation	Stack Test, 3-Run Average		CEMS Block Average
			ppmvd @ 15% O2	lb/hr	ppmvd @ 15% O2
CO[a]	Gas	Simple Cycle	7.4	27.5	8.0, 24-hr
		Simple Cycle w/PA	12.0	45.0	12.0, 24-hr
		Combined Cycle, Normal Operation	7.4	27.5	10.0, 24-hr
		All Modes			
NOx[b]	Gas	Simple Cycle	9.0	58.7	9.0, 24-hr
		Simple Cycle w/PA	12.0	76.2	12.0, 24-hr
		Simple Cycle w/PK	15.0	95.3	15.0, 24-hr
		Combined Cycle w/SCR	2.5	16.3	2.5, 24-hr
		Combined Cycle w/SCR and DB	2.5	23.6	2.5, 24-hr
		Combined Cycle w/SCR, All Modes	N/A	N/A	2.5, 24-hr
PM/PM10[c]	Gas	Simple or Combined Cycle	Fuel Specifications		
		Simple or Combined Cycle	Visible emissions shall not exceed 10% opacity for each 6-minute block average.		
SAM/SO2[d]	Gas	Simple or Combined Cycle	Fuel Specifications		
VOC[e]	Gas	Simple or Normal Combined Cycle	1.3	2.8	NA
VOC[e]	Gas	Combined Cycle, w/DB and/or PA	4.0	10.5	NA

Ammonia[f]	Gas	Combined Cycle w/SCR	5	NA	NA

Notes:

a. Compliance with the CO standards shall be demonstrated based on data collected by the required CEMS. Compliance may also be determined by EPA Method 10. Compliance with the 24-hr CO CEMS standard shall be determined separately for each mode of operation based on the hours of operation in each mode. {*Note*: 24-hr compliance average may be based on as little as 1-hr of data or as much as 24-hr of CEMS data}.

b. Compliance with the NO_X standards shall be demonstrated based on data collected by the required CEMS. Compliance may also be determined by EPA Method 7E or 20. NO_X mass emission rates are defined as oxides of nitrogen expressed as NO2. Compliance with the 24-hr NO_X CEMS standards during simple cycle operation shall be determined separately for each method of operation based on the hours of operation for each method.

{Note: A 24-hr compliance average may be based on as little as 1-hr of CEMS data or as much as 24-hr of CEMS data .}

c. In its review for the prevention of Significant Deterioration permit for this facility, the Department determined that the fuel specifications combined with the efficient combustion design and operation of each gas turbine represents the Best Available Control Technology (BACT) determination for PM/PM10 emissions. Note, however, that the specifications and emissions limitations in this certification do not establish BACT. Compliance with the fuel specifications, CO standards, and visible emissions standards shall serve as indicators of good combustion. Compliance with the fuel specifications shall be demonstrated by keeping records of the fuel sulfur content. Compliance with the visible emissions standard shall be demonstrated by conducting tests in accordance with EPA Method 9.

{Note: PM10 emissions for gas firing are estimated at 9 lb/hour for simple cycle operation, 11 lb/hour for combined cycle operation, and 17 lb/hour for combined cycle operation with duct burning.}

d. In its review for the prevention of Significant Deterioration permit for this facility, the Department determined that the fuel sulfur specifications effectively limit the potential emissions of SAM and SO2 from the gas turbines and represent the Best Available Control Technology (BACT) determination for these pollutants. Note, however, that the specifications and emissions limitations in this certification do not establish BACT.

{Note: SO_2 emissions for gas firing are estimated at 9.8 lb/hour for simple and combined cycle operation and 12.8 lb/hour for combined cycle operation with duct burning. SAM emissions are estimated to be less than 10% of the SO_2 emissions.}

e. Compliance with the VOC standards shall be demonstrated by conducting tests in accordance with EPA Method 25A. Optionally, EPA Method 18 may be also be performed to deduct emissions of methane and ethane. The emission standards are based on VOC measured as methane.

f. Each SCR system shall be designed and operated for an initial ammonia slip target of less that 5 ppmvd corrected to 15% oxygen based on the average of three test runs. Compliance with the ammonia slip standard shall be demonstrated by conducting tests in accordance with EPA Method CTC-027.

