GENERATING PERFORMANCE INCENTIVE FACTOR

REWARD/PENALTY TABLE (ACTUAL)

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: OCTOBER,1995 THROUGH MARCH,1996

GENERATING PERFORMANCE INCENTIVE POINTS (GPIF)	FUEL SAVINGS/(LOSS) ($000)	GENERATING PERFORMANCE INCENTIVE FACTOR ($000)
+10	9490.20	9108.80
+ 9	8541.18	8197.92
+ 8	7592.16	7287.04
+ 7	6643.14	6376.16
+ 6	5694.12	5465.28
+ 5	4745.10	4554.40
+ 4	3796.08	3643.52
+ 3	2847.06	2732.64
+ 2 <-- 2.1376	1898.04	1947.11 --> 1821.76
+ 1	949.02	910.88
0	0.00	0.00
- 1	(939.78)	(910.88)
- 2	(1879.56)	(1821.76)
- 3	(2819.34)	(2732.64)
- 4	(3759.12)	(3643.52)
- 5	(4698.90)	(4554.40)
- 6	(5638.68)	(5465.28)
- 7	(6578.46)	(6376.16)
- 8	(7518.24)	(7287.04)
- 9	(8458.02)	(8197.92)
-10	(9397.80)	(9108.80)

DOCUMENT NUMBER-DATE
07699 JUL 22 96
FPSC-RECORDS/REPORTING

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 960001-EI EXHIBIT NO ____
COMPANY/WITNESS: FPL / Silva
DATE: 7/24/96

Issued By: Florida Power & Light Company

Docket No.: 960001-EI
FPL Witness: R. Silva
Exhibit: No.: ____
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REVISED

OCTOBER,1995 THROUGH MARCH,1996

DERIVATION OF SYSTEM ACTUAL GPIF POINTS

PLANT/UNIT		PERFORMANCE INDICATOR	WEIGHTING FACTOR %	UNIT POINTS	WEIGHTED UNIT POINTS
CAPE CANAVERAL	1	EAF	0.17	10.00	0.0170
		ANOHR	1.93	1.90	0.0367
CAPE CANAVERAL	2	EAF	0.36	10.00	0.0360
		ANOHR	0.84	0.00	0.0000
LAUDERDALE	4	EAF	1.65	8.00	0.1320
		ANOHR	1.79	4.25	0.0761
LAUDERDALE	5	EAF	1.38	10.00	0.1380
		ANOHR	1.79	1.53	0.0274
FORT MYERS	2	EAF	0.32	5.01	0.0160
		ANOHR	1.03	-10.00	-0.1030
PORT EVERGLADES	3	EAF	0.33	10.00	0.0330
		ANOHR	1.48	7.52	0.1113
PORT EVERGLADES	4	EAF	0.18	0.10	0.0002
		ANOHR	3.49	8.80	0.3071
PUTNAM	1	EAF	0.51	-10.00	-0.0510
		ANOHR	1.01	-10.00	-0.1010
PUTNAM	2	EAF	0.37	-2.59	-0.0096
		ANOHR	1.55	-1.27	-0.0197
ST. JOHNS RIVER	1	EAF	1.83	-5.24	-0.0959
		ANOHR	0.83	0.00	0.0000
TURKEY POINT	1	EAF	0.11	10.00	0.0110
		ANOHR	0.79	0.00	0.0000
TURKEY POINT	2	EAF	0.13	7.17	0.0093
		ANOHR	2.41	10.00	0.2410
TURKEY POINT	3	EAF	11.87	3.33	0.3953
		ANOHR	2.44	1.11	0.0244
TURKEY POINT	4	EAF	12.09	10.00	1.2090
		ANOHR	4.27	0.00	0.0000
ST. LUCIE	1	EAF	17.29	-10.00	-1.7290
		ANOHR	2.95	0.00	0.0000
ST. LUCIE	2	EAF	14.44	10.00	1.4440
		ANOHR	4.81	3.18	0.1530
SCHERER	4	EAF	0.54	10.00	0.0540
		ANOHR	3.06	-7.35	-0.2249
GPIF SYSTEM TOTAL:			100.00		2.1376

FROM: OCTOBER,1995 THROUGH MARCH,1996

1		2	3	4	5	6	7	8	9	
			ACTUAL		TARGET(2)	ADJUST.(3)		ADJUST.(5)		ACTUAL
					ANOHR AT	TO	TARGET(4)	ACTUAL	GPIF(6)	FUEL
		HEAT RATE (1)	NOF	ANOHR	ACTUAL NOF	ANOHR	ANOHR	ANOHR	FROM	SAV/(LOSS)
UNIT		FORMULA	%	BTU/KWH	BTU/KWH	BTU/KWH	BTU/KWH	BTU/KWH	TABLES	($000)
CAPE CANAVERAL	1	ANOHR= -10.97 NOF +10226.	56.2	9507	9609	-102	9330	9228.	1.90	34
CAPE CANAVERAL	2	ANOHR= -4.22 NOF + 9782.	60.5	9549	9526	23	9436	9459.	0.00	0
LAUDERDALE	4	ANOHR= -10.19 NOF + 8334.	89.4	7318	7424	-106	7288	7182.	4.25	72
LAUDERDALE	5	ANOHR= -14.77 NOF + 8769.	91.8	7327	7413	-86	7248	7162.	1.53	25
FORT MYERS	2	ANOHR= -11.02 NOF +10245.	55.3	9833	9635	198	9308	9506.	-10.00	(-97)
PORT EVERGLADES	3	ANOHR= -27.62 NOF +11658.	58.7	9917	10036	-119	9133	9014.	7.52	106
PORT EVERGLADES	4	ANOHR= -30.59 NOF +11754.	55.0	9850	10071	-221	9132	8911.	8.80	291
PUTNAM	1	ANOHR= -1.09 NOF + 8884.	79.7	8986	8797	189	8777	8966.	-10.00	(-95)
PUTNAM	2	ANOHR= -5.23 NOF + 9129.	81.7	8791	8702	89	8596	8685.	-1.27	(-18)
ST. JOHNS RIVER	1	ANOHR= -37.01 NOF +12991.	95.4	9415	9460	-45	9335	9290.	0.00	0
TURKEY POINT	1	ANOHR= -9.56 NOF +10072.	56.2	9521	9535	-14	9279	9265.	0.00	0
TURKEY POINT	2	ANOHR= -14.02 NOF +10659.	59.4	9450	9826	-376	9524	9148.	10.00	228
TURKEY POINT	3	ANOHR= -14.12 NOF +12332.	98.8	10855	10936	-81	10874	10793.	1.00	23
TURKEY POINT	4	ANOHR= -24.99 NOF +13477.	102.2	10880	10923	-43	10912	10869.	0.00	0
ST. LUCIE	1	ANOHR= -25.85 NOF +13448.	96.7	11017	10948	69	10828	10897.	0.00	0
ST. LUCIE	2	ANOHR= -29.67 NOF +13872.	97.5	10851	10979	-128	10856	10728.	3.18	145
SCHERER	4	ANOHR= -6.80 NOF +10541.	90.6	10050	9925	125	9939	10064.	-7.35	(-213)
										501

1) THESE FORMULAS ARE AS APPROVED BY THE COMMISION IN THE PROJECTED DATA AND REFLECT ON MONTHLY ACTUAL DATA SUBMITTED.
2) CALCULATED FROM ANOHR FORMULA IN COLUMN 2 USING ACTUAL NOF IN COLUMN 3.
3) ADJUSTMENT TO ANOHR=ACTUAL ANOHR - TARGET ANOHR AT ACTUAL NOF (COLUMN 6 = COLUMN 4 - COLUMN 5.)
4) AT TARGET NOF AS APPROVED BY THE COMMISSION IN PROJECTED DATA.
5) AT TARGET NOF, ADJUSTED ACTUAL ANOHR = TARGET ANOHR + ADJUSTMENTS (COLUMN 8 = COLUMN 7 + COLUMN 6).
6) OBTAINED FROM GPIF POINTS TABLES AS APPROVED BY THE COMMISSION IN PROJECTED TARGETS.

GENERATING PERFORMANCE INCENTIVE POINTS TABLE

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: OCTOBER,1995 THROUGH MARCH,1996
UNIT: PORT EVERGLADES 3

EQUIVALENT AVAILABILITY POINTS	FUEL SAVINGS/(LOSS) ($000)	ADJUSTED ACTUAL EQUIVALENT AVAILABILITY	AVERAGE HEAT RATE POINTS	FUEL SAVINGS(LOSS) ($000)	ADJUSTED ACTUAL AVG. HEAT RATE
+10	30.90	86.10<-Adj. Act.	+10	140.58	9000
+ 9	27.81	85.80 EAF=90.1	+ 9	126.52	9005
+ 8	24.72	85.50	+ 8	112.46	9011
+ 7	21.63	85.20	+ 7	98.40	9017<-Adj.Act.
+ 6	18.54	84.90	+ 6	84.35	9023 HR= 9014
+ 5	15.45	84.60	+ 5	70.29	9029
+ 4	12.36	84.30	+ 4	56.23	9034
+ 3	9.27	84.00	+ 3	42.17	9040
+ 2	6.18	83.70	+ 2	28.12	9046
+ 1	3.09	83.40	+ 1	14.06	9052
				0.00	9058
0	0.00	83.10	0	0.00	9133
				0.00	9208
- 1	(3.09)	82.80	- 1	(14.06)	9213
- 2	(6.18)	82.50	- 2	(28.12)	9219
- 3	(9.27)	82.20	- 3	(42.17)	9225
- 4	(12.36)	81.90	- 4	(56.23)	9231
- 5	(15.45)	81.60	- 5	(70.29)	9237
- 6	(18.54)	81.30	- 6	(84.35)	9242
- 7	(21.63)	81.00	- 7	(98.40)	9248
- 8	(24.72)	80.70	- 8	(112.46)	9254
- 9	(27.81)	80.40	- 9	(126.52)	9260
-10	(30.90)	80.10	-10	(140.58)	9266

WEIGHTING FACTOR = 0.33

WEIGHTING FACTOR = 1.48

Issued By Florida Power & Light Company

Docket No.: 960001-EI
FPL Witness: R. Silva
Exhibit No.: ______
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REVISED

DOCUMENT NO. 1
FLORIDA POWER AND LIGHT COMPANY
RESPONSE TO STAFF'S THIRD SET
INTERROGATORY NO. 19

RS-4
DOCKET NO. 960001-EI
FPL WITNESS: R. SILVA
EXHIBIT ______
PAGES 1 - 11

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 960001-EI EXHIBIT NO 5
COMPANY/WITNESS: FPL/Silva
DATE: [illegible]

19. Q. How will the outages since April 1995 at the St. Lucie nuclear units affect Florida Power and Light Company's Generating Performance Incentive Factor reward/penalty amount for the period April through September 1995? The response should include all assumptions and calculations.

A. The unplanned outages at St. Lucie Unit 1 during August and September, 1995, which followed the shutdown caused by Hurricane Erin, will result in Florida Power & Light receiving a GPIF maximum Equivalent Availability Factor (EAF) penalty of approximately $1.3 million for St. Lucie Unit 1. Please note that during the period of April 1995 to July 1995, prior to the hurricane, St. Lucie Unit 1 had performed well above its approved EAF target. Consequently, if Unit 1 had performed at its target level during August and September, FPL would have received a maximum reward of $1.3 million for Unit 1. Therefore the net "loss" to FPL for the outages at St. Lucie Unit 1 is more than $2.6 million. Consistent with previous periods, the Equivalent Availability Factors (EAF's) of the St. Lucie units have been adjusted to remove the effects of externally caused events. Therefore, the hours offline due to Hurricane Erin as well as the delay in unit start up due to the vehicle lodged in the discharge canal have been removed from the EAF calculations

During the same April 1995 through September 1995 GPIF period, St. Lucie Unit 2 performed well above its approved EAF target and achieved a GPIF maximum EAF reward of almost $1.1 million. Therefore the combined EAF performance of the St. Lucie nuclear plant was a penalty of more than $0.2 million. The FPL nuclear units at the Turkey Point site also performed well above their approved targets during the same period with maximum rewards for each unit's EAF performance

During the 1990's FPL's nuclear units have exceeded nuclear industry standards. Since 1991, all four of FPL's nuclear units have consistently performed above the nuclear industry average for forced (unplanned) outages. For example, while the industry average for forced outages was approximately 10.6%, FPL's nuclear units had forced outage rates of less than 4%. Other significant gains in nuclear unit availability were achieved through the reduction in the length of planned outages. Between 1992 and 1994 the average number of days off line for planned outages at FPL's nuclear sites has decreased from more than 63 days to less than 44 days. In contrast, the nuclear industry average for planned outages was approximately 65 days in 1992 and 56 days in 1994. FPL's excellent nuclear performance has provided substantial savings to our customers in replacement fuel costs.

The GPIF program has rewarded FPL for having its nuclear units perform well. In this instance, the GPIF program (as intended) has penalized FPL at St. Lucie Unit 1, as a result of its outages during August and September.

VERSION # 15.0
ORIGINAL SHEET NO. 6.202.033

ACTUAL PERFORMANCE DATA
COMPANY: FLORIDA POWER AND LIGHT
PERIOD OF: APRIL 1995 THRU SEPTEMBER 1995

PLANT / UNIT: TURKEY POINT #3 PTP3

		APR.	MAY	JUN.	JUL.	AUG.	SEP.	6 MON.
1.	EAF (%)	94.2	100.0	97.1	100.0	99.5	10.0	83.7
2.	PH	719.0	744.0	720.0	744.0	744.0	720.0	4391.0
3.	SH	679.00	744.00	720.00	744.00	744.00	72.17	3703.17
4.	RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5.	UH	40.0	0.0	0.0	0.0	0.0	647.8	687.8
6.	POH	0.0	0.0	0.0	0.0	0.0	647.8	647.8
7.	FOH	40.0	0.0	0.0	0.0	0.0	0.0	40.0
8.	MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9.	PPOH	0.00	0.00	3.33	0.00	0.00	0.00	3.33
10.	LR PP (MW)	0.00	0.00	421.00	0.00	0.00	0.00	421.00
11.	PFOH	2.48	0.00	0.00	0.00	11.72	0.00	14.20
12.	LR PF (MW)	544.00	0.00	0.00	0.00	210.00	0.00	268.41
13.	PMOH	0.00	0.00	39.63	0.00	0.00	0.00	39.63
14.	LR PM (MW)	0.00	0.00	319.92	0.00	0.00	0.00	319.92
15.	NSC (MW)	666.0	666.0	666.0	666.0	666.0	666.0	666.0

NOTE: LINE 17 IS DATA WHEN THE UNIT IS SYNCHRONIZED TO THE SYSTEM

		APR.	MAY	JUN.	JUL.	AUG.	SEP.	6 MON.
16.	OPER BTU (MBTU)	5030162	5557946	5248244	5577594	5529768	458174	27401888
17.	NET GEN	456014	495002	466379	495897	492271	38755	2444318
18.	ANOHR (BTU/KWH)	11031	11228	11253	11247	11233	11822	11210
19.	NOF (%)	100.8	99.9	97.3	100.1	99.3	80.6	99.1
20.	NPC (MW)	680	680	666	666	666	666	671

21. ANOHR EQUATION

ANOHR = A + B (N.O.F.)
A = 13193. B = -20.59

ISSUED BY: FLORIDA POWER & LIGHT CO.

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ORIGINAL SHEET NO. 6.202.034
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ACTUAL PERFORMANCE DATA
COMPANY: FLORIDA POWER AND LIGHT
PERIOD OF: APRIL 1995 THRU SEPTEMBER 1995
PLANT/UNIT: TURKEY POINT #3 PTP3

DATE	OUTAGE TYPE (1)	HOURS	(MW) AFFECTED	DESCRIPTION
4- 7	FPO	40.0	666	CONTROL ROD DRIVE PO
4- 9	PFO	2.5	544	CHEMISTRY HOLD
6-16	PPO	3.3	421	TURB VLV TEST
6-17	PMO	10.3	368	TPCW HX
6-17	PMO	29.3	303	WATERBOX CLEANING
8- 2	PFO	11.7	210	NE INTERCEPT VALVE
9- 4	PO	647.8	666	REFUELING OUTAGE

(1) FFO - FULL FORCED OUTAGE
PFO - PARTIAL FORCED OUTAGE
FMO - FULL MAINTENANCE OUTAGE
PMO - PARTIAL MAINTENANCE OUTAGE
PO - PLANNED OUTAGE
PPO - PARTIAL PLANNED OUTAGE
ISSUED BY: FLORIDA POWER & LIGHT CO.

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VERSION # 15.0
ORIGINAL SHEET NO. 6.202.035

ACTUAL PERFORMANCE DATA
COMPANY: FLORIDA POWER AND LIGHT
PERIOD OF: APRIL 1995 THRU SEPTEMBER 1995

PLANT / UNIT: TURKEY POINT #4 PTP4

	APR.	MAY	JUN.	JUL.	AUG.	SEP.	6 MON.
1. EAF (%)	100.0	100.0	96.9	100.0	97.7	100.0	99.1

2. PH	719.0	744.0	720.0	744.0	744.0	720.0	4391.0
3. SH	719.00	744.00	720.00	744.00	744.00	720.00	4391.00
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9. PPOH	0.00	0.00	1.67	0.00	3.50	0.00	5.17
10. LR PP (MW)	0.00	0.00	453.00	0.00	286.00	0.00	339.87
11. PFOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00
12. LR PF (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
13. PMOH	0.00	0.00	33.97	0.00	28.47	0.00	62.43
14. LR PM (MW)	0.00	0.00	418.48	0.00	363.12	0.00	393.24
15. NSC (MW)	666.0	666.0	666.0	666.0	666.0	666.0	666.0
NOTE: LINE 17 IS DATA WHEN THE UNIT IS SYNCHRONIZED TO THE SYSTEM							
16. OPER BTU (MBTU)	5387320	5578233	5243310	5580955	5454415	5398764	32642997
17. NET GEN	491394	499404	469438	498158	485227	485159	2928780
18. ANOHR (BTU/KWH)	10963	11170	11169	11203	11241	11128	11146
19. NOF (%)	102.6	100.8	97.9	100.5	97.9	101.2	100.1
20. NPC (MW)	680	680	666	666	666	666	671

21. ANOHR EQUATION

ANOHR = A + B (N.O.F.)
A = 13479. B = -22.62

ISSUED BY: FLORIDA POWER & LIGHT CO.