{General Notes: "DB" means duct burning. "PA" means power augmentation. "SCR" means selective catalytic reduction. "NA" means not applicable. The mass emission rate standards are based on a turbine

inlet condition of 59° F and may be adjusted to actual test conditions in accordance with the performance curves and/or equations on file with the Department.}

G. The duct burners are also subject to the provisions of Subpart Da of the New Source Performance Standards in 40 CFR 60.

H. If the steam-electrical turbine generator is off line, the permittee is authorized to operate the gas turbine/HRSG systems by dumping steam to the condenser. When operating in this manner, each unit shall comply with the standards established for combined cycle operation with ammonia injection (SCR).

I. The permittee shall install, calibrate, maintain, and operate continuous emission monitoring systems (CEMS) to measure and record the emissions of CO and NO_X from each gas turbine in a manner sufficient to demonstrate continuous compliance with the CEMS emission standards of this section. Each monitoring system shall be installed, calibrated, and properly functioning prior to the initial performance tests. Within one working day of discovering emissions in excess of a CO or NOx standard (and subject to the specified averaging period), the permittee shall notify Air Quality Division, DEP Southwest District Office.

1. Each CO monitor shall be certified pursuant to 40 CFR 60, Appendix B, Performance Specification 4 or 4A. Quality assurance procedures shall conform to the requirements of 40 CFR 60, Appendix F, and the Data Assessment Report of Section 7 shall be made each calendar quarter, and reported semiannually to the Air Quality Division, DEP Southwest District Office. The RATA tests required for the CO monitor shall be performed using EPA Method 10 in Appendix A of 40 CFR 60 and shall be based on a continuous sampling train. The CO monitor span values shall be set appropriately considering the allowable methods of operation and corresponding emission standards.

2. Each NOx monitor shall be certified, operated, and maintained in accordance with the requirements of 40 CFR Part 75. Record keeping and reporting shall be conducted pursuant to Subparts F and G in 40 CFR Part 75. The RATA tests required for the NO_X monitor shall be performed using EPA Method 20 or 7E in Appendix A of 40 CFR 60. In addition to the requirements of Appendix A of 40 CFR 75, the NOx monitor span values shall be set approximately considering the allowable method of operation and corresponding emission standards.

J. The oxygen (O2) content or carbon dioxide (CO2) content of the flue gas shall also be monitored at the location where CO and NOx are monitored to correct the measured emissions rates to 15% oxygen. If a CO2 monitor is installed, the oxygen content of the flue gas shall be calculated by the CEMS using F-factors that are appropriate for the fuel fired. Each monitor shall comply with the performance and quality assurance requirements of 40 CFR Part 75.

K. Hourly average values shall begin at the top of each hour. Each hourly average value shall be computed using at least one data point in each fifteen-minute quadrant of an hour, where the unit combusted fuel during that quadrant of an hour. Notwithstanding this requirement, an hourly value shall be computed from at least two data points separated by a minimum of 15 minutes (where the unit operates for more than one quadrant of an hour). If less than two such data points are available, the hourly average value is not valid. The permittee shall use all valid measurements or data points collected during an hour to calculate the hourly average values. The CEMS shall be designed and operated to sample, analyze, and record data evenly spaced over an hour. If the CEMS measures concentration on a wet basis, the CEM system shall include provisions to determine the moisture content of the exhaust gas and an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Alternatively, the owner or operator may develop through manual stack test measurements a curve of moisture contents in the exhaust gas versus load for each allowable fuel, and use these typical values in an algorithm to enable correction of the monitoring results to a dry basis (0% moisture). Final results of the CEMS shall be expressed as ppmvd, corrected to 15% oxygen. The CEMS shall be used to demonstrate compliance with the CEMS emission standards for CO and NOx as specified in this certification. For purpose of determining compliance with the CEMS emission standard of this certification, missing (or excluded) data shall not be submitted. Upon request by the Department, the CEMS emission rates shall be corrected to ISO conditions to demonstrate compliance with the applicable standards of 40 CFR 60.332.