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ACTUAL PERFORMANCE DATA
COMPANY: FLORIDA POWER AND LIGHT
PERIOD OF: APRIL 1995 THRU SEPTEMBER 1995
PLANT/UNIT: TURKEY POINT #4 PTP4

DATE	OUTAGE TYPE (1)	HOURS	(MW) AFFECTED	DESCRIPTION
6- 9	PPO	1.7	453	TURB VLV TEST
6- 9	PMO	12.3	467	4ATPCW HX
6-10	PMO	21.7	391	WATERBOX CLEANING
8-22	PPO	3.5	286	TURB VLV TEST
8-22	PMO	16.1	396	TPCW HX
8-23	PMO	12.3	320	WATERBOX CLEANING

(1) FFO - FULL FORCED OUTAGE
PFO - PARTIAL FORCED OUTAGE
FMO - FULL MAINTENANCE OUTAGE
PMO - PARTIAL MAINTENANCE OUTAGE
PO - PLANNED OUTAGE
PPO - PARTIAL PLANNED OUTAGE

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VERSION # 15.0
ORIGINAL SHEET NO. 6.202.037

ACTUAL PERFORMANCE DATA
COMPANY: FLORIDA POWER AND LIGHT
PERIOD OF: APRIL 1995 THRU SEPTEMBER 1995

PLANT / UNIT: ST LUCIE #1 PSL1

	APR.	MAY	JUN.	JUL.	AUG.	SEP.	6 MON.
1. EAF (%)	100.0	100.0	99.5	88.6	2.1	0.0	65.9
2. PH	719.0	744.0	720.0	744.0	717.0	720.0	4329.8
3. SH	719.00	744.00	720.00	658.82	14.97	0.18	2856.97
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	0.0	0.0	0.0	85.2	702.0	719.8	1472.8
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	0.0	0.0	0.0	85.2	702.0	719.8	1472.8
8. MOH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9. PPOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00
10. LR PP (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
11. PFOH	0.00	0.00	6.60	0.00	0.00	0.00	6.60
12. LR PF (MW)	0.00	0.00	442.00	0.00	0.00	0.00	442.00
13. PMOH	0.00	0.00	0.00	0.00	0.00	0.00	0.00
14. LR PM (MW)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
15. NSC (MW)	839.0	839.0	839.0	839.0	839.0	839.0	839.0
NOTE: LINE 17 IS DATA WHEN THE UNIT IS SYNCHRONIZED TO THE SYSTEM							
16. OPER BTU (MBTU)	6634400	6855194	6584639	6012842	123389	0	26210464
17. NET GEN	611582	628354	598998	544598	10948	0	2394480
18. ANOHR (BTU/KWH)	10848	10910	10993	11041	11270	0	10946
19. NOF (%)	101.4	100.7	99.2	98.5	87.2	0.0	99.9
20. NPC (MW)	848	848	839	839	839	839	842

21. ANOHR EQUATION

ANOHR = A + B (N.O.F.)
A = 13019. B = -21.38

ISSUED BY: FLORIDA POWER & LIGHT CO.

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ACTUAL PERFORMANCE DATA
COMPANY: FLORIDA POWER AND LIGHT
PERIOD OF: APRIL 1995 THRU SEPTEMBER 1995
PLANT/UNIT: ST LUCIE #1 PSL1

DATE	OUTAGE TYPE (1)	HOURS	(MW) AFFECTED	DESCRIPTION
6-11	PFO	6.6	442	DC SAF.SYS.PWR.SUPP.
7- 8	FFO	19.4	839	RX TRIP-OPERATOR ERR
7- 9	FFO	31.5	839	RPS'C'WIDE RANGE NI
~~7-10~~	~~FFO~~	~~34.2~~	~~839~~	~~EXT.HIGG. VEH.DISCH.~~
~~8- 1~~	~~FFO~~	~~27.1~~	~~839~~	~~HURRICANE ERIN~~
8- 2	FFO	171.6	839	1A2 RCP SEAL
8- 9	FFO	188.5	839	PORVS
8-17	FFO	341.9	839	CONT. SPRAY SYSTEM
9- 1	FFO	1.6	839	CONT. SPRAY SYSTEM
9- 1	FFO	123.0	839	1B2 EMERG.DIESEL GEN
9- 6	FFO	109.3	839	1A DIESEL GENERATOR
9-10	FFO	25.8	839	1B1 SIT(ACCUMULATOR)
9-11	FFO	115.7	839	SAFETY VALVE V1201
9-16	FFO	36.4	839	SAF.VLV.V1200/V1202
9-18	FFO	21.1	839	CVCS VLV.V2427/V2428
9-19	FFO	71.4	839	1B DIESEL GENERATOR
9-22	FFO	48.3	839	1A DIESEL GENERATOR
9-24	FFO	15.6	839	1B DIESEL GENERATOR
9-24	FFO	2.3	839	1B1 RCP BREAKER
9-24	FFO	149.1	839	SAFETY VALVE V1202

(1) FFO - FULL FORCED OUTAGE
PFO - PARTIAL FORCED OUTAGE
FMO - FULL MAINTENANCE OUTAGE
PMO - PARTIAL MAINTENANCE OUTAGE
PO - PLANNED OUTAGE
PPO - PARTIAL PLANNED OUTAGE

FILED:
SUSPENDED:
EFFECTIVE:
DOCKET NO.:
ORDER NO.:

ISSUED BY: FLORIDA POWER & LIGHT CO.

VERSION # 15.0
ORIGINAL SHEET NO. 6.202.039

ACTUAL PERFORMANCE DATA
COMPANY: FLORIDA POWER AND LIGHT
PERIOD OF: APRIL 1995 THRU SEPTEMBER 1995

	PLANT / UNIT: ST LUCIE #2				PSL2		
	APR.	MAY	JUN.	JUL.	AUG.	SEP.	6 MON.
1. EAF (%)	99.0	99.7	98.6	93.8	92.1	93.9	96.2
2. PH	719.0	744.0	720.0	744.0	672.7	720.0	4319.7
3. SH	711.82	744.00	720.00	744.00	658.62	720.00	4298.43
4. RSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. UH	7.2	0.0	0.0	0.0	14.1	0.0	21.3
6. POH	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7. FOH	0.0	0.0	0.0	0.0	14.1	0.0	14.1
8. MOH	7.2	0.0	0.0	0.0	0.0	0.0	7.2
9. PPOH	1.52	1.32	0.00	1.33	7.50	1.67	13.33
10. LR PP (MW)	63.00	89.00	0.00	85.00	97.00	105.00	92.14
11. PFOH	0.00	2.28	4.10	171.25	240.15	193.37	611.15
12. LR PF (MW)	0.00	234.00	109.00	50.00	82.58	103.20	80.72
13. PMOH	0.00	4.45	30.55	107.27	31.83	47.30	221.40
14. LR PM (MW)	0.00	244.00	263.33	279.00	386.00	349.00	306.47
15. NSC (MW)	839.0	839.0	839.0	839.0	839.0	839.0	839.0
NOTE: LINE 17 IS DATA WHEN THE UNIT IS SYNCHRONIZED TO THE SYSTEM							
16. OPER BTU (MBTU)	6488157	6835013	6514148	6517646	5701417	6310619	38367000
17. NET GEN	587039	612852	583558	574803	504416	557750	3420418
18. ANOHR (BTU/KWH)	11052	11153	11163	11339	11303	11314	11217
19. NOF (%)	98.3	98.2	96.6	92.1	91.3	92.3	94.8
20. NPC (MW)	848	848	839	839	839	839	842

21. ANOHR EQUATION	ANOHR = A + B (N.O.F.) A = 13837. B = -29.60

ISSUED BY: FLORIDA POWER & LIGHT CO.

FILED:
SUSPENDED:
EFFECTIVE:
DOCKET NO.:
ORDER NO.:

ACTUAL PERFORMANCE DATA
COMPANY: FLORIDA POWER AND LIGHT
PERIOD OF: APRIL 1995 THRU SEPTEMBER 1995
PLANT/UNIT: ST LUCIE #2 PSL2

DATE	OUTAGE TYPE (1)	HOURS	(MW) AFFECTED	DESCRIPTION
4-24	PPO	1.5	63	TURBINE VALVE TEST
4-25	FMO	7.2	839	TURB.CONT.EH-ANALOG
5-22	PPO	1.3	89	TURBINE VALVE TEST
5-22	PFO	2.3	234	BACKPRESSURE CONTROL
5-23	PMO	4.4	244	WATERBOX CLEANING
6-10	PFO	4.1	109	#1 GOVERNOR VALVE
6-10	PMO	5.3	222	WATERBOX CLEANING
6-15	PMO	25.3	272	WATERBOX CLEANING
7-16	PFO	171.2	50	BACKPRESSURE CONTROL
7-23	PPO	1.3	85	TURBINE VALVE TEST
7-23	PMO	107.3	279	WATERBOX CLEANING
~~8- 1~~	~~PFO~~	~~71.3~~	~~839~~	~~HURRICANE ERIN~~
8- 4	FFO	14.1	839	GEN.SYNCH.EQUIP.
8-16	PFO	155.4	69	BACKPRESSURE CONTROL
8-23	PFO	5.0	198	HEATER DRAIN VALVE
8-23	PMO	31.8	386	WTRBX. CLNG.
8-25	PPO	7.5	97	TURBINE VALVE TEST
8-25	PFO	48.3	58	HEATER DRAIN PUMP
8-27	PFO	24.2	188	CIRC.WATER VALVE
8-28	PFO	7.3	106	HTR.DRN.PUMP PCM
9-11	PFO	66.5	75	BACKPRESSURE CONTROL
9-14	PMO	47.3	349	WATERBOX CLEANING
9-16	PPO	1.7	105	TURBINE VALVE TEST
9-25	PFO	126.8	118	BACKPRESSURE CONTROL

(1) FFO - FULL FORCED OUTAGE
PFO - PARTIAL FORCED OUTAGE
FMO - FULL MAINTENANCE OUTAGE
PMO - PARTIAL MAINTENANCE OUTAGE
PO - PLANNED OUTAGE
PPO - PARTIAL PLANNED OUTAGE

FILED:
SUSPENDED:
EFFECTIVE:
DOCKET NO.:
ORDER NO.:

ISSUED BY: FLORIDA POWER & LIGHT CO.

GENERATING PERFORMANCE INCENTIVE FACTOR

CALCULATION OF MAXIMUM ALLOWED INCENTIVE DOLLARS

ACTUAL

FLORIDA POWER & LIGHT COMPANY

PERIOD OF: APRIL 1995 THRU SEPTEMBER 1995

LINE 1	BEGINNING OF PERIOD BALANCE OF COMMON EQUITY END OF MONTH BALANCE OF COMMON EQUITY:		$ 4197244000
LINE 2	MONTH OF APRIL	95	$ 4215102000
LINE 3	MONTH OF MAY	95	$ 4231264000
LINE 4	MONTH OF JUNE	95	$ 4234180000
LINE 5	MONTH OF JULY	95	$ 4363578000
LINE 6	MONTH OF AUGUST	95	$ 4470114000
LINE 7	MONTH OF SEPTEMBER	95	$ 4438818000
LINE 8	AVERAGE COMMON EQUITY FOR THE PERIOD (SUMMATION OF LINE 1 THROUGH LINE 7 DIVIDED BY 7)		$ 4307185000
LINE 9	25 BASIS POINTS		0.0025
LINE 10	REVENUE EXPANSION FACTOR		60.4525%
LINE 11	MAXIMUM ALLOWED INCENTIVE DOLLARS (LINE 8 TIMES LINE 9 DIVIDED BY LINE 10 TIMES 0.5)		$ 8906128
LINE 12	JURISDICTIONAL SALES		40705736000 KWH
LINE 13	TOTAL SALES		41507892000 KWH
LINE 14	JURISDICTIONAL SEPARATION FACTOR (LINE 12 DIVIDED BY LINE 13)		98.07%
LINE 15	MAXIMUM ALLOWED JURISDICTIONAL INCENTIVE DOLLARS (LINE 11 TIMES LINE 14)		$ 8734239

GPIF UNIT PERFORMANCE SUMMARY

FLORIDA POWER & LIGHT COMPANY
PERIOD OF: APRIL 1995 THRU SEPTEMBER 1995

		WEIGHTING FACTOR (%)	TARGET (%)	EAF RANGE MAX. (%)	EAF RANGE MIN. (%)	MAX. FUEL SAVINGS ($000)	MAX. FUEL LOSS ($000)
CAPE CANAVERAL	1	0.48	91.2	94.2	88.2	60.2	64.1
CAPE CANAVERAL	2	0.48	89.8	92.8	86.8	60.2	64.1
LAUDERDALE	4	1.86	89.5	92.0	87.0	231.2	192.2
LAUDERDALE	5	1.60	95.7	97.7	93.7	199.4	182.4
FORT MYERS	2	0.53	91.7	94.7	88.7	65.6	55.7
MANATEE	2	0.32	96.0	98.0	94.0	40.4	43.5
PORT EVERGLADES	3	0.28	85.6	88.6	82.6	34.5	4.6
PORT EVERGLADES	4	0.42	96.0	98.0	94.0	52.5	40.5
PUTNAM	1	0.57	96.0	98.0	94.0	71.4	66.8
PUTNAM	2	0.61	84.2	86.7	81.7	75.3	64.4
RIVIERA	3	0.38	93.6	96.1	91.1	47.2	42.7
RIVIERA	4	0.40	90.9	93.9	87.9	50.1	57.6
SANFORD	5	0.32	96.0	98.0	94.0	39.8	17.5
TURKEY POINT	1	0.40	82.7	85.2	80.2	50.2	16.7
TURKEY POINT	2	0.10	95.6	97.6	93.6	12.1	20.7
TURKEY POINT	3	10.64	85.1	88.1	82.1	1323.8	1347.8
TURKEY POINT	4	12.01	93.1	96.1	90.1	1494.4	1490.9
ST. LUCIE	1	15.43	93.6	96.6	90.6	1919.6	1923.5
ST. LUCIE	2	12.36	83.3	87.8	78.8	1538.1	1548.3
SCHERER	4	0.48	96.0	98.0	94.0	59.2	85.0
		59.69				7425.2	7329.0

CV-1
DOCKET NO. 960001-EI
FPL WITNESS: CLAUDE VILLARD
EXHIBIT NO.______
JUNE 24, 1996

DOCUMENT NO.1
Thermal Uprate NPV Analysis

Year	Project Cost Recovery	Fuel Savings	Net Savings	NPV
1996				
1997	$5,000,000	$8,560,000	$3,560,000	$3,260,073
1998	$5,000,000	$10,150,000	$5,150,000	$4,318,789
1999		$10,510,000	$10,510,000	$8,071,139
2000		$10,320,000	$10,320,000	$7,257,535
2001		$11,600,000	$11,600,000	$7,470,416
2002		$12,320,000	$12,320,000	$7,265,657
2003		$12,240,000	$12,240,000	$6,610,327
2004		$12,660,000	$12,660,000	$6,261,128
2005		$14,130,000	$14,130,000	$6,399,388
2006		$13,310,000	$13,310,000	$5,520,160
2007		$15,160,000	$15,160,000	$5,757,715
2008		$15,670,000	$15,670,000	$5,450,010
2009		$16,080,000	$16,080,000	$5,121,436
2010		$17,030,000	$17,030,000	$4,967,041
2011		$18,580,000	$18,580,000	$4,962,564
	$10,000,000	$198,320,000	$188,320,000	$88,693,378

A discount rate of 9.2% was used to determine net present value.

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 960001-EI EXHIBIT NO 5
COMPANY/WITNESS: FPL/Villard
DATE: 5/29/96

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 960001-EI EXHIBIT NO 6
COMPANY/
WITNESS: FPL / Morley
DATE: 8/29/96

APPENDIX I

FUEL COST RECOVERY

TRUE-UP CALCULATION

BTB-1
DOCKET NO. 960001-EI
FPL WITNESS: B. T. BIRKETT
EXHIBIT ____
PAGES 1-4
May 20, 1996

APPENDIX I

FUEL COST RECOVERY CLAUSE

TABLE OF CONTENTS

FLORIDA POWER & LIGHT COMPANY
FUEL COST RECOVERY CLAUSE
SUMMARY OF NET TRUE-UP FOR THE
SIX MONTH PERIOD OCTOBER 1995 THROUGH MARCH 1996

1	End of Period True-up for the six month period October 1995 through March 1996 (from page 4, lines D7 & D8)	$ (81,698,246)
2	Less - Estimated/Actual True-up for the same period *	(64,536,189)
3	Decrease in underrecovery balance to reflect OBO revenues received in November 1995 through March 1996	5,005
4	Net True-up for the six month period October 1995 through March 1996	$ (17,157,052)

( ) Reflects Underrecovery

* Approved in FPSC Order No. PSC-96-0353-FOF-EI dated March 13, 1996

FLORIDA POWER & LIGHT COMPANY

FUEL COST RECOVERY CLAUSE

CALCULATION OF FINAL TRUE-UP VARIANCES

FOR THE PERIOD OCTOBER 1995 THROUGH MARCH 1996

LINE NO.				(1) ACTUAL	(2) UPDATED ESTIMATE (a)	(3) VARIANCE AMOUNT	(4) VARIANCE %
A	1	a	Fuel Cost of System Net Generation	$ 557,649,149	$ 500,697,518	$ 56,951,631	11.4 %
		b	Nuclear Fuel Disposal Costs	9,149,132	9,237,882	(88,750)	(1.0) %
		c	Coal Cars Depreciation & Return	2,552,532	2,552,532	(0)	0.0 %
		d	Gas Pipelines Depreciation & Return	1,892,178	1,892,184	(6)	0.0 %
		e	DOE Decontamination &Decommissioning Fund Payment	5,082,817	5,082,817	(0)	0.0 %
	2		Fuel Cost of Power Sold	(24,515,903)	(8,876,601)	(15,639,302)	176.2 %
	3	a	Fuel Cost of Purchased Power	64,839,761	68,172,314	(3,332,553)	(4.9) %
		b	Energy Payments to Qualifying Facilities	55,622,715	53,913,463	1,709,252	3.2 %
	4		Energy Cost of Economy Purchases	23,778,671	28,902,463	(5,123,792)	(17.7) %
	5		Total Fuel Costs & Net Power Transactions	$ 696,051,052	$ 661,574,572	$ 34,476,480	5.2 %
	6		Adjustments to Fuel Cost:				
		a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	$ (9,982,767)	$ (8,825,211)	$ (1,157,556)	13.1 %
		b	Inventory Adjustments	60,660	24,129	36,531	151.4 %
		c	Non-Recoverable Oil/Tank Bottoms	(200,145)	878	(201,023)	N/A
		d	Modifications to Generating Units	0	0	0	N/A
	7		Adjusted Total Fuel Costs & Net Power Transactions	$ 685,928,801	$ 652,774,367	$ 33,154,432	5.1 %
C	1		Jurisdictional kWh Sales	37,024,480,229	36,188,237,525	836,242,704	2.3 %
	2		Sale for Resale	224,246,338	167,655,273	56,591,065	33.8 %
	3		Total Sales (Excluding RTP Incremental)	37,248,726,567	36,355,892,798	892,833,769	2.5 %
	4		Jurisdictional Sales % of Total kWh Sales (Line B-6)	N/A	N/A	N/A	N/A
D	1		Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$ 644,420,662	$ 629,530,105	$ 14,890,557	2.4 %
		a	Prior Period True-up Provision	(38,399,209.02)	(38,399,209)	0	0.0 %
		b	Generation Performance Incentive Factor Net (b)	(3,041,235.48)	(3,041,235)	0	0.0 %
	3		Jurisdictional Fuel Revenues Applicable to Period	$ 602,980,218	$ 588,089,661	$ 14,890,557	2.5 %
	4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 685,928,800	$ 652,774,367	$ 33,154,433	5.1 %
		b	Nuclear Fuel Expense - 100% Retail	171,244	81,373	89,870	110.4 %
		c	RTP Incremental Fuel -100% Retail	98,070	26,404	71,665	271.4 %
		d	D&D Fund Payments -100% Retail (Line A 1 e)	5,082,817	5,082,817	(0)	0.0 %
		e	Adj. Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (D4a-D4b-D4c-D4d)	680,576,670	647,583,774	32,992,897	5.1 %
	6		Jurisdictional Total Fuel Costs & Net Power Transactions	$ 682,287,905	$ 650,269,086	$ 32,018,818	4.9 %
	7		True-up Provision for the Period- Over/(Under) Recovery (Line D3 - Line D6)	$ (79,307,687)	$ (62,179,426)	$ (17,128,261)	27.5 %
	8		Interest Provision for the Month	(2,390,559)	(2,356,763)	(33,796)	1.4 %
	9		True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(38,360,475)	(38,399,209)	38,734	(0.1) %
		a	Deferred True-up Beginning of Period - Over/(Under) Recovery	(33,181,566)	(33,181,566)	0	0.0 %
	10		Prior Period True-up Collected/(Refunded) This Period	38,399,209	38,399,209	0	0.0 %
	11		End of Period Net True-up Amount Over/(Under) Recovery (Lines D7 through D10)	$ (114,841,078)	$ (97,684,026)	$ (17,157,052)	17.6 %
					(c)		

(a) Per Estimated/Actual Schedule E-1b, filed January 22, 1996.

(b) GPIF reward of $3,090,162 / 6 Mos. x 98.4167% Revenue Tax Factor = $506,873.

(c) Total includes $33,729 reduction in Beg Underrecovery to reflect OBO Overrecovery at 9/30/95

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 960001-EI EXHIBIT NO 7
COMPANY/ WITNESS: FPL/Morley
DATE: 8/29/96

APPENDIX II

CAPACITY COST RECOVERY

TRUE-UP CALCULATION

BTB-2
DOCKET NO. 960001-EI
FPL WITNESS: B. T. BIRKETT
EXHIBIT ____
PAGES 1-6
May 20, 1996

APPENDIX II

CAPACITY COST RECOVERY CLAUSE

TABLE OF CONTENTS

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
SUMMARY OF NET TRUE-UP
FOR THE SIX MONTH PERIOD OCTOBER 1995 THROUGH MARCH 1996

1.	End-of-Period True-up for the Six Month Period October 1995 through March 1996 (From Page 6, Lines 14 + 15)	$67,886,374
2.	Less: Estimated/Actual True-up for the same period*	38,959,291
3.	Net True-up for the six month period October 1995 through March 1996	$28,927,083

( ) Reflects Underrecovery

* Approved in FPSC Order No. PSC-96-0353-FOF-EI dated March 13, 1996

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP AMOUNT
FOR THE PERIOD OCTOBER 1995 THROUGH MARCH 1996

	(1) ACTUAL OCTOBER	(2) ACTUAL NOVEMBER	(3) ACTUAL DECEMBER	(4) ACTUAL JANUARY	(5) ACTUAL FEBRUARY	(6) ACTUAL MARCH	(7) TOTAL
1. Unit Power (UPS) Capacity Charges	$6,511,777	$11,134,184	$11,181,186	$10,827,547	$9,381,613	$6,613,603	$55,649,910
2. SJRPP Capacity Charges	6,202,740	6,354,210	6,839,548	6,107,751	6,533,644	6,632,315	38,670,209
3. Qualifying Facilities (QF) Capacity Charges	13,236,921	12,311,678	16,701,035	23,138,508	23,481,133	23,070,791	111,940,067
4. Short-term Capacity Purchases	0	0	0	0	0	0	0
5. Revenues from Capacity Sales	(161,340)	(84,802)	(164,934)	(209,713)	(639,887)	(974,676)	(2,235,353)
6. Total Company Capacity Charges	25,790,099	29,715,270	34,556,835	39,864,093	38,756,503	35,342,033	204,024,833
7. Jurisdictional Separation Factor (a)	97.25530%	97.25530%	97.25530%	97.25530%	97.25530%	97.25530%	n/a
8. Jurisdictional Capacity Charges	25,082,238	28,899,675	33,608,353	38,769,943	37,692,754	34,372,000	198,424,963
9. Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(28,472,796)
10. Jurisdictional Capacity Charges Authorized for Recovery through CCR Clause	$20,336,772	$24,154,209	$28,862,887	$34,024,477	$32,947,288	$29,626,534	$169,952,167
11. Capacity Cost Recovery Revenues (Net of Revenue Taxes)	43,751,673	41,324,480	36,123,823	42,242,031	38,218,183	36,960,350	238,620,542
12. Prior Period True-up Provision	(435,982)	(435,982)	(435,982)	(435,981)	(435,981)	(435,981)	(2,615,889)
13. Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$43,315,691	$40,888,498	$35,687,841	$41,806,050	$37,782,202	$36,524,369	$236,004,653
14. True-up Provision for Month - Over/(Under) Recovery (Line 13 - Line 10)	22,978,919	16,734,289	6,824,954	7,781,573	4,834,914	6,897,835	66,052,486
15. Interest Provision for Month	159,989	257,023	317,359	344,056	361,014	394,447	1,833,888
16. True-up & Interest Provision Beginning of Month - Over/(Under) Recovery	(2,615,889)	20,959,002	38,386,295	45,964,590	54,526,201	60,168,110	(2,615,889)
17. Deferred True-up - Over/(Under) Recovery	23,587,130	23,587,130	23,587,130	23,587,130	23,587,130	23,587,130	23,587,130
18. Prior Period True-up Provision - Collected/(Refunded) this Month	435,982	435,982	435,982	435,981	435,981	435,981	2,615,889
19. End of Period True-up - Over/(Under) Recovery (Sum of Lines 14 through 18)	$44,546,132	$61,973,425	$69,551,720	$78,113,331	$83,745,240	$91,473,504	$91,473,504

Notes: (a) Per B. T. Birkett's Testimony Appendix IV, Page 3, Docket No. 950001-EI, filed June 20, 1995.
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, issued September 6, 1994, Docket No. 940001-EI, as adjusted in August 1993, per E. L. Hoffman's Testimony Appendix IV, Docket No. 930001-EI, filed July 8, 1993.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF INTEREST PROVISION
FOR THE PERIOD OCTOBER 1995 THROUGH MARCH 1996

	(1) ACTUAL OCTOBER	(2) ACTUAL NOVEMBER	(3) ACTUAL DECEMBER	(4) ACTUAL JANUARY	(5) ACTUAL FEBRUARY	(6) ACTUAL MARCH	(7) TOTAL
1. Beginning True-up Amount	$20,971,241	$44,546,132	$61,973,425	$69,551,720	$78,113,331	$83,745,240	n/a
2. Ending True-up Amount Before Interest	44,386,142	61,716,403	69,234,362	77,769,275	83,384,226	91,079,057	n/a
3. Total Beginning & Ending True-up Amount (Lines 1+2)	65,357,383	106,262,534	131,207,787	147,320,995	161,497,557	174,824,297	n/a
4. Average True-up Amount (50 % of Line 3)	$32,678,692	$53,131,267	$65,603,893	$73,660,498	$80,748,778	$87,412,149	n/a
5. Interest Rate - First day of Reporting Business Month	0.05940	0.05810	0.05800	0.05810	0.05400	0.05330	n/a
6. Interest Rate - First day of Subsequent Business Month	0.05810	0.05800	0.05810	0.05400	0.05330	0.05500	n/a
7. Total Interest Rate (Lines 5+6)	0.11750000	0.11610000	0.11610000	0.11210000	0.10730000	0.10830000	n/a
8. Average Interest Rate (50 % of Line 7)	0.05875000	0.05805000	0.05805000	0.05605000	0.05365000	0.05415000	n/a
9. Monthly Average Interest Rate (1/12 of Line 8)	0.00489583	0.00483750	0.00483750	0.00467083	0.00447083	0.00451250	n/a
10. Interest Provision for the Month (Line 4 X Line 9)	$159,989	$257,023	$317,359	$344,056	$361,014	$394,447	$1,833,888

NOTE: Columns and rows may not add due to rounding.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF FINAL TRUE-UP VARIANCES
FOR THE PERIOD OCTOBER 1995 THROUGH MARCH 1996

		(1) ACTUAL	(2) ESTIMATED/ ACTUAL (a)	(3) VARIANCE (1)-(2)	(4) PERCENTAGE CHANGE (3)/(2)
1.	Unit Power (UPS) Capacity Charges	$55,649,910	$62,592,905	($6,942,995)	-11.09%
2.	SJRPP Capacity Charges	38,670,209	$39,335,918	(665,709)	-1.69%
3.	Qualifying Facilities (QF) Capacity Charges	111,940,067	$114,983,297	(3,043,231)	-2.65%
4.	Short-term Capacity Purchases	0	$0	0	n/a
5.	Revenues from Capacity Sales	(2,235,353)	($930,987)	(1,304,365)	140.11%
6.	Total Company Capacity Charges	204,024,833	215,981,133	(11,956,300)	-5.54%
7.	Jurisdictional Separation Factor	97.25530%	97.25530%	0.00%	0.00%
8.	Jurisdictional Capacity Charges	198,424,963	210,053,099	(11,628,136)	-5.54%
9.	Capacity related amounts included in Base Rates (FPSC Portion Only)	(28,472,796)	(28,472,796)	0	0.00%
10.	Jurisdictional Capacity Charges Authorized for Recovery through CCR Clause	$169,952,167	$181,580,303	($11,628,136)	-6.40%
11.	Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$238,620,542	221,535,645	$17,084,896	7.71%
12.	Prior Period True-up Provision	(2,615,889)	(2,615,889)	0	n/a
13.	Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$236,004,653	$218,919,756	$17,084,896	7.80%
14.	True-up Provision - Over/(Under) Recovery (Line 13 - Line 10)	$66,052,486	$37,339,453	$28,713,033	n/a
15.	Interest Provision	1,833,888	1,619,838	214,050	n/a
16.	True-up & Interest Provision Begining of Month - Over/(Under) Recovery	(2,615,889)	(2,615,889)	0	0.00%
17.	Deferred True-up - Over/(Under) Recovery	23,587,130	23,587,130	0	n/a
18.	Prior Period True-up Provision - Collected/(Refunded)	2,615,889	2,615,889	0	0.00%
19.	End of Period True-up - Over/(Under) Recovery (Sum of Lines 14 through 18)	$91,473,504	$62,546,421	$28,927,083	n/a

Notes: (a) Per Appendix IV, Page 6, filed January 22, 1996, Docket 960001-EI, and approved at the February 1996 hearing, FPSC Order No.PSC-96-0353-FOF-EI.

APPENDIX III

CAPACITY COST RECOVERY

BTB - 4
DOCKET NO 960001-EI
FPL WITNESS:B.T.BIRKETT
EXHIBIT ___________
PAGES 1-8
JUNE 24, 1996

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 960001-EI EXHIBIT NO 9
COMPANY/ WITNESS: FPL / Morley
DATE: 8/29/96

APPENDIX III
CAPACITY COST RECOVERY

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FLORIDA POWER & LIGHT COMPANY
PROJECTED CAPACITY PAYMENTS
OCTOBER 1996 THROUGH SEPTEMBER 1997

		PROJECTED												
		OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	TOTAL
1	CAPACITY PAYMENTS TO NON-COGENERATORS	$17,390,315	$17,390,315	$17,390,315	$17,282,294	$17,282,294	$17,282,294	$17,282,294	$17,282,294	$17,282,294	$17,282,294	$17,282,294	$17,282,294	$207,711,591
2	CAPACITY PAYMENTS TO COGENERATORS	$26,674,718	$26,714,318	$26,714,318	$27,038,910	$27,038,910	$27,038,910	$27,076,818	$27,076,818	$27,090,238	$27,090,238	$27,090,238	$27,090,238	$323,734,672
3	CAPACITY PAYMENTS FOR MISSION SETTLEMENT	$730,728	$730,728	$730,728	$730,728	$730,728	$730,728	$730,728	$730,728	$730,728	$730,728	$730,728	$730,728	$8,768,730
4	REVENUES FROM CAPACITY SALES	$81,763	$154,682	$61,127	$53,542	$81,227	$219,451	$110,248	$183,477	$194,437	$466,348	$622,136	$371,717	$2,600,155
5	SYSTEM TOTAL (Lines 1+2+3-4)	$44,713,998	$44,680,679	$44,774,234	$44,998,390	$44,970,705	$44,832,481	$44,979,592	$44,906,363	$44,908,823	$44,636,912	$44,481,124	$44,731,543	$537,614,838
6	JURISDICTIONAL % *													97.33111%
7	JURISDICTIONALIZED CAPACITY PAYMENTS													$523,266,489
8	LESS: SJRPP CAPACITY PAYMENTS INCLUDED IN THE 1988 TAX SAVINGS REFUND DOCKET													($56,945,592)
9	FINAL TRUE-UP --overrecovery/(underrecovery) OCTOBER 1995 - MARCH 1996 $28,927,083	EST / ACT TRUE-UP --overrecovery/(underrecovery) APRIL 1996 - SEPTEMBER 1996 $13,378,068												$42,305,151
10	TOTAL (Lines 7+8-9)													$424,015,746
11	REVENUE TAX MULTIPLIER													1.01609
12	TOTAL RECOVERABLE CAPACITY PAYMENTS													$430,838,159

*CALCULATION OF JURISDICTIONAL %

	AVG. 12 CP AT GEN (MW)	%
FPSC	13,018	97.33111%
FERC	357	2.66889%
TOTAL	13,375	100.00000%

NOTE: BASED ON 1995 ACTUAL DATA

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF ENERGY & DEMAND ALLOCATION % BY RATE CLASS
OCTOBER 1996 THROUGH SEPTEMBER 1997

Rate Class	(1) AVG 12CP Load Factor at Meter (%)	(2) Projected Sales at Meter (kwh)	(3) Projected AVG 12 CP at Meter (kW)	(4) Demand Loss Expansion Factor	(5) Energy Loss Expansion Factor	(6) Projected Sales at Generation (kwh)	(7) Projected AVG 12 CP at Generation (kW)	(8) Percentage of Sales at Generation (%)	(9) Percentage of Demand at Generation (%)
RS1	60.910%	41,807,749,293	7,835,453	1.083175791	1.067486100	44,629,191,243	8,487,173	53.20547%	60.85589%
GS1	67.794%	4,918,750,249	828,246	1.083175791	1.067486100	5,250,697,520	897,136	6.25971%	6.43277%
GSD1	85.426%	17,893,046,568	2,391,058	1.083103456	1.067479781	19,100,465,432	2,589,763	22.77095%	18.56947%
OS2	93.911%	20,959,421	2,548	1.054413589	1.044406598	21,890,158	2,687	0.02610%	0.01927%
GSLD1/CS1	81.019%	7,270,483,651	1,024,407	1.081662033	1.067196356	7,759,033,872	1,108,062	9.25007%	7.94518%
GSLD2/CS2	82.073%	1,587,641,754	220,825	1.071305922	1.062656678	1,687,118,112	236,571	2.01133%	1.69629%
GSLD3/CS3	80.818%	758,060,128	107,076	1.029467667	1.024433539	776,582,220	110,231	0.92582%	0.79039%
ISST1D	193.881%	2,313,412	136	1.083175791	1.067486100	2,469,535	147	0.00294%	0.00105%
SST1T	48.948%	103,069,640	24,038	1.029467667	1.024433539	105,587,996	24,746	0.12588%	0.17744%
SST1D	146.426%	71,104,739	5,543	1.069724765	1.052872337	74,864,213	5,924	0.08925%	0.04248%
CILC D/CILC G	97.642%	2,528,505,648	295,613	1.075614838	1.063603766	2,689,328,130	317,966	3.20613%	2.27992%
CILC T	99.161%	1,119,271,028	128,852	1.029467667	1.024433539	1,146,618,760	132,649	1.36696%	0.95114%
MET	69.783%	86,779,954	14,196	1.054413589	1.044406598	90,633,557	14,968	0.10805%	0.10733%
OL1/SL1	585.192%	438,580,064	8,556	1.083175791	1.067486100	468,178,143	9,268	0.55815%	0.06645%
SL2	100.003%	73,231,231	8,359	1.083175791	1.067486100	78,173,321	9,054	0.09320%	0.06492%
TOTAL		78,679,547,000	12,894,906			83,880,832,232	13,946,345	100.00%	100.00%

(2) Projected kwh sales for the period October 1996 through September 1997
(3) Calculated: Col(2)/(8760 hours * Col(1))
(4) Based on 1995 demand losses.
(5) Based on 1995 energy losses.
(6) Col(2) * Col(5).
(7) Col(3) * Col(4).
(8) Col(6) / total for Col(6)
(9) Col(7) / total for Col(7)

FLORIDA POWER & LIGHT COMPANY
CALCULATION OF CAPACITY PAYMENT RECOVERY FACTOR
OCTOBER 1996 THROUGH SEPTEMBER 1997

Rate Class	(1) Percentage of Sales at Generation (%)	(2) Percentage of Demand at Generation (%)	(3) Energy Related Cost ($)	(4) Demand Related Cost ($)	(5) Total Capacity Costs ($)	(6) Projected Sales at Meter (kwh)	(7) Billing KW Load Factor (%)	(8) Projected Billed KW at Meter (kw)	(9) Capacity Recovery Factor ($/kw)	(10) Capacity Recovery Factor ($/kwh)
RS1	53.20547%	60.85589%	$17,633,036	$242,021,941	$259,654,977	41,807,749,293	-	-	-	0.00621
GS1	6.25971%	6.43277%	$2,074,555	$25,582,918	$27,657,473	4,918,750,249	-	-	-	0.00562
GSD1	22.77095%	18.56947%	$7,546,611	$73,850,181	$81,396,792	17,893,046,568	53.78184%	37,947,945	2.14	-
OS2	0.02610%	0.01927%	$8,650	$76,636	$85,286	20,959,421	-	-	-	0.00407
GSLD1/CS1	9.25007%	7.94518%	$3,065,602	$31,597,724	$34,663,326	7,270,483,851	61.64498%	16,158,331	2.15	-
GSLD2/CS2	2.01133%	1.69629%	$666,583	$6,746,090	$7,412,673	1,587,641,754	64.31296%	3,381,669	2.19	-
GSLD3/CS3	0.92582%	0.79039%	$306,830	$3,143,355	$3,450,185	758,060,128	64.60882%	1,607,271	2.15	-
ISST1D	0.00294%	0.00105%	$974	$4,176	$5,150	2,313,412	86.46049%	3,665	**	-
SST1T	0.12588%	0.17744%	$41,718	$705,673	$747,391	103,069,640	10.65279%	1,325,393	**	-
SST1D	0.08925%	0.04248%	$29,579	$168,942	$198,521	71,104,739	79.3601[illegible]%	122,705	**	-
CILC D/CILC G	3.20613%	2.27992%	$1,062,556	$9,067,168	$10,129,724	2,528,505,648	75.60946%	4,581,049	2.21	-
CILC T	1.36696%	0.95114%	$453,030	$3,782,653	$4,235,683	1,119,271,028	79.76567%	1,922,190	2.20	-
MET	0.10805%	0.10733%	$35,809	$426,848	$462,657	86,779,954	59.38085%	200,194	2.31	-
OL1/SL1	0.55815%	0.06645%	$184,979	$264,269	$449,248	438,580,084	-	-	-	0.00102
SL2	0.09320%	0.06492%	$30,888	$258,185	$289,073	73,231,231	-	-	-	0.00395
TOTAL			$33,141,400	$397,696,759	$430,838,159	78,679,547,000		67,248,412		

Note: There are currently no customers taking service on Schedule ISST1(T). Should any customer begin taking service on this schedule during the period, they will be billed using the ISST(D) Factor.