L. A 24-hour block shall begin at midnight of each operating day and shall be calculated from 24 consecutive hourly average emission rate values. If a unit operates less than 24 hours during the block, the 24-hour block average shall be the average of available valid hourly average emission rate values for the 24-hour block. For purposes of determining compliance with the 24-hour CEMS standards, missing (or excluded) data shall not be substituted. Instead the 24-hour block average shall be determined using the remaining hourly data in the 24-hour block.

M. Each CEMS shall monitor and record emissions during all operations including all episodes of startup, shutdown, malfunction, DLN tuning, and steam blows. CEMS emissions data recorded during such episodes may be excluded from the corresponding CEMS compliance demonstration subject to the provisions of Specific Conditions XXIII.W.4 and XXIII.W.7.

All periods of data excluded shall be consecutive for each such episode. The permittee shall minimize the duration of data excluded for such episodes to the extent practicable. Data recorded during such episodes shall not be excluded if the episode was caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented. Best operational practices shall be used to minimize hourly emissions that occur during such episodes. Emissions of any quantity or duration that occur entirely or in part from poor maintenance, poor operation, or any other equipment or process failure, which may reasonably be prevented, shall be prohibited.

N. Monitor availability for the CEMS shall be 95% or greater in any calendar quarter. The report required in this certification shall be used to demonstrate monitor availability. In the event 95% availability is not achieved, the permittee shall provide the Department with a report identifying the problems in achieving 95% availability and a plan of corrective actions that will be taken to achieve 95% availability. The permittee shall implement the reported corrective actions within the next calendar quarter. Failure to take corrective actions or continued failure to achieve the minimum monitor availability shall be violations of this certification, except as otherwise authorized by the Department.

O. In accordance with the manufacturer's specifications, the permittee shall install, calibrate, maintain and operate an ammonia flow meter to measure and record the ammonia injection rate to the SCR system. The permittee shall document the general range of ammonia flow rates required to meet allowable emissions levels over the range of load conditions allowed by this certification by comparing NO_X emissions recorded by the CEM system with ammonia flow rates recorded using the ammonia flow meter. During NO_X monitor downtimes or malfunctions, the permittee shall operate at the ammonia flow rate that is consistent with the documented flow rate for the combustion turbine load.

P. The permittee shall monitor and record the operating rate of each gas turbine and HRSG duct burner system on a daily average basis, considering the number of hours of operation during each day (including the times of startup, shutdown and malfunction). Such monitoring shall be made using a monitoring component of the CEM system required above, or by monitoring daily rates of consumption and heat content of each allowable fuel in accordance with the provisions of 40 CFR 75 Appendix D.

Q. By the fifth calendar day of each month, the permittee shall record the following in a written or electronic log for each gas turbine for the previous month of operation: consumption of each fuel, the hours of operation, the hours of power augmentation, the hours of peaking, the hours of duct firing, and the updated 12-month rolling totals for each. Information recorded and stored as an electronic file shall be available for inspection and printing within at least three days of a request by the Department. The fuel consumption shall be monitored in accordance with the provisions of 40 CFR 75 Appendix D.

R. The permittee shall demonstrate compliance with the fuel sulfur specification of this certification by maintaining records of the sulfur content of the natural gas being supplied based on the vendor's analysis for each month of operation. Methods for determining the sulfur content of the natural gas shall be ASTM methods D4084-82, D3246-81 (or more recent versions) in conjunction with the provisions of 40 CFR 75 Appendix D.

S. Within one working day of a malfunction that causes emissions in excess of a standard (subject to the specified averaging periods), the permittee shall notify the Air Quality Division, DEP Southwest District Office. The notification shall include a preliminary report of: the nature, extent, and duration of the emissions; the probable cause of the emissions; and the actions taken to correct the problem. If requested by the Air Quality Division, DEP Southwest District Office, the permittee shall submit written quarterly reports report of the malfunctions.

T. Within 30 days following the end of each calendar quarter, the permittee shall submit a report to the Air Quality Division, DEP Southwest District Office summarizing emissions in excess of an NSPS standard. For purposes of reporting emissions in excess of NSPS standards, excess emissions from the gas turbine are defined as: any CEMS hourly average value exceeding the NSPS NO_X emission standard; and any daily period during which the sulfur content of the fuel being fired in the gas turbine exceeds the NSPS standard. For purposes of reporting emissions in excess of NSPS standards, excess emissions from duct firing are defined as: NO_X or PM emissions in excess of the NSPS standards except during periods of startup, shutdown, or malfunction; and SO2 emissions in excess of the NSPS standards except during startup or shutdown.