(1) Obtained from Document No. 2
(2) Obtained from Document No. 2
(3) (Total Capacity Costs/13) * Col (1)
(4) (Total Capacity Costs/13 * 12) * Col (2)
(5) Col (3) + Col (4)
(6) Projected kwh sales for the period October 1996 through September 1997
(7) (1995 kWh sales / 8760 hours)/((avg customer NCP)(8760 hours))
(8) Col (6) / ((7) *730) For GSD-1, only 83.265% of KW are billed due to 10 KW exemption
(9) Col (5) / (8)
(10) Col (5) / (6)

CAPACITY RECOVERY FACTORS FOR STANDBY RATES

Reservation Demand Charge (RDC) = (Total col 5)/(Doc 2, Total col 7)(.10) (Doc 2, col 4) / 12 months

Sum of Daily Demand Charge (SDD) = (Total col 5)/(Doc 2, Total col 7)/(21 onpeak days) (Doc 2, col 4) / 12 months

CAPACITY RECOVERY FACTOR

	RDC ** ($/kw)	SDD ** ($/kw)
ISST1 (D)	$0.28	$0.13
SST1 (T)	$0.27	$0.13
SST1 (D)	$0.28	$0.13

CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT
FOR THE PERIOD APRIL 1996 THROUGH SEPTEMBER 1996

	(1) ACTUAL APRIL	(2) ACTUAL MAY	(3) REVISED PROJECTIONS JUNE	(4) REVISED PROJECTIONS JULY	(5) REVISED PROJECTIONS AUGUST	(6) REVISED PROJECTIONS SEPTEMBER	(7) TOTAL
1. Unit Power (UPS) Capacity Charges	$3,874,296	$10,130,954	$10,824,720	$10,824,720	$10,824,720	$10,824,720	$57,304,130
2. SJRPP Capacity Charges	6,320,425	6,341,737	6,565,595	6,565,595	6,565,595	6,565,595	38,924,543
3. Qualifying Facilities (QF) Capacity Charges	23,646,489	22,981,858	26,674,718	26,674,718	26,674,718	26,674,718	153,327,219
4. Short-term Capacity Purchases	0	0	0	0	0	0	0
5. Revenues from Capacity Sales	(27,353)	(878,961)	(190,625)	(457,204)	(609,937)	(364,429)	(2,528,509)
6. Total Company Capacity Charges	33,813,858	38,575,588	43,874,408	43,607,829	43,455,096	43,700,604	247,027,383
7. Jurisdictional Separation Factor (a)	97.25530%	97.25530%	97.25530%	97.25530%	97.25530%	97.25530%	n/a
8. Jurisdictional Capacity Charges	32,885,769	37,516,804	42,670,187	42,410,925	42,262,384	42,501,154	240,247,223
9. Capacity related amounts included in Base Rates (FPSC Portion Only) (b)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(4,745,466)	(28,472,796)
10. Jurisdictional Capacity Charges Authorized for Recovery through CCR Clause	$28,140,303	$32,771,338	$37,924,721	$37,665,459	$37,516,918	$37,755,688	$211,774,427
11. Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$24,332,448	$24,452,663	$26,156,692	$28,914,103	$28,815,850	$28,063,637	$160,735,393
12. Prior Period True-up Provision	10,424,404	10,424,404	10,424,404	10,424,404	10,424,404	10,424,404	62,546,424
13. Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$34,756,852	$34,877,067	$36,581,096	$39,338,507	$39,240,254	$38,488,041	$223,281,817
14. True-up Provision for Month - Over/(Under) Recovery (Line 13 - Line 10)	$6,616,549	$2,105,729	($1,343,625)	$1,673,048	$1,723,336	$732,353	$11,507,390
15. Interest Provision for Month	406,795	377,609	334,113	289,448	251,483	211,230	1,870,678
16. True-up & Interest Provision Begining of Month - Over/(Under) Recovery	62,546,424	59,145,364	51,204,297	39,770,382	31,308,474	22,858,889	62,546,424
17. Deferred True-up - Over/(Under) Recovery	28,927,083	28,927,083	28,927,083	28,927,083	28,927,083	28,927,083	28,927,083
18. Prior Period True-up Provision - Collected/(Refunded) this Month	(10,424,404)	(10,424,404)	(10,424,404)	(10,424,404)	(10,424,404)	(10,424,404)	(62,546,424)
19. End of Period True-up - Over/(Under) Recovery (Sum of Lines 14 through 18)	$88,072,447	$80,131,380	$68,697,465	$60,235,557	$51,785,972	$42,305,151	$42,305,151

Notes: (a) Per B. T. Birkett's Testimony, Appendix IV, Page 3, Line 5, Docket No. 960001-EI, filed January 22, 1996.
(b) Per FPSC Order No. PSC-94-1092-FOF-EI, issued September 6, 1994 in Docket No. 940001-EI.

FLORIDA POWER & LIGHT COMPANY
CAPACITY COST RECOVERY CLAUSE
CALCULATION OF ESTIMATED/ACTUAL INTEREST PROVISION
FOR THE PERIOD APRIL 1996 THROUGH SEPTEMBER 1996

	(1) ACTUAL APRIL	(2) ACTUAL MAY	(3) REVISED PROJECTIONS JUNE	(4) REVISED PROJECTIONS JULY	(5) REVISED PROJECTIONS AUGUST	(6) REVISED PROJECTIONS SEPTEMBER	(7) TOTAL
1. Beginning True-up Amount	$91,473,507	$88,072,447	$80,131,380	$68,697,465	$60,235,557	$51,785,972	n/a
2. Ending True-up Amount Before Interest	87,665,652	79,753,771	68,363,351	59,946,109	51,534,489	42,093,921	n/a
3. Total Beginning & Ending True-up Amount (Lines 1 + 2)	179,139,159	167,826,218	148,494,732	128,643,573	111,770,046	93,879,893	n/a
4. Average True-up Amount (50 % of Line 3)	$89,569,579	$83,913,109	$74,247,366	$64,321,787	$55,885,023	$46,939,946	n/a
5. Interest Rate - First day of Reporting Business Month	0.05500	0.05400	0.05400	0.05400	0.05400	0.05400	n/a
6. Interest Rate - First day of Subsequent Business Month	0.05400	0.05400	0.05400	0.05400	0.05400	0.05400	n/a
7. Total Interest Rate (Lines 5 + 6)	0.10900000	0.10800000	0.10800000	0.10800000	0.10800000	0.10800000	n/a
8. Average Interest Rate (50 % of Line 7)	0.05450000	0.05400000	0.05400000	0.05400000	0.05400000	0.05400000	n/a
9. Monthly Average Interest Rate (1/12 of Line 8)	0.00454167	0.00450000	0.00450000	0.00450000	0.00450000	0.00450000	n/a
10. Interest Provision for the Month (Line 4 X Line 9)	$406,795	$377,609	$334,113	$289,448	$251,483	$211,230	$1,870,678

NOTE: Columns and rows may not add due to rounding.

FOR THE PERIOD APRIL 1996 THROUGH SEPTEMBER 1996

	(1) ESTIMATED/ ACTUAL	(2) ORIGINAL PROJECTIONS (a)	(3) VARIANCE (1)-(2)	(4) PERCENTAGE CHANGE (3)/(2)
1. Unit Power (UPS) Capacity Charges	$57,304,130	$67,658,640	($10,354,510)	-15.30%
2. SJRPP Capacity Charges	38,924,543	39,443,364	(518,821)	-1.32%
3. Qualifying Facilities (QF) Capacity Charges	153,327,219	150,874,748	2,452,471	1.63%
4. Short-term Capacity Purchases	0	0	0	n/a
5. Revenues from Capacity Sales	(2,528,509)	(1,910,161)	(618,348)	32.37%
6. Total Company Capacity Charges	247,027,383	256,066,591	(9,039,208)	-3.53%
7. Jurisdictional Separation Factor	97.25530%	97.25530%	0.00%	0.00%
8. Jurisdictional Capacity Charges	240,247,222	249,038,331	(8,791,109)	-3.53%
9. Capacity related amounts included in Base Rates (FPSC Portion Only)	(28,472,796)	(28,472,796)	0	0.00%
10. Jurisdictional Capacity Charges Authorized for Recovery through CCR Clause	$211,774,427	$220,565,535	($8,791,108)	-3.99%
11. Capacity Cost Recovery Revenues (Net of Revenue Taxes)	$160,735,393	$158,019,111	$2,716,282	1.72%
12. Prior Period True-up Provision	62,546,424	62,546,424	0	n/a
13. Capacity Cost Recovery Revenues Applicable to Current Period (Net of Revenue Taxes)	$223,281,817	$220,565,535	$2,716,282	1.23%
14. True-up Provision - Over/(Under) Recovery (Line 13 - Line 10)	$11,507,390	$0	$11,507,390	n/a
15. Interest Provision	1,870,678	0	1,870,678	n/a
16. True-up & Interest Provision Begining of Month - Over/(Under) Recovery	62,546,424	62,546,424	0	0.00%
17. Deferred True-up - Over/(Under) Recovery	28,927,083	0	28,927,083	n/a
18. Prior Period True-up Provision - Collected/(Refunded)	(62,546,424)	(62,546,424)	0	0.00%
19. End of Period True-up - Over/(Under) Recovery (Sum of Lines 14 through 18)	$42,305,151	$0	$42,305,151	n/a

Notes: (a) Per Appendix IV, page 3, filed January 22,1996, in Docket No. 960001-EI, and approved at the February 1996 hearings, FPSC Order No. PSC-96-0353-FOF-EI.

ATTACHMENT I
REVISED FUEL COST RECOVERY SCHEDULES

RM - 5
DOCKET NO 960001-EI
FPL WITNESS: R. MORLEY
EXHIBIT ___________
PAGES 1-11
AUGUST 20, 1996

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 960001-EI EXHIBIT NO 10
COMPANY/ WITNESS: FPL/Morley
DATE: 8/29/96

ATTACHMENT I

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June 1996 Fuel Variance

		$ MILLIONS	
	ACTUAL	ESTIMATE	$ VAR
1 Heavy Oil	$ 49.2	$ 26.3	$ 22.9
2 Coal	$ 8.6	$ 10.5	$ (1.9)
3 Gas	$ 63.7	$ 65.7	$ (2.0)
4 Nuclear	$ 5.5	$ 8.1	$ (2.6)
5 **Total Cost of Generation**	$ 127.1	$ 110.6	$ 16.5
6			
7 Fuel Cost of Power Sold	$ (3.0)	$ (1.7)	$ (1.4)
8 Fuel Cost of Purchased Power	$ 10.4	$ 12.6	$ (2.1)
9 Qualifying Facilities	$ 14.8	$ 9.9	$ 4.9
10 Economy Purchases	$ 4.9	$ 7.0	$ (2.0)
11 **Total Purchased Power Costs**	$ 27.1	$ 27.7	$ (0.7)
12			
13 Adjustments	$ 0.0	$ 1.0	$ (0.9)
14 **Total Fuel Costs**	$ 154.2	$ 139.3	$ 14.9
15			
16 **Jurisdictional Fuel Costs**	$ 153.5	$ 138.7	$ 14.8
17			
18 **Jurisdictional Fuel Revenues**	$ 121.7	$ 129.9	$ (8.1)
19			
20 Underrecovery	$ (31.8)	$ (8.8)	$ (22.9)
21 Interest	$ (0.7)	$ (0.7)	$ (0.0)
22 **Total Underrecovery**	$ (32.5)	$ (9.5)	$ (23.0)

July 1996 Fuel Variance

	$ MILLIONS		
	ACTUAL	ESTIMATE	$ VAR
1 Heavy Oil	$ 65.3	$ 44.4	$ 20.9
2 Coal	$ 10.3	$ 9.9	$ 0.4
3 Gas	$ 72.0	$ 62.5	$ 9.5
4 Nuclear	$ 6.1	$ 7.8	$ (1.7)
5 Total Cost of Generation	**$ 153.8**	**$ 124.6**	**$ 29.2**
6			
7 Fuel Cost of Power Sold	$ (2.4)	$ (9.2)	$ 6.7
8 Fuel Cost of Purchased Power	$ 18.4	$ 11.6	$ 6.8
9 Qualifying Facilities	$ 11.6	$ 11.0	$ 0.7
10 Economy Purchases	$ 6.1	$ 7.9	$ (1.8)
11 Total Cost of Purchased Power	**$ 33.7**	**$ 21.3**	**$ 12.4**
12			
13 Adjustments	$ 0.5	$ 1.0	$ (0.5)
14 Total Fuel Costs	**$ 188.0**	**$ 146.8**	**$ 41.2**
15			
16 Jurisdictional Fuel Costs	**$ 187.0**	**$ 146.2**	**$ 40.8**
17			
18 Jurisdictional Fuel Revenues	**$ 138.1**	**$ 145.3**	**$ (7.2)**
19			
20 Underrecovery	$ (48.9)	$ (0.9)	$ (48.0)
21 Interest	$ (0.8)	$ (0.6)	$ (0.2)
22 Underrecovery plus interest	$ (49.8)	$ (1.6)	$ (48.2)
23 July 1996 Unbilled Sales			$ 11.2
24 Total Underrecovery			**$ (37.0)**

SCHEDULE E1

FLORIDA POWER & LIGHT COMPANY

FUEL AND PURCHASED POWER
COST RECOVERY CLAUSE CALCULATION

ESTIMATED FOR THE PERIOD: OCTOBER 1996 - MARCH 1997

		(a)	(b)	(c)
		DOLLARS	MWH	¢/KWH
1	Fuel Cost of System Net Generation (E3)	$469,497,540	30,317,375	1.5486
2	Nuclear Fuel Disposal Costs (E2)	10,952,424	11,838,090	0.0925
3	Fuel Related Transactions (E2)	10,919,978	0	0.0000
4	Fuel Cost of Sales to FKEC / CKW	(9,852,205)	(457,194)	2.1549
5	TOTAL COST OF GENERATED POWER	$481,517,737	29,860,181	1.6126
6	Fuel Cost of Purchased Power (Exclusive of Economy) (E7)	61,297,950	3,970,720	1.5437
7	Energy Cost of Sched C & X Econ Purch (Broker) (E9)	26,724,990	1,481,431	1.8040
8	Energy Cost of Other Econ Purch (Non-Broker) (E9)	10,461,930	482,228	2.1695
9	Energy Cost of Sched E Economy Purch (E9)	0	0	0.0000
10	Capacity Cost of Sched E Economy Purchases	0	0	0.0000
11	Mission Settlement	5,220,180		
12	Payments to Qualifying Facilities (E8)	56,346,004	2,968,817	1.8979
13	TOTAL COST OF PURCHASED POWER	$160,051,054	8,903,196	1.7977
14	TOTAL AVAILABLE KWH (LINE 5 + LINE 12)		38,763,377	
15	Fuel Cost of Economy Sales (E6)	(8,163,695)	(301,734)	2.7056
16	Gain on Economy Sales (E6A)	(1,343,394)	(301,734)	0.4452
17	Fuel Cost of Unit Power Sales (SL2 Partpts) (E6)	(1,007,000)	(261,225)	0.3855
18	Fuel Cost of Other Power Sales (E6)	0	0	0.0000
19	TOTAL FUEL COST AND GAINS OF POWER SALES	($10,514,089)	(562,959)	1.8676
19a	Net Inadvertent Interchange	0	0	
20	TOTAL FUEL & NET POWER TRANSACTIONS (LINE 5 + 12 + 18 + 19)	$631,054,702	38,200,418	1.6520
21	Net Unbilled Sales	(21,171,129) **	(1,281,578)	(0.4688)
22	Company Use	1,893,164 **	114,601	0.0051
23	T & D Losses	41,018,556 **	2,483,027	0.1112
24	SYSTEM MWH SALES (Excl sales to FKEC / CKW)	$631,054,702	36,884,368	1.7109
25	Wholesale MWH Sales (Excl sales to FKEC / CKW)	$2,017,545	117,922	1.7109
26	Jurisdictional MWH Sales	$629,037,157	36,766,446	1.7109
27	Jurisdictional Loss Multiplier	-	-	1.00071
28	Jurisdictional MWH Sales Adjusted for Line Losses	$629,483,773	36,766,446	1.7121
29	FINAL TRUE-UP OCT 95 - MAR 96 $17,157,052 underrecovery; EST/ACT TRUE-UP APRIL 96 - SEPT 96 $149,035,547 underrecovery	166,192,598	36,766,446	0.4520
30	TOTAL JURISDICTIONAL FUEL COST	$795,676,371	36,766,446	2.1641
31	Revenue Tax Factor			1.01609
32	Fuel Factor Adjusted for Taxes			2.1989
33	GPIF *** reward	$1,947,105	36,766,446	0.0053
34	Fuel Factor including GPIF (Line 31 + Line 32)			2.2042
35	FUEL FACTOR ROUNDED TO NEAREST .001 CENTS/KWH			2.204

** For Informational Purposes Only
*** Calculation Based on Jurisdictional KWH Sales

SCHEDULE E - 1A

CALCULATION OF TOTAL TRUE-UP
(PROJECTED PERIOD)
FLORIDA POWER AND LIGHT COMPANY
FOR THE PERIOD: OCTOBER 1996 THROUGH MARCH 1997

1. Estimated over/(under) recovery (4 months actual, 2 months estimated period) (Schedule E1-B)	$ (149,035,547)
2. Final True-Up (6 months actual period)	$ (17,157,052)
3.Total over/(under) recovery (Lines 1 + 2) To be included in 6 month projected period (Schedule E1, Line 29)	$ (166,192,599)
2. TOTAL JURISDICTIONAL SALES (MWH) (Projected period)	36,766,446
3. True-Up Factor (Lines 3/4) c/kWh:	(0.4520)

LINE NO.		CALCULATION OF ESTIMATED/ACTUAL TRUE-UP AMOUNT COMPANY: FLORIDA POWER & LIGHT COMPANY FOR THE PERIOD APRIL THROUGH SEPTEMBER 1996 ACTUALS THROUGH JULY - REVISED ESTIMATES FOR AUGUST AND SEPTEMBER						SCHEDULE E-1b PAGE 1 of 1
			(1) ACTUAL APRIL	(2) ACTUAL MAY	(3) ACTUAL JUNE	(4) ACTUAL JULY	(5) ESTIMATED AUGUST	(6) ESTIMATED SEPTEMBER	(7) TOTAL PERIOD
A		Fuel Costs & Net Power Transactions							
1	a	Fuel Cost of System Net Generation	$ 96,121,431	$ 120,306,461	$ 127,149,539	$ 153,984,477	$ 128,230,970	$ 112,502,280	$ 738,295,159
	b	Nuclear Fuel Disposal Costs	1,729,346	1,373,659	1,270,144	1,335,141	1,893,273	1,893,273	9,494,835
	c	Coal Cars Depreciation & Return	418,841	416,961	415,081	413,201	411,320	409,440	2,484,843
	d	Gas Pipelines Depreciation & Return	309,871	308,302	306,733	305,164	303,595	302,026	1,835,691
	e	DOE D&D Fund Payment	0	0	0	0	0	0	0
2		Fuel Cost of Power Sold	(2,346,431)	(6,351,572)	(3,049,369)	(2,448,029)	(5,947,264)	(1,854,086)	(21,996,751)
3	a	Fuel Cost of Purchased Power	11,215,078	13,039,436	10,419,139	18,423,795	10,238,100	13,006,710	76,342,258
	b	Energy Payments to Qualifying Facilities	8,688,063	11,452,836	14,784,078	11,635,453	10,992,876	9,266,743	66,820,049
4		Energy Cost of Economy Purchases	3,852,915	3,643,369	4,940,055	6,095,589	9,982,330	9,712,240	38,226,498
5		Total Fuel Costs & Net Power Transactions	$ 119,989,114	$ 144,189,452	$ 156,235,400	$ 189,744,790	$ 156,105,200	$ 145,238,626	$ 911,502,582
6		Adjustments to Fuel Cost:							
	a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	(1,836,997)	(1,822,059)	$ (2,014,765)	$ (1,879,063)	$ (1,644,489)	$ (1,644,489)	$ (10,841,862)
	b	Inventory Adjustments	(6,000)	34,198	412	8,926	0	0	27,735
	c	Non Recoverable Oil/Tank Bottoms	133,725	(16,285)	0	120,478	0	0	227,918
	d	Modifications to Generating Units	0	0	0	0	0	0	0
7		Adjusted Total Fuel Costs & Net Power Transactions	$ 118,269,842	$ 142,375,306	$ 154,221,246	$ 187,995,131	$ 154,460,711	$ 143,594,137	$ 900,916,374
B		kWh Sales							
1		Jurisdictional kWh Sales (RTP @ CBL) (a)	5,425,135,569	5,928,331,567	6,790,726,130	7,192,072,906	7,450,237,000	7,255,755,000	40,042,258,172
2		Sale for Resale (excluding FKEC & CKW)	29,523,644	14,575,387	37,728,109	41,619,612	36,116,271	36,116,271	195,679,294
3		Sub-Total Sales (excluding FKEC & CKW)	5,454,659,213	5,942,906,954	6,828,454,239	7,233,692,518	7,486,353,271	7,291,871,271	40,237,937,466
6		Jurisdictional % of Total kWh Sales (lines B1/B3)	99.45874 %	99.75474 %	99.44749 %	99.42464 %	99.51757 %	99.50471 %	99.51369 %
C		True-up Calculation							
1		Jurisdictional Fuel Revenues (incl RTP @ CBL) Net of Revenue Taxes	$ 108,837,905	$ 120,749,205	$ 138,345,435	$ 154,746,863	$ 172,587,633	$ 157,170,651	$ 852,227,691
2		Fuel Adjustment Revenues Not Applicable to Period:							
	a	Prior Period True-up Provision	(16,280,671)	(16,280,671)	(16,280,671)	(16,280,671)	(16,280,671)	(16,280,671)	(97,684,026)
	b	GPIF, Net of Revenue Taxes (b)	(354,150)	(354,150)	(354,150)	(354,150)	(354,150)	(354,150)	(2,124,901)
	c	Oil Backout Revenues, Net of revenue Taxes	1,304	491	1,531	758			4,094
3		Jurisdictional Fuel Revenues Applicable to Period	$ 92,004,387	$ 104,114,875	$ 121,712,145	$ 138,112,800	$ 155,952,811	$ 140,535,829	$ 752,432,847
4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 118,269,842	$ 142,375,306	$ 154,221,246	$ 187,995,131	$ 154,460,711	$ 143,594,137	$ 900,916,374
	b	Nuclear Fuel Expense - 100% Retail	24,417	25,280	19,418	25,474	0	0	94,589
	c	RTP Incremental Fuel -100% Retail	17,836	(8,322)	49,364	9,812	0	0	68,689
	d	D&D Fund Payments -100% Retail	0	0	0	0	0	0	0
	e	Adj Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (C4a-C4b-C4c-C4d)	118,227,590	142,358,348	154,152,465	187,959,845	154,460,712	143,594,137	900,753,096
5		Jurisdictional Sales % of Total kWh Sales (Line B-6)	99.45874 %	99.75474 %	99.44749 %	99.42464 %	99.51757 %	99.50471 %	99.51369 %
6		Jurisdictional Total Fuel Costs & Net Power Transactions (Line C4e x C5 x 1.00070) +(Lines C4b,c,d)	$ 117,712,235	$ 142,125,585	$ 153,476,850	$ 187,044,500	$ 153,623,148	$ 142,983,948	$ 897,165,246
7		True-up Provision for the Month - Over/(Under) Recovery (Line C3 - Line C6)	$ (25,707,848)	$ (38,010,690)	$ (31,764,705)	$ (48,931,700)	$ 2,129,663	$ (2,447,119)	$ (144,732,399)
8		Interest Provision for the Month (Line D10)	(542,981)	(610,543)	(704,767)	(821,218)	(848,137)	(775,502)	(4,303,148)
9		True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(97,684,026)	(107,654,183)	(129,994,745)	(146,183,546)	(179,655,793)	(162,093,596)	(97,684,026)
	a	Deferred True-up Beginning of Period - Over/(Under) Recovery	(17,157,052)	(17,157,052)	(17,157,052)	(17,157,052)	(17,157,052)	(17,157,052)	(17,157,052)
10		Prior Period True-up Collected/(Refunded) This Period	16,280,671	16,280,671	16,280,671	16,280,671	16,280,671	16,280,671	97,684,026
11		End of Period Net True-up Amount Over/(Under) Recovery (Lines C7 through C10)	$ (124,811,235)	$ (147,151,797)	$ (163,340,598)	$ (196,812,845)	$ (179,250,648)	$ (166,192,598)	$ (166,192,598)

NOTES (a) Real Time Pricing (RTP) sales are shown at the Customer Base Load (CBL) KWH. The incremental/decremental kwh sales are excluded.

(b) Generation Performance Incentive Factor Reward (Per Order No. PSC-96-0353-FOF-EI) of $2,159,886 / 6 Mos. x 98.4167% Revenue Tax Factor = $354,150.

			FLORIDA POWER & LIGHT COMPANY				
			FUEL COST RECOVERY CLAUSE				
			CALCULATION OF ESTIMATED/ACTUAL VARIANCE				
			FOR THE PERIOD APRIL THROUGH SEPTEMBER 1996				
				(1)	(2)	(3)	(4)
LINE				ESTIMATED /	ORIGINAL	VARIANCE	
NO.				ACTUAL	PROJECTIONS (a)	AMOUNT	%
A	1	a	Fuel Cost of System Net Generation	$ 738,295,159	$ 564,837,790	$ 173,457,369	30.7 %
		b	Nuclear Fuel Disposal Costs	9,494,835	9,868,296	(373,461)	(3.8) %
		c	Coal Cars Depreciation & Return	2,484,843	2,593,692	(108,849)	(4.2) %
		d	Gas Pipelines Depreciation & Return	1,835,691	1,830,741	4,950	0.3 %
		e	DOE Decontamination &Decommissioning Fund Payment	0	0	0	N/A
	2		Fuel Cost of Power Sold	(21,996,751)	(18,849,433)	(3,147,318)	16.7 %
	3	a	Fuel Cost of Purchased Power	76,342,258	92,551,680	(16,209,422)	(17.5) %
		b	Energy Payments to Qualifying Facilities	66,520,049	56,153,965	10,666,084	19.0 %
	4		Energy Cost of Economy Purchases	38,226,498	37,880,270	346,228	0.9 %
	5		Total Fuel Costs & Net Power Transactions	$ 911,502,582	$ 746,867,001	$ 164,635,581	22.0 %
	6		Adjustments to Fuel Cost:				
		a	Sales to Fla Keys Elect Coop (FKEC) & City of Key West (CKW)	$ (10,841,861)	$ (10,059,440)	$ (782,421)	7.8 %
		b	Inventory Adjustments	27,735	0	27,735	N/A
		c	Non Recoverable Oil/Tank Bottoms	227,918	0	227,918	N/A
		d	Modifications to Generating Units	0	0	0	N/A
	7		Adjusted Total Fuel Costs & Net Power Transactions	$ 900,916,374	$ 736,807,561	$ 164,108,813	22.3 %
C	1		Jurisdictional kWh Sales	40,042,258,172	40,889,121,000	(846,862,828)	(2.1) %
	2		Sale for Resale	195,679,294	210,105,000	(14,425,706)	(6.9) %
	3		Total Sales (Excluding RTP Incremental)	40,237,937,466	41,099,226,000	(861,288,534)	(2.1) %
	4		Jurisdictional Sales % of Total kWh Sales (Line B-6)	N/A	N/A	N/A	N/A
D	1		Jurisdictional Fuel Revenues (Net of Revenue Taxes)	$ 852,237,691	$ 831,238,082	$ 20,999,609	2.5 %
		a	Prior Period True-up Provision	(97,684,026)	(97,684,026)	0	0.0 %
		b	Generation Performance Incentive Factor Net (b)	(2,124,901)	(2,124,901)	0	0.0 %
		c	Oil Backout Revenues, Net of revenue Taxes	4,084	0	4,084	N/A
	3		Jurisdictional Fuel Revenues Applicable to Period	$ 752,432,848	$ 731,429,155	$ 21,003,693	2.9 %
	4	a	Adjusted Total Fuel Costs & Net Power Transactions (Line A-7)	$ 900,916,374	$ 736,807,561	$ 164,108,813	22.3 %
		b	Nuclear Fuel Expense - 100% Retail	94,589	0	94,589	N/A
		c	RTP Incremental Fuel -100% Retail	68,689	0	68,689	N/A
		d	D&D Fund Payments -100% Retail (Line A 1 e)	0	0	0	N/A
		e	Adj. Total Fuel Costs & Net Power Transactions - Excluding 100% Retail Items (D4a-D4b-D4c-D4d)	900,753,096	736,807,561	163,945,535	22.3 %
	6		Jurisdictional Total Fuel Costs & Net Power Transactions	$ 897,165,246	$ 731,429,155	$ 165,736,091	22.7 %
	7		True-up Provision for the Period- Over/(Under) Recovery (Line D3 - Line D6)	$ (144,732,399)	$ (0)	$ (144,732,399)	N/A
	8		Interest Provision for the Month	(4,303,148)	-	(4,303,148)	N/A
	9		True-up & Interest Provision Beg. of Period - Over/(Under) Recovery	(97,684,026)	(97,684,026)	0	0.0 %
		a	Deferred True-up Beginning of Period - Over/(Under) Recovery	(17,157,052)	0	(17,157,052)	N/A
	10		Prior Period True-up Collected/(Refunded) This Period	97,684,026	97,684,026	0	0.0 %
	11		End of Period Net True-up Amount Over/(Under) Recovery (Lines D7 through D10)	$ (166,192,598)	$ (0)	$ (166,192,598)	N/A
			(a) Per Schedule E-2, filed January 22, 1996.				
			(b) Generation Performance Incentive Factor Reward (Per Order No. PSC-96-0353-FOF-EI)				
			of $2,159,086 / 6 Mos. x 98.4167% Revenue Tax Factor = $354,150.				

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1D

DETERMINATION OF FUEL RECOVERY FACTOR
TIME OF USE RATE SCHEDULES

OCTOBER 1996 - MARCH 1997

NET ENERGY FOR LOAD (%)		FUEL COST (%)
ON PEAK	28.00	30.20
OFF PEAK	72.00	69.80
	100.00	100.00

FUEL RECOVERY CALCULATION

		TOTAL	ON-PEAK	OFF-PEAK
1	TOTAL FUEL & NET POWER TRANS.	$631,054,702	$190,578,520	$440,476,182
2	MWH SALES	36,884,367	10,327,623	26,556,744
3	COST PER KWH SOLD	1.7109	1.8453	1.6586
4	JURISDICTIONAL LOSS FACTOR	1.00071	1.00071	1.00071
5	JURISDICTIONAL FUEL FACTOR	1.7121	1.8466	1.6598
6	TRUE-UP	0.4520	0.4520	0.4520
7				
8	TOTAL	2.1641	2.2986	2.1118
9	REVENUE TAX FACTOR	1.01609	1.01609	1.01609
10	RECOVERY FACTOR	2.1989	2.3356	2.1458
11	GPIF	0.0053	0.0053	0.0053
12	RECOVERY FACTOR including GPIF	2.2042	2.3409	2.1511
13	RECOVERY FACTOR ROUNDED TO NEAREST .001 c/KWH	2.204	2.341	2.151

HOURS:		
	ON-PEAK	23.30 %
	OFF-PEAK	76.70 %

FLORIDA POWER & LIGHT COMPANY

SCHEDULE E - 1E

FUEL RECOVERY FACTORS - BY RATE GROUP
(ADJUSTED FOR LINE/TRANSFORMATION LOSSES)

OCTOBER 1996 - MARCH 1997

(1) GROUP	(2) RATE SCHEDULE		(3) AVERAGE FACTOR	(4) FUEL RECOVERY LOSS MULTIPLIER	(5) FUEL RECOVERY FACTOR
A	RS-1, GS-1, SL-2		2.204	1.00201	2.209
A-1*	SL-1, OL-1		2.181	1.00201	2.185
B	GSD-1		2.204	1.00200	2.209
C	GSLD-1 & CS-1		2.204	1.00173	2.208
D	GSLD-2, CS-2, OS-2 & MET		2.204	0.99640	2.196
E	GSLD-3 & CS-3		2.204	0.96159	2.120
A	RST-1, GST-1	ON-PEAK	2.341	1.00201	2.346
		OFF-PEAK	2.151	1.00201	2.155
B	GSDT-1	ON-PEAK	2.341	1.00200	2.346
	CILC-1(G)	OFF-PEAK	2.151	1.00200	2.155
C	GSLDT-1 &	ON-PEAK	2.341	1.00173	2.345
	CST-1	OFF-PEAK	2.151	1.00173	2.155
D	GSLDT-2 &	ON-PEAK	2.341	0.99640	2.332
	CST-2	OFF-PEAK	2.151	0.99640	2.143
E	GSLDT-3, CST-3,	ON-PEAK	2.341	0.96159	2.251
	CILC -1(T) & ISST-1(T)	OFF-PEAK	2.151	0.96159	2.068
F	CILC -1(D) &	ON-PEAK	2.341	0.99814	2.337
	ISST-1(D)	OFF-PEAK	2.151	0.99814	2.147

* WEIGHTED AVERAGE 16% ON-PEAK AND 84% OFF-PEAK

COMPANY: FLORIDA POWER & LIGHT COMPANY

			DIFFERENCE	
	JULY 96 - SEPT 96	OCT 96 - MARCH 97	$	%
BASE	$47.46	$47.46	0.00	0.00%
FUEL	$22.05	$22.09	0.04	0.18%
CONSERVATION	$2.09	$2.09	0.00	0.00%
CAPACITY PAYMENT	$4.42	$6.21	1.79	40.50%
ENVIRONMENTAL	$0.15	$0.17	0.02	13.33%
SUBTOTAL	$76.17	$78.02	1.85	2.43%
GROSS RECEIPTS TAX	$0.78	$0.80	0.C2	2.56%
TOTAL	$76.95	$78.82	$1.87	2.43%

ATTACHMENT II
COMMISSION A3 SCHEDULES
JUNE AND JULY 1996

RM - 6
DOCKET NO 960001-EI
FPL WITNESS: R. MORLEY
EXHIBIT __________
PAGES
AUGUST 20, 1996

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 960001-EI EXHIBIT NO 11
COMPANY/WITNESS: FPL Morley
DATE: 8/29/96

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

MONTH OF: JUNE 1996

		CURRENT MONTH				PERIOD TO DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	* HEAVY OIL	49,237,772	26,301,880	22,935,892	87.2	104,601,270	81,665,378	22,935,892	28.1
2	* LIGHT OIL	63,656	12,450	51,206	NA	175,983	124,777	51,206	41.0
3	COAL	8,577,574	10,454,640	(1,877,066)	(18.0)	27,633,963	29,511,030	(1,877,067)	(6.4)
4	** GAS	63,740,887	65,741,820	(2,000,933)	(3.0)	190,673,588	192,674,521	(2,000,933)	(1.0)
5	NUCLEAR	5,529,651	8,124,390	(2,594,739)	(31.9)	20,492,627	23,087,366	(2,594,739)	(11.2)
6	ORIMULSION	0	0	0	0.0	0	0	0	0.0
7	TOTAL ($)	127,149,539	110,635,180	16,514,359	14.9	343,577,432	327,063,072	16,514,360	5.0
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	1,744,344	961,810	782,534	81.4	3,654,685	2,872,151	782,534	27.2
9	LIGHT OIL	948	199	749	NA	2,988	2,238	750	33.5
10	COAL	576,506	620,169	(43,663)	(7.0)	1,677,757	1,721,420	(43,663)	(2.5)
11	GAS	2,499,973	2,632,400	(132,427)	(5.0)	7,148,060	7,280,487	(132,427)	(1.8)
12	NUCLEAR	1,360,510	2,032,936	(672,426)	(33.1)	4,697,260	5,369,686	(672,426)	(12.5)
13	ORIMULSION	0	0	0	0.0	0	0	0	0.0
14	TOTAL (MWH)	6,182,281	6,247,514	(65,233)	(1.0)	17,180,750	17,245,982	(65,232)	(0.4)
	UNITS OF FUEL BURNED								
15	* HEAVY OIL (Bbl)	2,767,722	1,464,621	1,303,101	89.0	5,800,543	4,497,442	1,303,101	29.0
16	* LIGHT OIL (Bbl)	2,316	447	1,869	NA	6,439	4,570	1,869	40.9
17	*** COAL (TON)	66,489	66,966	(477)	(0.7)	180,118	180,595	(477)	(0.3)
18	** GAS (MCF)	22,328,581	22,909,646	(581,065)	(2.5)	62,979,556	63,560,621	(581,065)	(0.9)
19	NUCLEAR (MMBTU)	15,255,264	22,188,086	(6,932,822)	(31.2)	52,112,215	59,045,037	(6,932,822)	(11.7)
20	ORIMULSION (TON)	0	0	0	0.0	0	0	0	0.0
	BTU BURNED (MMBTU)								
21	HEAVY OIL	17,637,582	9,373,573	8,264,009	88.2	36,956,620	28,692,611	8,264,009	28.8
22	LIGHT OIL	13,501	2,608	10,893	NA	37,375	26,482	10,893	41.1
23	COAL	5,125,229	6,269,006	(1,143,777)	(18.2)	16,324,215	17,467,992	(1,143,777)	(6.5)
24	GAS	22,328,581	22,909,646	(581,065)	(2.5)	62,979,556	63,560,621	(581,065)	(0.9)
25	NUCLEAR	15,255,264	22,188,086	(6,932,822)	(31.2)	52,112,215	59,045,037	(6,932,822)	(11.7)
26	ORIMULSION	0	0	0	0.0	0	0	0	0.0
27	TOTAL (MMBTU)	60,360,157	60,742,919	(382,762)	(0.6)	168,409,981	168,792,743	(382,762)	(0.2)
	GENERATION MIX (%MWH)								
28	HEAVY OIL	28.22	15.40	12.82	83.2	21.27	16.65	4.62	27.7
29	LIGHT OIL	0.02	0.00	0.02	NA	0.02	0.01	0.01	100.0
30	COAL	9.33	9.93	(0.60)	(6.0)	9.77	9.98	(0.21)	(2.1)
31	GAS	40.44	42.14	(1.70)	(4.0)	41.61	42.22	(0.61)	(1.4)
32	NUCLEAR	22.01	32.54	(10.53)	(32.4)	27.34	31.14	(3.80)	(12.2)
33	ORIMULSION	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
34	TOTAL (%)	100.00	100.00	0.00	0.0	100.00	100.00	0.00	0.0
	FUEL COST PER UNIT								
35	* HEAVY OIL ($/Bbl)	17.7900	17.9581	(0.1681)	(0.9)	18.0330	18.1582	(0.1252)	(0.7)
36	* LIGHT OIL ($/Bbl)	27.4853	27.8523	(0.3670)	(1.3)	27.3308	27.3035	0.0273	0.1
37	*** COAL ($/TON)	40.8582	40.0858	0.7724	1.9	42.0050	41.7156	0.2894	0.7
38	** GAS ($/MCF)	2.8547	2.8696	(0.0149)	(0.5)	3.0275	3.0314	(0.0039)	(0.1)
39	NUCLEAR ($/MMBTU)	0.3625	0.3662	(0.0037)	(1.0)	0.3932	0.3910	0.0022	0.6
40	ORIMULSION ($/TON)	0.0000	0.0000	0.0000	0.0	0.0000	0.0000	0.0000	0.0
	FUEL COST PER MMBTU ($/MMBTU)								
41	* HEAVY OIL	2.7916	2.8060	(0.0144)	(0.5)	2.8304	2.8462	(0.0158)	(0.6)
42	* LIGHT OIL	4.7149	4.7738	(0.0589)	(1.2)	4.7086	4.7118	(0.0032)	(0.1)
43	COAL	1.6736	1.6677	0.0059	0.4	1.6928	1.6894	0.0034	0.2
44	** GAS	2.8547	2.8696	(0.0149)	(0.5)	3.0275	3.0314	(0.0039)	(0.1)
45	NUCLEAR	0.3625	0.3662	(0.0037)	(1.0)	0.3932	0.3910	0.0022	0.6
46	ORIMULSION	0.0000	0.0000	0.0000	0.0	0.0000	0.0000	0.0000	0.0
47	TOTAL ($/MMBTU)	2.1065	1.8214	0.2851	15.7	2.0401	1.9377	0.1024	5.3
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	10,111	9,746	365	3.7	10,112	9,990	122	1.2
49	LIGHT OIL	14,236	13,106	1,130	8.6	12,509	11,833	676	5.7
50	COAL	8,890	10,109	(1,219)	(12.1)	9,730	10,147	(417)	(4.1)
51	GAS	8,932	8,703	229	2.6	8,811	8,730	81	0.9
52	NUCLEAR	11,213	10,914	299	2.7	11,094	10,996	98	0.9
53	ORIMULSION	0	0	0	0.0	0	0	0	0.0
54	TOTAL (BTU/KWH)	9,763	9,723	40	0.4	9,802	9,787	15	0.2
	GENERATED FUEL COST PER KWH (¢/KWH)								
55	* HEAVY OIL	2.8227	2.7346	0.0881	3.2	2.8621	2.8434	0.0187	0.7
56	* LIGHT OIL	6.7119	6.2563	0.4556	7.3	5.8902	5.5754	0.3148	5.6
57	COAL	1.4879	1.6858	(0.1979)	(11.7)	1.6471	1.7143	(0.0672)	(3.9)
58	** GAS	2.5497	2.4974	0.0523	2.1	2.6675	2.6465	0.0210	0.8
59	NUCLEAR	0.4064	0.3996	0.0068	1.7	0.4363	0.4300	0.0063	1.5
60	ORIMULSION	0.0000	0.0000	0.0000	0.0	0.0000	0.0000	0.0000	0.0
61	TOTAL (¢/KWH)	2.0567	1.7709	0.2858	16.1	1.9998	1.8965	0.1033	5.4