U. Within 30 days following the end of each quarter, the permittee shall submit a report to the Air Quality Division, DEP Southwest District Office summarizing periods of excess emissions. The information shall be summarized for simple/combined cycle startups, simple/combined cycle shutdowns, malfunctions, and major tuning sessions. In addition, the report shall summarize the CEMS systems monitor availability for the previous quarter.

V. The permittee is authorized to install, operate, and maintain four fuel heaters fired exclusively with natural gas at a maximum heat input rate of 24 MMBtu per hour. The fuel heaters will be designed to preheat the natural gas during simple cycle operation and during startup to combined cycle operation. For full combined cycle operation, feedwater heat exchangers will preheat the natural gas. *{Note: In accordance with Air Permit No. PSD-FL-286, construction of two gas-fired fuel heaters has been completed.}*

W. Excess Emissions

1. In order to ensure that_good operating practices to reduce emissions are followed, all operators and supervisors shall be properly trained to operate and maintain the gas turbines, HRSGs, and pollution control systems in accordance with the guidelines and procedures established by each manufacturer. The training shall include good operating practices as well as methods of minimizing excess emissions.

2. Excess emissions caused entirely or in part by poor maintenance, poor operation or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction, shall be prohibited. All such preventable emissions shall be included in any compliance determinations based on CEMS data.

3. Visible emissions due to startups, shutdowns, and malfunctions shall not exceed 10% opacity except for up to ten, 6-minute averaging periods during a calendar day, which shall not exceed 20% opacity. [Rule 62-212.400(BACT), F.A.C.]

4. Excess Emissions Allowed

a. As specified in this condition, excess emissions resulting from startup, shutdown, and documented malfunctions are allowed provided that operators employ the best operational practices to minimize the amount and duration of emissions during such incidents. A "documented malfunction" means a malfunction that is documented within one working day of detection by contacting the Air Quality Division, DEP Southwest District Office by telephone, facsimile transmittal, or electronic mail. For each gas turbine/HRSG system, excess emissions resulting from startup, shutdown, or documented malfunctions shall not exceed two hours in any 24-hour period except for the following specific cases.

1) For cold startup of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed six hours in any 24-hour period. Cold startup of the steam turbine system shall be completed within twelve hours. A cold "startup of the steam turbine system" is defined as startup of the 4-on-1 combined cycle system following a shutdown of the steam turbine lasting at least 48 hours. *{Note: During a cold startup of the steam turbine system, each gas turbine/HRSG system is sequentially brought on line at low load to gradually increase the temperature of the steam-electrical turbine and prevent thermal metal fatigue. Note that shutdowns and documented malfunctions are separately regulated in accordance with the requirements of this condition.}*

2) For shutdown of the steam turbine system, excess emissions from any gas turbine/HRSG system shall not exceed three hours in any 24-hour period.

3) For cold startup of a gas turbine/HRSG system, excess emissions shall not exceed four hours in any 24-hour period. "Cold startup of a gas turbine/HRSG system" is defined as a startup after the pressure in the high-pressure (HP) steam drum falls below 450 psig for at least a one-hour period.

b. Ammonia injection shall begin as soon as operation of the gas turbine/HRSG system achieves the operating parameters specified by the manufacturer. As authorized by Rule 62-210.700(5), F.A.C., the above conditions allow excess emissions only for specifically defined periods of startup, shutdown, and documented malfunction of the gas turbines.

5. Work Practice Standard and Load Restriction

a. Each unit will be operated according to manufacturer specifications and control systems. The CT control system is designed to reach Mode 5Q (i.e. five burners plus quaternary pegs in operation) within 15 minutes following gas turbine ignition and crossfire.

b. A Best Operating Practice procedure for minimizing emissions during startup and shutdown shall be submitted to the Department within 60 days following determination of initial compliance with emission limits when operating in combined cycle mode.

c. Except for initial steam blows, startup and shutdown, malfunctions, commissioning and recommissioning, operation at loads where the DLN 2.6 system is not in pre-mix mode is prohibited.