* Distillate & Propane (Bbls & $) used for firing, hot standby, ignition, prewarming, etc. in Fossil Steam Plants is included in Heavy Oil and Light Oil. Values may not agree with Schedule A5

** Includes gas used for Fossil Steam Plants start-up. Estimated values may not agree with Schedule A5

*** Scherer coal is reported in MMBTU's only. Scherer coal is not included in TONS

COMPANY: FLORIDA POWER & LIGHT COMPANY

SCHEDULE A3

GENERATING SYSTEM COMPARATIVE DATA BY FUEL TYPE

MONTH OF: JULY 1996

		CURRENT MONTH				PERIOD TO DATE			
				DIFFERENCE				DIFFERENCE	
		ACTUAL	ESTIMATED	AMOUNT	%	ACTUAL	ESTIMATED	AMOUNT	%
	FUEL COST OF SYSTEM NET GENERATION ($)								
1	* HEAVY OIL	65,327,352	44,392,820	20,934,532	47.2	169,928,622	126,058,198	43,870,424	34.8
2	* LIGHT OIL	211,585	79,800	131,785	165.1	387,568	204,577	182,991	89.4
3	COAL	10,347,889	9,932,920	414,969	4.2	37,981,853	39,443,950	(1,462,097)	(3.7)
4	** GAS	72,034,862	62,495,240	9,539,622	15.3	262,708,450	255,169,761	7,538,689	3.0
5	NUCLEAR	6,062,789	7,770,780	(1,707,991)	(22.0)	26,555,416	30,858,146	(4,302,730)	(13.9)
6	ORIMULSION	0	0	0	0.0	0	0	0	0.0
7	TOTAL ($)	153,984,477	124,671,560	29,312,917	23.5	497,561,909	451,734,632	45,827,277	10.1
	SYSTEM NET GENERATION (MWH)								
8	HEAVY OIL	2,397,964	1,682,418	715,546	42.5	6,052,649	4,554,569	1,498,080	32.9
9	LIGHT OIL	2,355	1,279	1,076	84.2	5,343	3,517	1,826	51.9
10	COAL	596,073	589,467	6,606	1.1	2,273,830	2,310,887	(37,057)	(1.6)
11	GAS	2,321,898	2,462,188	(140,290)	(5.7)	9,469,958	9,742,675	(272,717)	(2.8)
12	NUCLEAR	1,433,690	1,967,358	(533,668)	(27.1)	6,130,950	7,337,044	(1,206,094)	(16.4)
13	ORIMULSION	0	0	0	0.0	0	0	0	0.0
14	TOTAL (MWH)	6,751,980	6,702,710	49,270	0.7	23,932,730	23,948,692	(15,962)	(0.1)
	UNITS OF FUEL BURNED								
15	* HEAVY OIL (Bbl)	3,792,890	2,537,034	1,255,856	49.5	9,593,433	7,034,476	2,558,957	36.4
16	* LIGHT OIL (Bbl)	7,553	2,868	4,685	163.4	13,992	7,438	6,554	88.1
17	*** COAL (TON)	72,261	64,496	7,765	12.0	252,379	245,091	7,288	3.0
18	** GAS (MCF)	21,053,751	21,417,226	(363,475)	(1.7)	84,033,307	84,977,847	(944,540)	(1.1)
19	NUCLEAR (MMBTU)	16,112,388	21,472,340	(5,359,952)	(25.0)	68,224,603	80,517,377	(12,292,774)	(15.3)
20	ORIMULSION (TON)	0	0	0	0.0	0	0	0	0.0
	BTU BURNED (MMBTU)								
21	HEAVY OIL	24,046,140	16,237,015	7,809,125	48.1	61,002,760	44,929,626	16,073,134	35.8
22	LIGHT OIL	43,604	16,718	26,886	160.8	80,979	43,200	37,779	87.5
23	COAL	5,923,292	5,956,676	(33,384)	(0.6)	22,247,507	23,424,668	(1,177,161)	(5.0)
24	GAS	21,053,751	21,417,226	(363,475)	(1.7)	84,033,307	84,977,847	(944,540)	(1.1)
25	NUCLEAR	16,112,388	21,472,340	(5,359,952)	(25.0)	68,224,603	80,517,377	(12,292,774)	(15.3)
26	ORIMULSION	0	0	0	0.0	0	0	0	0.0
27	TOTAL (MMBTU)	67,179,175	65,099,975	2,079,200	3.2	235,589,156	233,892,718	1,696,438	0.7
	GENERATION MIX (%MWH)								
28	HEAVY OIL	35.51	25.10	10.41	41.5	25.29	19.02	6.27	33.0
29	LIGHT OIL	0.03	0.02	0.01	50.0	0.02	0.01	0.01	100.0
30	COAL	8.83	8.79	0.04	0.5	9.50	9.65	(0.15)	(1.6)
31	GAS	34.39	36.73	(2.34)	(6.4)	39.57	40.68	(1.11)	(2.7)
32	NUCLEAR	21.23	29.35	(8.12)	(27.7)	25.62	30.64	(5.02)	(16.4)
33	ORIMULSION	0.00	0.00	0.00	0.0	0.00	0.00	0.00	0.0
34	TOTAL (%)	100.00	100.00	0.00	0.0	100.00	100.00	0.00	0.0
	FUEL COST PER UNIT								
35	* HEAVY OIL ($/Bbl)	17.2236	17.4979	(0.2743)	(1.6)	17.7130	17.9201	(0.2071)	(1.2)
36	* LIGHT OIL ($/Bbl)	28.0134	27.8243	0.1891	0.7	27.6993	27.5043	0.1950	0.7
37	*** COAL ($/TON)	41.6015	39.9046	1.6969	4.3	41.8895	41.2390	0.6505	1.6
38	** GAS ($/MCF)	3.4215	2.9180	0.5035	17.3	3.1262	3.0028	0.1234	4.1
39	NUCLEAR ($/MMBTU)	0.3763	0.3619	0.0144	4.0	0.3892	0.3832	0.0060	1.6
40	ORIMULSION ($/TON)	0.0000	0.0000	0.0000	0.0	0.0000	0.0000	0.0000	0.0
	FUEL COST PER MMBTU ($/MMBTU)								
41	* HEAVY OIL	2.7168	2.7341	(0.0173)	(0.6)	2.7856	2.8057	(0.0201)	(0.7)
42	* LIGHT OIL	4.8524	4.7733	0.0791	1.7	4.7860	4.7356	0.0504	1.1
43	COAL	1.7470	1.6675	0.0795	4.8	1.7072	1.6839	0.0233	1.4
44	** GAS	3.4215	2.9180	0.5035	17.3	3.1262	3.0028	0.1234	4.1
45	NUCLEAR	0.3763	0.3619	0.0144	4.0	0.3892	0.3832	0.0060	1.6
46	ORIMULSION	0.0000	0.0000	0.0000	0.0	0.0000	0.0000	0.0000	0.0
47	TOTAL ($/MMBTU)	2.2921	1.9151	0.3770	19.7	2.1120	1.9314	0.1806	9.4
	BTU BURNED PER KWH (BTU/KWH)								
48	HEAVY OIL	10,028	9,651	377	3.9	10,079	9,865	214	2.2
49	LIGHT OIL	18,512	13,071	5,441	41.6	15,156	12,283	2,873	23.4
50	COAL	9,937	10,105	(168)	(1.7)	9,784	10,137	(353)	(3.5)
51	GAS	9,067	8,698	369	4.2	8,874	8,722	152	1.7
52	NUCLEAR	11,238	10,914	324	3.0	11,128	10,974	154	1.4
53	ORIMULSION	0	0	0	0.0	0	0	0	0.0
54	TOTAL (BTU/KWH)	9,950	9,712	238	2.5	9,844	9,766	78	0.8
	GENERATED FUEL COST PER KWH (¢/KWH)								
55	* HEAVY OIL	2.7243	2.6386	0.0857	3.2	2.8075	2.7677	0.0398	1.4
56	* LIGHT OIL	8.9839	6.2392	2.7437	44.0	7.2536	5.8168	1.4368	24.7
57	COAL	1.7360	1.6851	0.0509	3.0	1.6704	1.7069	(0.0365)	(2.1)
58	** GAS	3.1024	2.5382	0.5642	22.2	2.7741	2.6191	0.1550	5.9
59	NUCLEAR	0.4229	0.3950	0.0279	7.1	0.4331	0.4206	0.0125	3.0
60	ORIMULSION	0.0000	0.0000	0.0000	0.0	0.0000	0.0000	0.0000	0.0
61	TOTAL (¢/KWH)	2.2806	1.8600	0.4206	22.6	2.0790	1.8863	0.1927	10.2

* Distillate & Propane (Bbls & $) used for firing, hot standby, ignition, prewarming, etc. in Fossil Steam Plants is included in Heavy Oil and Light Oil. Values may not agree with Schedule A5

** Includes gas used for Fossil Steam Plants start-up. Estimated values may not agree with Schedule A5.

*** Scherer coal is reported in MMBTU's only. Scherer coal is not included in TONS

CERTIFICATE OF SERVICE
DOCKET NO. 960001-EI

I HEREBY CERTIFY that a true and correct copy of Florida Power & Light Company's Supplemental Testimony of Rosemary Morely has been furnished by Hand Delivery,** or U.S. Mail this 20th day of August, 1996, to the following:

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DOCUMENT NO. 1
FLORIDA POWER AND LIGHT COMPANY
RESPONSES TO STAFF'S THIRD SET OF INTERROGATORIES
NOS. 15, 16, 17, 18, 20, AND 21

RLW-1
DOCKET NO. 960001-EI
FPL WITNESS: R. L. WADE
EXHIBIT________
PAGES 1 - 25
JUNE 24, 1996

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET
NO. 960001-EI EXHIBIT NO 12
COMPANY/
WITNESS: FPL/Wade
DATE: 8/25/96

15. Q. On what date and at what time(s) were the St. Lucie nuclear units taken off line due to Hurricane Erin?

A. St. Lucie Unit 1 was taken off line on August 1, 1995 at 14:55 hours. St. Lucie Unit 2 was taken off line on August 1, 1995 at 11:28 hours.

16. Q. Were these times based on procedures prescribed by a regulatory agency? If yes, please identify the regulatory agency.

A. The times were based on FPL procedures developed to comply with the Nuclear Regulatory Commission's (NRC) Station Blackout Rule as specified in Chapter 10, Part 50.63 of the Code of Federal Regulations (CFR).

The Station Blackout Rule was developed to provide assurance that nuclear plants have sufficient equipment and procedural guidance to safely maintain critical plant functions during time periods when they may not be able to generate electricity concurrent with periods when the availability of off site power is questionable.

In complying with the requirements of the Station Blackout Rule, FPL committed to the NRC to commence the shutdown of the St. Lucie units prior to the projected onset of hurricane force winds.

17. Q. When the St. Lucie nuclear units are taken off line due to a threatening hurricane, what length of time is required to return the units to service?

A. The length of time to return a unit to service after the passing of a hurricane varies depending on the amount of damage incurred and the outcome of key start up activities. After the passage of a Hurricane, site damage assessment as well as two primary start up areas must be addressed. One area is the Site Emergency Plan and the second is normal plant start up operations.

The first step in unit start up involves plant damage assessment to determine the extent of plant damage and required repairs, if repairs are required, to ensure safe operations of plant. In addition to damage assessment, St. Lucie is required by their Technical Specifications to maintain an emergency plan. The plan requires several activities be completed prior to unit start up. Emergency plan activities include:

1. Equipment defined in the technical specifications has been returned to service. This includes both plant equipment as well as off site equipment such as the public warning sirens.
2. The equipment and processes defined in the plant Radiological Emergency Plan have been assessed and found to be acceptable.

In addition to the responsibilities of FPL, the State of Florida Radiological Emergency Management Plan for nuclear power plants specifies actions for local governments in support of plant operations. These agencies include the State Division of Emergency Management, the department of Health and Rehabilitative Services, Office of Radiation Control and all risk counties (those counties within ten miles of the plant).

State and local government must be able to adequately implement their radiological emergency plans following a storm. Activities performed at the State and local government level include:

1. Ensure the Emergency Broadcast System is available.
2. Adequate shelter capacity and support exists.
3. Adequate manpower is available.
4. Adequate transportation is available for those with special needs.

In addition to activities required under the Emergency Plan, the plant must follow normal plant start up procedures.

Plant start up from cold shut down involves numerous activities. The unit goes through a series of modes (Mode Five to Mode One) until the unit is placed back in service. A summary of the key start up activities include:

1. RCS is heated and pressure maintained via the pressurizer heaters and reactor coolant pumps.
2. Mode Four is reached when RCS temperature reaches 200F.
3. Unit enters Mode Three once RCS temperature reaches 325F. This mode is called hot standby.
4. From Mode Three to Mode One involves reactor start up. Once the desired operating temperature is reached, the control rods are withdrawn from the core and the reactor becomes critical.
5. Turbine start up is initiated. Steam lines are warmed and vacuum is established in the condensers.
6. Main generator start up is initiated.

As reactor power is slowly increased numerous tests are performed. The unit is brought up to full power through a series of hold points until 100% power is reached.

During the entire start up process, numerous tests are conducted on auxiliary and safety systems to ensure normal operation. These tests may identify components which require corrective actions be performed. These actions may affect the time required to return the unit to service.

18. Q. Did Hurricane Erin cause any damage to either of the St. Lucie nuclear units?

A. No.

20. Q. Please provide the names, titles and company affiliation of each member of the outside team of utility experts that recently assessed the performance of Florida Power and Light Company's St. Lucie nuclear power plants.

A. R.J. Hovey, Assistant Site Vice President Turkey Point Nuclear Plant, Florida Power and Light Co.

R.K. Edington, Plant Manager Arkansas Nuclear One, Entergy Operations, Inc.

W.R. Matthews, Assistant Station Manager North Anne Power Station, Virginia Electric and Power Company.

J.T. Voorhees, Quality Assurance Supervisor St. Lucie Nuclear Plant, Florida Power and Light Co.

The team was formed of three off site managers, two from outside FPL and one from the Turkey Point Nuclear Station, and one on site employee. This composition provided familiarity with St. Lucie plant personnel and procedures coupled with the independence of non FPL expertise.

21. Q. Please provide a detailed description of each incident occurring from September, 1994, to the current date at the St. Lucie plant that affected the operation of either nuclear unit. The description should include, but not limited to the following:

a. the cause of the incident
b. the corrective action steps taken by the company:
   i. person/company correcting the problem
   ii. cost to correct the problem (parts and labor)
   iii. environmental impacts
c. a timeline that indicates when each corrective action step was completed
d. source of replacement energy
e. total KWH's purchased/generated of replacement energy
f. total cost of replacement energy
g. fuel cost of replacement energy

A. a,b,c. See pages 3 through 19 of this response (pages numbers corresponding to each event are provided in the table below)

d. During each incident that affected the operation of the St. Lucie plant, FPL's source of replacement energy was from FPL system resources. Since the replacement energy came from FPL's system output, it cannot be specifically tied to any particular FPL generating unit.

e, f, g. See table below

ST LUCIE UNIT NO.	DATE	EVENT	For (a) (b) (c) See Page	(e) REPLACEMENT ENERGY kWh	(f) & (g) COST (see notes 1,2 & 3 below)
1	Oct 26-94	Potential Transformer	3	7,210	$120,835
1	Feb 27-95	Quench Tank In Leakage	4	163,667,000	$2,264,639
1	Jul 8-95	Turbine Trip During Surveillance Testing	5	36,050,000	$615,742
1	Jul 10-95	External Event, Vehicle in Discharge Canal	6	25,235,000	$417,900
1 and 2	Aug 1-95	External Event, Hurricane Erin	7	68,571,000	$1,054,361
1	Aug 2-95	1A2 Reactor Coolant Pump Seal Package Failure	8	124,012,000	$2,123,006
1	Aug 9-95	Power Operated Relief Valve Failures	9-10	134,883,000	$2,577,776

ST LUCIE UNIT NO.	DATE	EVENT	For (a) (b) (c) See Page	(e) REPLACEMENT ENERGY kWh	(f) & (g) COST (see notes 1,2 & 3 below)
1	Aug 17-95	Inadvertent Spray Down of Containment	11	248,024,000	$4,179,840
1	Sep 1-95	1B2 EDG Rocker Arm Adjusting Screw Lock Nut	12	166,739,000	$2,844,879
1	Sep 11-95	Pressurizer Code Safety Valve Flange Leakage	13	124,733,000	$2,086,873
1	Sep 19-95	1B Emergency Diesel Generator Hold Down Bolts	14	51,191,000	$824,809
1	Sep 22-95	1A & 1B EDG Governor Stability	15	46,307,000	$748,007
1	Sep 24-95	Pressurizer Code Safety Valve Alignment Modifications	16	325,892,000	$5,208,977
2	Feb 21-95	Steam Generator Level Transmitter Failure	17	53,678,000	$637,288
2	Apr 25-95	Digital Electro-Hydraulic Power Supply Failure	18	5,456,000	$70,814
2	Aug 4-95	Switchyard Circuit Breaker Failure	19	9,548,000	$186,098

Assumptions:

1) Total KWH replacement energy based upon net to FPL from: a) PSL1 of 776MW per hour less projected forced outage rate and projected maintenance outage rate of 3.1% and 4%, respectively and b) PSL2 of 777 megawatts per hour less projected forced outage rate and projected maintenance outage rate of 9.9% and 2.3%, respectively. The projected outage rates are taken from the Fuel Cost Recovery filing of June 1995. The resultant output (721 and 682 for PSL#1 and PSL#2) was considered the energy to be replaced for each hour the unit was off-line.

2) Total Cost and Fuel Cost are equal since there was no capacity purchased to replace PSL output

3) The replacement fuel cost based upon the FPL hourly system lambda (cost of next megawatt) adjusted for the decremental block of energy assumed in assumption 1 above. The average cost of PSL energy ($per megawatt hour) was assumed to be $5.58 and $6.75 for PSL#1 and PSL#2 respectively. The PSL cost was subtracted from the adjusted FPL hourly system lambda and was multiplied by the replacement energy.

Event: Potential Transformer

St. Lucie Unit 1

Event date: October 26, 1994

On October 26, 1994, Unit 1 was in Mode 1 and operating at 100% power. At 2:26 P.M., an arc was observed in the area of the 240 KV switchyard near the Unit 1 synchronizing potential transformer. Concurrently, Unit 1 experienced an automatic reactor trip on loss of electrical load predicated by main generator differential current condition. Standard post trip actions were performed, the normal Reactor Trip Recovery procedure was implemented and all safety functions were satisfactory. Subsequently, at 2:45 P.M., a fire was reported at the potential transformer outside the protected area. The fire was controlled and allowed to extinguish itself.

The root cause of this event was determined to be an external fault across the porcelain insulator of the synchronizing potential transformer which resulted in a flashover of the insulator. The flashover resulted from a combination of marginal basic insulation level of the transformer contributed to by salt contamination of the insulator.

The following actions were taken by FPL to correct the problem:

1. The synchronizing potential transformer was replaced with a new 900KV BIL rated model of increased strike distance for enhanced insulating capability.
2. The Unit 1 switchyard components were inspected and no other degraded components were found.
3. Schedules were establish to periodically apply silicone coatings to both units synchronizing potential transformers.
4. The main transformer, main generator and isophase bus were inspected with satisfactory results.
5. An upgraded synchronizing potential transformer utilizing a 1050 KV insulation level was installed in the February 1995 Quench Tank In Leakage outage.

Initial corrective actions were completed by October 26, 1994. A total of 9:33 off-line hours were attributed to this event. There were no off-site environmental issues associated with this event.

The cost to replace the transformer and perform the required inspections was approximately $74,000. The corrective actions were performed by FPL employees.

Event: Quench Tank In Leakage

St. Lucie Unit 1

Event date: February 27, 1995

Beginning in December 1994, the rate of in leakage to the quench tank began to trend upward. It soon became evident that the leakage rate would eventually approach the Technical Specification Reactor Coolant System (RCS) leakage limit, requiring a mid-cycle outage to correct the problem. A task team was established to identify contributing factors to the in leakage and develop and implement appropriate corrective actions. On February 27, 1995, St. Lucie Unit 1 was removed from service to implement the corrective actions identified by the task team.

The primary source of in leakage to the quench tank was determined to be associated with leakage from the pressurizer code safety valves. The valves were leaking between their discs and seats. The major contributors to this leakage were:

1. Insufficient margin between normal system operating pressure and the valves lift set point.
2. High ambient temperature.
3. Valve body flexure from thermal stresses during plant heat up.

The following actions were taken by FPL to correct the problem:

1. All three pressurizer code safety valves were replaced.
2. Pressurizer head insulation was modified to improve ambient conditions of the code safety valves.
3. The pressurizer missile shield was removed to improve the ambient conditions of the code safety valves.
4. Pressurizer pressure was raised slowly over a 24 hour period allowing the valves to soak at each step.

A long term solution to code safety valve leakage is addressed in event "Pressurizer Code Safety Valve Alignment Modifications".

A total of 157:58 off-line hours, excluding normal start up, were attributed to this event. St. Lucie Unit 1 was successfully returned to service on March 8, 1995. There were no off site environmental issues associated with this event.

The cost to replace the pressurizer code safety valves as well as modifications to the pressurizer was approximately $896,000. The work was by performed FPL employees as well as Crosby Valve and Gage Co. and Wyle Laboratories.

Event: Turbine Trip During Surveillance Testing

St. Lucie Unit 1

Event date: July 8, 1995

On July 8, 1995, Unit 1 was in Mode One and operating at 100% power. Operations personnel were conducting a scheduled turbine overspeed trip surveillance per approved plant procedures. During the portion of the surveillance that tests a solenoid valve for overspeed protection control, an operator failed to close an isolation valve prior to continuing with the test. Failure to close the valve allowed electro-hydraulic (EH) fluid to drain from the governor and intercept valves when the solenoid valve was opened during a subsequent step. Draining the EH fluid caused closure of the main turbine governor and intercept valves, resulting in a turbine trip followed by an automatic reactor trip.

The root cause of this event was the performance of surveillance test steps out of sequence.

The following actions were taken by FPL to correct the problem:

1. Normal post trip actions were taken to ensure plant equipment responded as designed and operated properly.
2. Normal plant start up activities were performed to return the unit to service.

A total of 50:58 off-line hours were attributed to this event. There were no off site environmental issues associated this event.

There were no repair costs associated with this event.

Event: External Event, Vehicle In Discharge Canal

St. Lucie Unit 1

Event date: July 10, 1995

On July 9, 1995 with Unit 2 at 100% power and Unit 1 in start up Mode Three, a vehicle entered FPL property through an open gate off Highway A1A. Although the entrance was clearly marked with a "NO TRESPASSING VIOLATORS WILL BE PROSECUTED" sign, the driver proceeded east along the access road adjacent to the intake canal. The driver turned north until he encountered a locked gate. After making a U-turn, the vehicle proceeded up and over the berm of the discharge canal, ultimately entering the discharge canal. The occupants of the vehicle exited the vehicle prior to it submerging and climbed up a ladder located on the North side of the discharge headwall.

The vehicle was located inside the discharge pipe approximately 50 feet from the ocean end of the pipe. Flow through the discharge pipe was slowed to allow divers to enter the pipe and re-position the vehicle and extract it from the discharge pipe on July 11, 1995. The vehicle was subsequently towed, by tug boat, to a terminal dock in Ft. Pierce.

The root cause of this event was determined to be the vehicle driver's disregard of a clearly posted no trespassing sign on FPL property at the entrance to the canal area.

A security analysis was conducted of areas within the owner controlled area to determine where enhanced security measures could be implemented to preclude such incidents in the future. One preventative measure identified was to lock all gates which allow access to FPL property.

The introduction of the vehicle into the discharge canal delayed the start up of Unit 1 by 29:45 hours excluding normal start up. The incident did not affect the operation of Unit 2. There were no off site environmental issues resulting from this event. A report of the event was filed with the appropriate State environmental agencies.

The cost to remove the vehicle from the discharge pipe was approximately $37,000 and was accomplished by FPL employees and Underwater Engineering Service, Inc.

Event: External Event, Hurricane Erin

St. Lucie Unit's 1 and 2

Event date: August 1, 1995

On July 31, 1995 at 11:14 A.M., with both St. Lucie nuclear units at 100% power, the National Hurricane Center issued a hurricane warning which encompassed the St. Lucie plant site. On August 1, 1995, information from the National Hurricane Center forecast sustained hurricane force winds at the St. Lucie plant site. In accordance with the Site Emergency Plan, site management directed the commencement of a controlled shut down of St. Lucie Units 1 and 2. St. Lucie unit 1 was taken off line on August 1, 1995 at 2:55 P.M. St. Lucie Unit 2 was taken off line on August 1, 1995 at 11:28 A.M. Both units were shut down by 2:00 P.M.

Hurricane Erin passed approximately 20 miles to the North of the St. Lucie plant on August 2, 1995 at 1:00 A.M. After damage assessment and emergency plan actions were concluded, the decision to return both units to service was made. Unit 2 returned to service on August 5, 1995 at 12:52 A.M. Unit 1's return to service was initially delayed by the failure of the 1A2 Reactor Coolant Pump seal.

The off-line hours directly attributable to Hurricane Erin for both units was 98:19.

The cost incurred for Hurricane Erin St. Lucie plant preparation was approximately $282,000. The preparation efforts were performed by FPL employees and Raytheon Constructors Inc.

Event: 1A2 Reactor Coolant Pump Seal Package Failure

St. Lucie Unit 1

Event date: August 2, 1995

On August 2, 1995, while Unit 1 was in start up Mode Three following a shutdown due to Hurricane Erin, operators detected the 1A2 Reactor Coolant Pump (RCP) lower seal had failed. In accordance with approved procedures, attempts were made to return the seal to service while maintaining the unit in Mode Three. The procedure sequentially de-pressurizes the seal cavities from top to bottom in order to introduce a differential pressure across the leaking seal thereby restaging it. The attempt to restage the lower seal failed. As a result, operators cooled down and de-pressurized the reactor coolant system in accordance with plant operating procedures.

The root cause of the seal failure is currently under investigation.

The following actions were taken by FPL to correct the problem:

1. The 1A2 RCP seal was replaced.
2. Engineering is performing a root cause evaluation of the seal failure.

A total of 129:11 off-line hours, excluding normal plant start up, were attributed to this event. There were no off site environmental issues associated with this event.

The cost to replace the 1A2 RCP seal was approximately $1,184,000. The repair effort was performed by FPL employees and Raytheon Constructors.

Event: Power Operated Relief Valve Failures

St. Lucie Unit 1

Event date: August 9, 1995

On August 9, 1995, Unit 1 was in start up Mode Four following a shut down due to Hurricane Erin. Stroke testing of the Pressurizer Power Operated Relief Valves (PORV) was being performed in accordance with an approved plant procedure. During testing, operators could not confirm that the PORV's were opening as expected. The valves were declared inoperable and a plant cool down and de-pressurization was performed. Both PORV's were removed from the pressurizer. The valves were functionally tested and did not open as expected. The valves were subsequently disassembled and the main disc guides were found to be installed improperly.

The root cause of the PORV inoperability was determined to be improper re-assembly of the PORV's following overhaul during the 1994 refueling outage.

The following actions were taken by FPL to correct the problem:

1. Both PORV's were removed and re-assembled correctly.
2. Changes were made to the Power Operated Relief Valve maintenance procedure to verify, during bench testing, that the main valve disc actuates when test pressure is applied and to add a verification that the main disc guide is installed with the correct orientation.
3. A change was made to the procedure for conducting in service testing on the PORV's to require more positive indication of PORV main valve actuation by using quench tank and pressurize parameters for confirmation during testing.
4. Other activities performed by the same contractor were reviewed. No other equipment operability issues were identified.
5. Unit 2 PORV's were determined not to be susceptible to a similar event; The valve configuration on Unit 2 PORVs does not allow for the main disc guide to be installed improperly.
6. Plant Staff and Engineering will perform a review of post maintenance testing on other safety related equipment to ensure the testing adequately demonstrates component operability.
7. A comprehensive review of and modification to procedures pertaining to control of contractors will be performed.

A total of 145:17 off-line hours, excluding normal plant start up, were attributed to this event. There were no off site environmental issues associated with this event.

The cost to remove, re-assemble and re-install the PORV's was approximately $381,000. The corrective measures were implemented by FPL employees.

Event: Inadvertent Spray Down Of Containment

St. Lucie Unit 1

Event date: August 17, 1995

On August 11, 1995, a containment spray (CS) header control valve failed its stroke test and was declared out of service. Pending repair of the valve, the valve was placed in its safeguards position of open.

On August 17, 1995, with Unit 1 in start up Mode Three, the Emergency Core Cooling System (ECCS) venting procedure for the Low Pressure Safety Injection System (LPSI) was started. As part of that procedure, an operator started the 1A LPSI pump and established a flow path through the Shutdown Cooling System (SDC) heat exchanger. These actions provided a direct flow path from the Refueling Water Tank (RWT) to the "A" CS header and the open header control valve. Approximately 10,000 gallons of borated water was inadvertently sprayed into containment through the "A" CS header using the 1A LPSI pump.

Operators secured the 1A LPSI pump and isolated the 1A SDC heat exchanger and drained the reactor sump to the Aerated Waste Storage Tank.

The root cause of this event was identified as a procedural deficiency in the ECCS venting procedure, which did not require operators to verify that the proper CS header isolation valves were closed prior to recirculating the water in the SDC system.

The following actions were taken by FPL to correct the problem:

1. Plant equipment impacted by the borated water spray was cleaned, inspected and repaired or replaced as required.
2. The ECCS and CS venting procedure was revised to provide limitations on plant conditions during venting.
3. The CS header isolation valve was repaired and returned to normal status.

A total of 343:31 off-line hours were attributed to this event. There were no off site environmental issues associated with this event.

The cost of this event, including containment clean up was approximately $966,000. The clean up effort was performed by FPL employees.

Event: 1B2 EDG Rocker Arm Adjusting Screw Lock Nut

St. Lucie Unit 1

Event date: September 1, 1995

On August 31, 1995, operations personnel were conducting a one hour Emergency Diesel Generator (EDG) surveillance run in accordance with procedures. Unit 1 was in Mode Five following the containment spray incident. After the EDG reached a rated speed of 900 RPM, the 1B EDG tripped on high crankcase pressure from the 1B2 engine. Inspections revealed that the number nine power pack piston and cylinder head had sustained damage due to separation of the exhaust valve head from its stem. The failed valve head, loose within the combustion chamber, punctured the piston and cylinder head. Damage was also observed in several exhaust valve train parts.

The most probable root cause of the EDG failure was the exhaust valve rocker arm adjusting screw lock nut had loosened.

The following actions were taken by FPL to correct the problem:

1. The 1B2 EDG engine was repaired, cleaned and inspected.
2. All EDG engines were inspected for exhaust valve rocker arm lock nut torque.
3. Technical manuals were updated to include a minimum torque check verification of 50 foot pounds for the adjusting screw lock nut.
4. Failed engine components have been sent to the original manufacturer to determine root cause of the equipment failure.

A total of 258:11 off-line hours, commencing on September 1, 1995, were attributed to this event. There were no off site environmental issues associated with this event.

The cost to repair the 1B2 EDG was approximately $289,000. The repair effort was performed by FPL employees and MKW Power Systems, Inc.

Event: Pressurizer Code Safety Valve Flange Leakage

St. Lucie Unit 1

Event date: September 11, 1995

On September 11, 1995, with Unit 1 in start up Mode Three, a Reactor Coolant System leak inspection was performed. During the inspection, it was noted that the inlet flange of Pressurizer Code Safety Valve (PCSV) 1201 was leaking. In order to repair the valve, the unit was cooled down and de-pressurized to Mode Five.

The apparent root cause of the leakage was found to be the use of flexicarb spiral wound model gaskets without the concurrent use of a crush stop to prevent plastic deformation in tongue and groove applications. This results in the gasket material assuming most of the pre load of the flange bolting. In addition, Engineering determined that the procedural torque specification for bolting was excessive for this application.

The following actions were taken by FPL to correct the problem:

1. PCSV 1201, as well as the other two PCSV's, were re-installed with gaskets designed to operate without a crush stop (Kammprofile gaskets).
2. A lower torque value of 500 foot pounds was incorporated into the PCSV maintenance procedure.
3. An improved PCSV bolt up process has been incorporated into maintenance procedures.
4. A review of generic applications of flexicarb gaskets and their misuse is underway.
5. Kammprofile gaskets have been procured for Unit 2 and will be installed during the current Unit 2 outage.

A long term solution to code safety valve leakage is addressed in event "Pressurizer Code Safety Valve Alignment Modifications".

A total of 70:25 off-line hours, excluding normal start up, were attributed to this event. There were no off site environmental issues associated with this event.

The cost to repair the three PCSV's, as well as perform the modifications outlined in event "Pressurizer Code Safety Valve Alignment Modifications" was approximately $190,000. The repair work was performed by FPL employees and Crosby Valve and Gage Co.

Event: 1B Emergency Diesel Generator Hold Down Bolts

St. Lucie Unit 1

Event date: September 19, 1995

On September 19, 1995, during a surveillance of the 1B Emergency Diesel Generator (EDG), an operator found a bolt head broken off.

The failed bolt head was sent to the FPL metallurgical lab for evaluation. Based upon observed field conditions, EDG design knowledge and failure analysis, it was determined the bolt failed under high cycle fatigue. Contributing factors to the fracture were normal vibration energy, the mounting bolt being partially unloaded as a result of the exhaust valve rocker arm adjusting screw lock nut failing (see "1B2 EDG Rocker Arm Adjusting Screw Lock Nut" event) and the bolt being previously machined to remove threads in the base plate area.

The following actions were taken by FPL to correct the problem:

1. The failed bolt was replaced.
2. An ultrasonic evaluation was performed on all bolting on all site EDG engines. No evidence of cracking or shearing was found.
3. All site EDG engine bolt torques were verified.
4. A standard mounting detail will be developed for all eight EDG engines.

A total of 71:27 off-line hours were attributed to this event. There were no off site environmental issues associated with this event.

The cost to replace the failed bolting is included in the "1B2 EDG Rocker Arm Adjusting Screw Lock Nut" event. The repairs were performed by FPL employees.

Event: 1A and 1B EDG Governor Stability

St. Lucie Unit 1

Event date: September 22, 1995

On September 21, 1995, with St. Lucie Unit 1 in Mode Five, preparing for Mode Four, the 1B Emergency Diesel Generator (EDG) was started to perform a test run. After several minutes of operation, the 1B EDG governor experienced load oscillations. On September 22, 1995, the 1A EDG also experienced similar governor load swings during testing.

The root cause of the EDG governor load swings was primarily attributed to problems associated with the motor operated potentiometer within the governor.

The following actions were taken by FPL to correct the problem:

1. The motor operated potentiometer was replaced on both the 1A and 1B EDG'S.
2. The governor amplifier, load sensor and frequency sensor were replaced on the 1A EDG.
3. Adjusted governor controls on both the 1A and 1B EDG's.
4. Cleaned and inspected EDG governor components.

A total of 66:13 off-line hours, commencing on September 22, 1995, were attributed to this event. The 1A EDG was returned to service on September 23, 1995. The 1B EDG was returned to service on September 24, 1995. There were no off site environmental issues associated with this event.

The cost to repair the 1A EDG and the 1B EDG is included in the "1B2 EDG Rocker Arm Adjusting Screw Lock Nut" event. The repair effort was performed by FPL employees.

Event: Pressurizer Code Safety Valve Alignment Modifications

St. Lucie Unit 1

Event date: September 24, 1995

On September 26, 1995, during Unit 1 heat up, instrumentation indicated leakage from Pressurizer Code Safety Valve (PCSV) 1202. Reactor Coolant System (RCS) pressure was reduced and PCSV 1202 appeared to reseat. On September 27, 1995, with (RCS) pressure at 2230 psia, a minimal amount of leakage was identified in PCSV's 1201 and 1202. As RCS pressure increased, the leakage rate accelerated. A unit cool down and de-pressurization was initiated.

The primary root cause of the valve leakage was determined to be operating load stress placed on the valve by associated tail piping.

The following actions were taken by FPL to correct the problem:

1. All three PCSV's were replaced with valves which had recently been refurbished.
2. The tail pipe supports were modified to reduce operating loads placed on the PCSV's.
3. The refurbished PCSV's were installed in locations where the unit operated without leakage in the past.
4. Heat up procedures were revised to allow additional time for associated piping to achieve thermal equilibrium.

The cause of PCSV leakage has been studied in the nuclear industry and by FPL for some time. FPL determined a long term solution to the leakage problems to be the replacement of PCSV's with a newly designed valve. The new valve is manufactured out of forged steel utilizing a block body design which provides greater strength and will make the new valves less susceptible to tail pipe operating stress . The new valves will be installed in Unit 1 during the 1996 refueling outage.

A total of 341:15 off-line hours, commencing on September 24, 1995, excluding normal plant start up, were attributed to this event. St. Lucie Unit 1 was successfully returned to service on October 13, 1995. There were no off site environmental issues associated with this event.

The cost to replace the PCSV's and perform the modifications to the tail pipe supports is included in event "Pressurizer Code Safety Valve Flange Leakage". The repairs were performed by FPL employees and Crosby Valve and Gage Co.