6. Initial Steam Blows

a. Prior to completing the conversion from simple cycle to combined cycle operation, the permittee is authorized to operate each gas turbine at loads below 50% for the purpose of cleaning the HRSG piping system and piping connecting the HRSG to the steam turbine. Prior to conducting any steam blows, the permittee shall submit a proposed schedule. On the first day of conducting steam blows, the permittee shall notify the Air Quality Division, DEP Southwest District Office that the process has begun. The permittee shall complete this process within 90 days of conducting the initial steam blow. For good cause, the permittee may request that the Air Quality Division, DEP Southwest District Office extend the steam blow period. During the steam blows, the following conditions apply:

1) The permittee shall take all precautions to minimize the extent and duration of excess emissions.

2) Each gas turbine shall fire only natural gas and each CEMS shall be on line and functioning properly.

3) CO and NO_X emissions may exceed the BACT limits specified in the PSD permit; however, NO_X emissions shall not exceed the NSPS Subpart GG limit of 110 ppmvd corrected to 15% oxygen based on a 24-hour block average. If the NSPS standard is exceeded, the permittee shall notify the Air Quality Division, DEP Southwest District Office within one working day of the incident.

b. Within 30 days of completing the initial steam blows, the permittee shall submit a report to the Bureau of Air Regulation and the Air Quality Division, DEP Southwest District Office summarizing the daily emissions resulting from each steam blow. {Permitting Note: It is estimated that steam blows will occur intermittently over a 30-day period for each gas turbine/HRSG system followed by a similar 60-day period of intermittent steam blows for the common piping system serving the four interconnected combined cycle units. It is not expected that steam blows would occur every day during these periods. This condition only applies if simple cycle operation begins prior to combined cycle operation and NSPS compliance tests for simple cycle operation have been performed}

7. CEMS data collected during initial or other major DLN tuning sessions shall be excluded from the CEMS compliance demonstration provided the tuning session is performed in accordance with the manufacturer's specifications. A "major tuning session" would occur after completion of initial construction, a combustor change-out, a major repair or maintenance to a combustor, or other similar circumstances. Prior to performing any major tuning session, the permittee shall provide the Air Quality Division, DEP Southwest District Office with an advance notice that details the activity and proposed tuning schedule. The notice may be by telephone, facsimile transmittal, or electronic mail.

X. Emissions Performance Testing

1. Required tests shall be performed in accordance with the following reference methods.

Method	**Description of Method and Comments**
CTM-027	Procedure for Collection and Analysis of Ammonia in Stationary Source {Notes: This is an EPA conditional test method. The minimum detection limit shall be 1 ppm.}
7E	Determination of Nitrogen Oxide Emissions from Stationary Sources
9	Visual Determination of the Opacity of Emissions from Stationary Sources
10	Determination of Carbon Monoxide Emissions from Stationary Sources {Notes: The method shall be based on a continuous sampling train. The ascarite trap may be omitted or the interference trap of section 10.1 may be used in lieu of the silica gel and ascarite traps.}
18	Measurement of Gaseous Organic Compound Emissions by Gas Chromatography {Note: EPA Method 18 may be used (optional) concurrently with EPA Method 25A to deduct emissions of methane and ethane from the measured VOC emissions.}
20	Determination of Nitrogen Oxides, Sulfur Dioxide and Diluent Emissions from Stationary Gas Turbines
25A	Determination of Volatile Organic Concentrations

Except for Method CTM-027, the above methods are described in 40 CFR 60, Appendix A, and adopted by reference in Rule 62-204.800, F.A.C. Method CTM-027 is published on EPA's Technology Transfer Network Web Site at "http://www.epa.gov/ttn/emc/ctm.html". No other methods may be used for compliance testing unless prior written approval is received from the Department.

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2. Each gas turbine shall be stack tested to demonstrate initial compliance with the emission standards for CO, NO_X, VOC, visible emissions, and ammonia slip. The tests shall be conducted within 60 days after achieving the maximum

production rate at which the unit will be operated for each unit configuration (i.e., simple cycle an combined cycle operation), but not later than 180 days after the initial startup of each unit configuration. Each unit shall be tested under all operating scenarios as required in Specific Condition No. 10. CEMS data collected during the required Relative Accuracy Test Assessments (RATA) may be used to demonstrate compliance with the initial CO and NOx standards. With appropriate flow measurements (or fuel measurements and approved F-factors), CEMS data may also be used to demonstrate compliance with the CO and NO_X mass emissions standards. CO and NOx emissions recorded by the CEMS shall also be reported for each run during tests for visible emissions, VOC and ammonia slip. Initial CO and VOC emissions tests performed during simple cycle operation may be used to satisfy the initial test requirement for similar operation in combined cycle mode. The Department may require the permittee to conduct additional tests after major replacement or repair of any air pollution control equipment, such as the SCR catalyst, DLN combustors, etc.

V. The permittee shall demonstrate continuous compliance with the CO and NO_X emissions standards based on data collected by the certified CEMS. Within 45 days of conducting any Relative Accuracy Test Assessments (RATA) on a CEMS, the permittee shall submit a report to the Compliance Authority summarizing results of the RATA. Compliance with the CO emission standards also serves as an indicator of efficient fuel combustion, which reduces emissions of particulate matter and volatile organic compounds.

W. During each federal fiscal year (October 1st to September 30th), each gas turbine shall be tested to demonstrate compliance with the emission standards for visible emissions and ammonia slip. NOx emissions recorded by the CEMS shall be reported for each ammonia slip test run. CO emissions recorded by the CEMS shall be reported for the visible emissions observation period. *{Note: After initial compliance with the VOC standards are demonstrated, annual compliance tests for VOC emissions are not required. Compliance with the continuously monitored CO standards shall indicate efficient combustion and low VOC emissions.}*

X. If the tested ammonia slip rate for a gas turbine exceeds 5 ppmvd corrected to 15% oxygen when firing natural gas during the annual test, the permittee shall:

a. Begin testing and reporting the ammonia slip for each subsequent calendar quarter;

b. Before the ammonia slip exceeds 7 ppmvd corrected to 15% oxygen, take corrective actions that result in lowering the ammonia slip to less than 5 ppmvd corrected to 15% oxygen; and

c. Test and demonstrate that the ammonia slip is no more than 5 ppmvd corrected to 15% oxygen within 15 days after completing the corrective actions. Corrective actions may include, but are not limited to, adding catalyst, replacing catalyst, or other SCR system maintenance or repair. After demonstrating that the ammonia slip level is no more than 5 ppmvd corrected to 15% oxygen, testing and reporting shall resume on an annual basis

XXIX. WATER

The construction and operation of the Manatee Unit 3 project shall not cause or contribute to violation of any applicable provision of National Pollutant Discharge Elimination System (NPDES) Permit No. FL 0002267 Rev A or as subsequently revised, Chapters 62-4 through 62-699, F.A.C., and rules of the Department and the Southwest Florida Water Management District.

Any violation of such permit or rules shall constitute a violation of these conditions of certification.

XXX. DOMESTIC WASTE

The Licensee is hereby authorized to operate the facilities shown in the Manatee Unit 3 Site Certification Application and other documents on file with the Department and made a part hereof. The Licensee shall give the Department written notice at least 60 days before inactivation or abandonment of a wastewater facility and shall specify what steps will be taken to safeguard public health and safety during and following inactivation or abandonment

XXXI. INDUSTRIAL WASTE

The Licensee is hereby authorized to operate the facilities shown in the Manatee Unit 3 Site Certification Application and other documents on file with the Department and made a part hereof and as specifically described in NPDES Permit No. FL 0002267 Rev A or as subsequently revised.

XXXII. SOLID AND HAZARDOUS WASTE

No solid or hazardous waste is to be permanently stored onsite.

XXXIII. WATER MANAGEMENT DISTRICT

A. Reports

1. All Water Management District-related reports required by the Site Certification shall be submitted to the Southwest Florida Water Management District on or before the fifteenth (15^{th}) day of the month, unless otherwise indicated, following data collection and shall be addressed to:

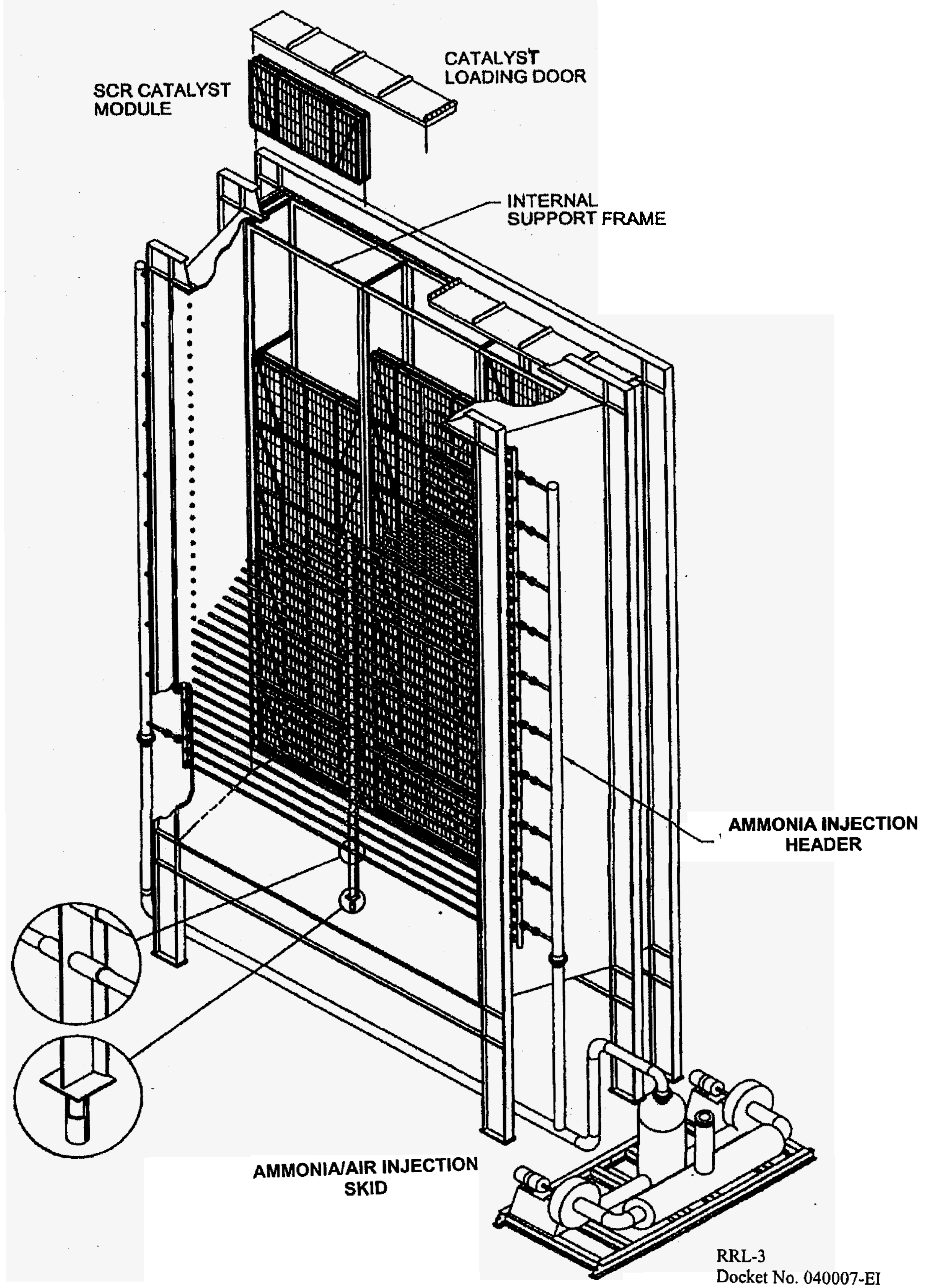
Permit Data Section, Records and Data Department
Southwest Florida Water Management District
2379 Broad Street

FLORIDA POWER & LIGHT COMPANY

DRAWING OF A TYPICAL SCR MODULE

RRL-3
DOCKET NO. 040007-EI
FPL WITNESS: R. R. LABAUVE
EXHIBIT ______________
PAGES 1-2

TYPICAL SCR MODULE



RRL-3
Docket No. 040007-EI
FPL Witness R. R. LaBauve
Exhibit ________
Page 2 of 2