Event: Steam Generator Level Transmitter Failure

St. Lucie Unit 2

Event date: February 21, 1995

On February 21, 1995, Unit 2 was in Mode One at 100% power. At 1:17 PM, Unit 2 automatically tripped due to low water level in the 2A Steam Generator. In accordance with plant procedures, standard post trip and reactor trip activities were performed. Normal steam generator water levels were regained and Unit 2 was stabilized in Mode Three.

The low water level in the 2A Steam Generator was due to a level transmitter which had failed high. The most likely root cause of the level transmitter failure, as determined by the design vendor, was coalescing of microscopic conductive particulates in the fill fluid which acted as a short circuit between the center diaphragm of the transmitter and one of the sensor cell capacity plates.

The following actions were taken by FPL to correct the problem:

1. The level transmitter was replaced with a newly manufactured transmitter.
2. The corresponding level transmitter on the 2B Steam Generator was replaced.
3. The failure was reviewed to prevent similar failures on other plant transmitters.
4. Engineering packages were completed to provide for additional margins in steam generator low level pre-trip alarms.

A total of 78:43 off-line hours were attributed to this event. There were no off site environmental issues associated with this event.

The cost to replace the failed level transmitter was approximately $229,000. The repairs were performed by FPL employees.

Event: Digital Electro-Hydraulic Power Supply Failure

St. Lucie Unit 2

Event date: April 25, 1995

On April 12, 1995, with Unit 2 in Mode One at 100% power, annunciation in the control room indicated trouble with one of the six power supply units within the Digital Electro-Hydraulic (DEH) cabinet. Site personnel investigated and found the output of one of the power supply units was zero. Since the replacement of the power supply unit at full power may have resulted in a unit trip, the plant was taken out of service on April 25, 1995 to replace the DEH power supply unit.

The root cause of the DEH power supply unit failure was determined to be the failure of a resister within the power supply unit. The failure was determined to be an isolated incident as analysis revealed no such failure of this type of power supply in approximately 50 years of industry use.

The following actions were taken by FPL to correct the problem:

1. The DEH power supply unit was replaced along with the associated crow bar circuit and in-line fuse holder.
2. An inspection was made of the remaining power supply units.

A total of 7:21 off-line hours were attributed to this event. St. Lucie Unit 2 was successfully returned to service on April 25, 1995. There were no off site environmental issues associated with this event.

The cost to replace the failed power supply and associated hardware was approximately $4,000. The repairs were performed by FPL employees.

Event: Switchyard Circuit Breaker Failure

St. Lucie Unit 2

Event date: August 4, 1995

With St. Lucie Unit 2 in Mode One during start up after Hurricane Erin, plant operators attempted unsuccessfully to automatically synchronize the main generator to the grid. During a second synchronization attempt, a generator circuit breaker momentarily closed, re-opening when the synchroscope needle indicated the generator was approximately 30 degrees out of phase with the grid's frequency.

The most likely root cause of this event was a slowly opening solenoid operated pilot valve on the pneumatic actuator on a generator circuit breaker. The pilot valve probably had its plug momentarily stick, causing the circuit breaker to operate too slowly and close in after the generator and the grid had gone out of phase.

The following actions were taken by FPL to correct the problem:

1. The pilot valve for the generator circuit breaker was replaced.
2. Troubleshooting on the main generator automatic synchronization circuitry and relays was performed with satisfactory results.
3. Circuit breakers were tested for satisfactory operation.
4. The incident was evaluated for Unit 1 considerations but was determined not to be applicable to the Unit 1 generator.
5. Westinghouse Electric evaluated the potential damage to the main generator and determined that the conditions experienced during the event were within the design ratings of the generator.
6. FPL will replace the air operated pilot valves with a different model during the current Unit 2 refueling outage.

Corrective actions were completed by August 5, 1995. A total of 14:08 off-line hours were attributed to this event. St. Lucie Unit 2 was successfully returned to service on August 5, 1995. There were no off site environmental issues concerning this event.

The cost to replace the pilot valves was approximately $4,000. The corrective actions were performed by FPL employees.

DOCUMENT NO. 1
FLORIDA POWER AND LIGHT COMPANY
REVISED RESPONSE TO STAFF'S THRID SET OF INTERROGATORIES
INTERROGATORY NO. 21 - REVISED

RLW - 2
DOCKET NO. 960001-EI
FPL WITNESS: R. L. WADE
EXHIBIT ___________
PAGES 1 THROUGH 18

FLORIDA PUBLIC SERVICE COMMISSION
DOCKET NO. 960001-EI EXHIBIT NO. 13
COMPANY/WITNESS: FPL Wade
DATE: 8/29/96

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1	Feb 27-95	Quench Tank In Leakage	4	163,667,000	$2,264,639
1	Jul 8-95	Turbine Trip During Surveillance Testing	5	36,050,000	$615,742
1	Jul 10-95	External Event, Vehicle in Discharge Canal	6	25,235,000	$417,900
1 and 2	Aug 1-95	External Event, Hurricane Erin	7	68,571,000	$1,054,361
1	Aug 2-95	1A2 Reactor Coolant Pump Seal Package Failure	8	124,012,000	$2,123,006
1	Aug 9-95	Power Operated Relief Valve Failures	9	134,883,000	$2,577,776

ST LUCIE UNIT NO.	DATE	EVENT	For (a) (b) (c) See Page	(e) REPLACEMENT ENERGY kWh	(f) & (g) COST (see notes 1,2 & 3 below)
1	Aug 17-95	Inadvertent Spray Down of Containment	10	248,024,000	$4,179,840
1	Sep 1-95	1B2 EDG Rocker Arm Adjusting Screw Lock Nut	11	186,739,000	$2,844,879
1	Sep 11-95	Pressurizer Code Safety Valve Flange Leakage	12	124,733,000	$2,086,873
1	Sep 19-95	1B Emergency Diesel Generator Hold Down Bolts	13	51,191,000	$824,809
1	Sep 22-95	1A & 1B EDG Governor Stability	14	48,307,000	$748,007
1	Sep 24-95	Pressurizer Code Safety Valve Alignment Modifications	15	325,892,000	$5,208,977
2	Feb 21-95	Steam Generator Level Transmitter Failure	16	53,878,000	$637,288
2	Apr 25-95	Digital Electro-Hydraulic Power Supply Failure	17	5,456,000	$70,814
2	Aug 4-95	Switchyard Circuit Breaker Failure	18	9,548,000	$186,098

Assumptions:

1) Total KWH replacement energy based upon net to FPL from: a) PSL1 of 776MW per hour less projected forced outage rate and projected maintenance outage rate of 3.1% and 4%, respectively and b) PSL2 of 777 megawatts per hour less projected forced outage rate and projected maintenance outage rate of 9.9% and 2.3%, respectively. The projected outage rates are taken from the Fuel Cost Recovery filing of June 1995. The resultant output (721 and 682 for PSL#1 and PSL#2) was considered the energy to be replaced for each hour the unit was off-line.

2) Total Cost and Fuel Cost are equal since there was no capacity purchased to replace PSL output.

3) The replacement fuel cost based upon the FPL hourly system lambda (cost of next megawatt) adjusted for the decremental block of energy assumed in assumption 1 above. The average cost of PSL energy ($per megawatt hour) was assumed to be $5.58 and $6.75 for PSL#1 and PSL#2 respectively. The PSL cost was subtracted from the adjusted FPL hourly system lambda and was multiplied by the replacement energy.

Event: Potential Transformer

St. Lucie Unit 1

Event date: October 26, 1994

On October 26, 1994, Unit 1 was in Mode 1 and operating at 100% power. At 2:26 P.M, an arc was observed in the area of the 240 KV switchyard near the Unit 1 synchronizing potential transformer. Concurrently, Unit 1 experienced an automatic reactor trip on loss of electrical load predicated by main generator differential current condition. Standard post trip actions were performed, the normal Reactor Trip Recovery procedure was implemented and all safety functions were satisfactory. Subsequently, at 2:45 P.M., a fire was reported at the potential transformer outside the protected area. The fire was controlled and allowed to extinguish itself.

The root cause of this event was determined to be an external fault across the porcelain insulator of the synchronizing potential transformer which resulted in a flashover of the insulator. The flashover resulted from a combination of marginal basic insulation level of the transformer contributed to by salt contamination of the insulator.

A review of FPL's distribution system revealed no prior inservice failures of this type model potential transformer. The potential transformers were routinely inspected and cleaned during refueling outages. A silicone maintenance coating program was in place prior to this event but applied only to breaker bushings. Since there was no vendor recommendation to coat potential transformers nor any previous failures, the potential transformers were not included in the maintenance coating program. After this event, the potential transformers were added to the maintenance silicone coating program.

The following actions were taken by FPL to correct the problem:

1. The synchronizing potential transformer was replaced with a new 900KV basic insulation level rated model of increased strike distance for enhanced insulating capability.
2. The Unit 1 switchyard components were inspected and no other degraded components were found.
3. Schedules were establish to periodically apply silicone coatings to both units synchronizing potential transformers.
4. The main transformer, main generator and isophase bus were inspected with satisfactory results.
5. An upgraded synchronizing potential transformer utilizing a 1050 KV insulation level was installed during the February 1995 Quench Tank In Leakage outage.

Initial corrective actions were completed by October 26, 1994. A total of 9:33 off-line hours were attributed to this event. There were no off-site environmental issues associated with this event.

The cost to replace the transformer and perform the required inspections was approximately $74,000. The corrective actions were performed by FPL employees.

Event: Quench Tank In Leakage

St. Lucie Unit 1

Event date: February 27, 1995

Beginning in December 1994, the rate of in leakage to the quench tank began to trend upward. It soon became evident that the leakage rate would eventually approach the Technical Specification Reactor Coolant System (RCS) leakage limit, requiring a mid-cycle outage to correct the problem. A task team was established to identify contributing factors to the in leakage and develop and implement appropriate corrective actions. On February 27, 1995, St. Lucie Unit 1 was removed from service to implement the corrective actions identified by the task team.

The primary source of in leakage to the quench tank was determined to be associated with leakage from the Pressurizer Code Safety Valves (PCSV). The valves were leaking between their discs and seats. The major contributors to this leakage were:

1. Insufficient margin between normal system operating pressure and the valves lift set point.
2. High ambient temperature.
3. Valve body flexure from thermal stresses during plant heat up.

The following actions were taken by FPL to correct the problem:

1. All three PCSV's were replaced.
2. Pressurizer head insulation was modified to improve ambient conditions of the PCSV's.
3. The pressurizer missile shield was removed to improve the ambient conditions of the PCSV's.
4. Pressurizer pressure was raised slowly over a 24 hour period allowing the valves to soak at each step.

The cause of and corrective actions for PCSV leakage has been an issue in the nuclear industry, as well as, with FPL for some time. When new and following refurbishments, which are performed periodically, these valves operate to their design specification. FPL determined a long term solution to the leakage problems to be the replacement of PCSV's with a newly designed valve. The new valve is manufactured out of forged steel utilizing a block body design which provides greater strength and makes the new valves less susceptible to tail pipe operating stress. The new valves were installed in Unit 1 in June 1996. The new valves for Unit 2 will be installed during the next refueling outage currently scheduled for April 1997.

A total of 226:49 off-line hours, including 68:51 hours for normal start up, were attributed to this event. St. Lucie Unit 1 was successfully returned to service on March 8, 1995. There were no off site environmental issues associated with this event.

The cost to replace the pressurizer code safety valves as well as modifications to the pressurizer was approximately $820,000. The work was performed by FPL employees as well as Crosby Valve and Gage Co. and Wyle Laboratories.

Event: Turbine Trip During Surveillance Testing

St. Lucie Unit 1

Event date: July 8, 1995

On July 8, 1995, Unit 1 was in Mode One and operating at 100% power. Operations personnel were conducting a scheduled turbine overspeed trip surveillance per approved plant procedures. During the portion of the surveillance that tests a solenoid valve for overspeed protection control, an operator failed to close an isolation valve prior to continuing with the test. Failure to close the valve allowed electro-hydraulic (EH) fluid to drain from the governor and intercept valves when the solenoid valve was opened during a subsequent step. Draining the EH fluid caused closure of the main turbine governor and intercept valves, resulting in a turbine trip followed by an automatic reactor trip.

The root cause of this event was the performance of surveillance test steps out of sequence.

The following actions were taken by FPL to correct the problem:

1. Normal post trip actions were taken to ensure plant equipment responded as designed and operated properly.
2. Normal plant start up activities were performed to return the unit to service.

The employee involved in the surveillance has been an FPL employee for thirteen years. He entered the St. Lucie Plant Operations department career path in September 1986 as an Associate Nuclear Plant Operator. After successfully completing all requirements of the career path, he was sequentially promoted through the Nuclear Plant Operator classification to his current position of Senior Nuclear Plant Operator in September 1989. The Senior Nuclear Plant Operator watch station responsibilities include the operation and monitoring of various plant systems and components.

A total of 50:58 off-line hours were attributed to this event. There were no off site environmental issues associated this event.

There were no repair costs associated with this event. All reviews and analyses were performed by FPL employees.

Event: External Event, Vehicle In Discharge Canal

St. Lucie Unit 1

Event date: July 10, 1995

On July 9, 1995 with Unit 2 at 100% power and Unit 1 in start up Mode Three, a vehicle entered FPL property through an open gate off Highway A1A. Although the entrance was clearly marked with a "NO TRESPASSING VIOLATORS WILL BE PROSECUTED" sign, the driver proceeded east along the access road adjacent to the intake canal. The driver turned north until he encountered a locked gate. After making a U-turn, the vehicle proceeded up and over the berm of the discharge canal, ultimately entering the discharge canal. The occupants of the vehicle exited the vehicle prior to it submerging and climbed up a ladder located on the North side of the discharge headwall.

The vehicle was located inside the discharge pipe approximately 50 feet from the ocean end of the pipe. Flow through the discharge pipe was slowed to allow divers to enter the pipe and re-position the vehicle and extract it from the discharge pipe on July 11, 1995. The vehicle was subsequently towed, by tug boat, to a terminal dock in Ft. Pierce.

The root cause of this event was determined to be the vehicle driver's disregard of a clearly posted no trespassing sign on FPL property at the entrance to the canal area. Due to a large number of employees requiring entry into and out of this area to perform such duties as surveys for environmental and biological studies, the gate was routinely left unlocked.

A security review was conducted of areas within the owner controlled area to determine where enhanced security measures could be implemented to preclude such incidents in the future. This review led to a decision to lock the gates in the area where the incident occurred, thus denying access to FPL property.

The introduction of the vehicle into the discharge canal delayed the start up of Unit 1 a total of 34:13 hours, including 4:28 hours for normal start up. The incident did not effect the operation of Unit 2. There were no off site environmental issues resulting from this event. A report of the event was filed with the appropriate State environmental agencies.

The cost to remove the vehicle from the discharge pipe was approximately $39,000 and was accomplished by FPL employees and Underwater Engineering Service, Inc.

Event: External Event, Hurricane Erin

St. Lucie Unit's 1 and 2

Event date: August 1, 1995

On July 31, 1995 at 11:14 A.M., with both St. Lucie nuclear units at 100% power, the National Hurricane Center issued a hurricane warning which encompassed the St. Lucie plant site. On August 1, 1995, information from the National Hurricane Center forecast sustained hurricane force winds at the St. Lucie plant site. In accordance with the Site Emergency Plan, site management directed the commencement of a controlled shut down of St. Lucie Units 1 and 2. St. Lucie unit 1 was taken off line on August 1, 1995 at 2:55 P.M. St. Lucie Unit 2 was taken off line on August 1, 1995 at 11:28 A.M. Both units were shut down by 2:00 P.M.

Hurricane Erin passed approximately 20 miles to the North of the St. Lucie plant on August 2, 1995 at 1:00 A.M. After damage assessment and emergency plan actions were concluded, the decision to return both units to service was made. Unit 2 returned to service on August 5, 1995 at 12:52 A.M. Unit 1's return to service was initially delayed by the failure of the 1A2 Reactor Coolant Pump seal.

The off-line hours directly attributable to Hurricane Erin for both units was 98:19.

The cost incurred for Hurricane Erin St. Lucie plant preparation was approximately $281,000. The preparation efforts were performed by FPL employees and Raytheon Constructors Inc.

Event: 1A2 Reactor Coolant Pump Seal Package Failure

St. Lucie Unit 1

Event date: August 2, 1995

On August 2, 1995, while Unit 1 was in start up Mode Three following a shutdown due to Hurricane Erin, operators detected the 1A2 Reactor Coolant Pump (RCP) lower seal had failed. In accordance with approved procedures, attempts were made to return the seal to service while maintaining the unit in Mode Three. The procedure sequentially de-pressurizes the seal cavities from top to bottom in order to introduce a differential pressure across the leaking seal thereby restaging it. The attempt to restage the lower seal failed. As a result, operators cooled down and de-pressurized the reactor coolant system in accordance with plant operating procedures.

After data gathering and analysis, it was determined that there was not a clear root cause for the failure. The following are considered the most likely causes:

1. Misalignment between rotating shaft/seal and stationary seal components.
2. Reactor Coolant System (RCS) pressure/temperature transient.
3. Debris in the RCS.
4. Pump hydraulic instability.

To restore the unit to service, the seal was replaced.

A total of 171:36 off-line hours, including 42:25 hours for normal plant start up, were attributed to this event. There were no off site environmental issues associated with this event.

The cost to replace the 1A2 RCP seal was approximately $1,100,000. The repair effort was performed by FPL employees and Raytheon Constructors.

Event: Power Operated Relief Valve Failures

St. Lucie Unit 1

Event date: August 9, 1995

On August 9, 1995, Unit 1 was in start up Mode Four following a shut down due to Hurricane Erin. Stroke testing of the Pressurizer Power Operated Relief Valves (PORV) was being performed in accordance with an approved plant procedure. During testing, operators could not confirm that the PORV's were opening as expected. The valves were declared inoperable and a plant cool down and de-pressurization was performed. Both PORV's were removed from the pressurizer. The valves were functionally tested and did not open as expected. The valves were subsequently disassembled and the main disc guides were found to be installed improperly.

The root cause of the PORV inoperability was determined to be improper re-assembly of the PORV's following overhaul during the 1994 refueling outage. The overhaul was performed by Furmanite employees, a contractor used by FPL to perform valve maintenance.

The following actions were taken by FPL to correct the problem:

1. Both PORV's were removed and re-assembled correctly. No damage or problems were noted.
2. Changes were made to the Power Operated Relief Valve maintenance procedure to verify, during bench testing, that the main valve disc actuates when test pressure is applied and to add a verification that the main disc guide is installed with the correct orientation.
3. A change was made to the procedure for conducting in service testing on the PORV's to require more positive indication of PORV main valve actuation by using quench tank and pressure parameters for confirmation during testing.
4. Other activities performed by Furmanite were reviewed. No other equipment operability issues were identified.
5. Unit 2 PORV's were determined not to be susceptible to a similar event; The valve configuration on Unit 2 PORV's does not allow for the main disc guide to be installed improperly.
6. Plant Staff and Engineering performed a review of existing procedures governing post maintenance testing on other safety related equipment to ensure the testing adequately demonstrates component operability. All post maintenance procedures reviewed were found to adequately address and demonstrate component operability.
7. A comprehensive review of and modification to procedures pertaining to control of contractors was performed.

A total of 188:28 off-line hours, including 43:11 hours for normal plant start up, were attributed to this event. There were no off site environmental issues associated with this event.

The cost to remove, re-assemble and re-install the PORV's was approximately $381,000. The corrective measures were implemented by FPL employees.

Event: Inadvertent Spray Down Of Containment

St. Lucie Unit 1

Event date: August 17, 1995

On August 11, 1995, a containment spray (CS) header control valve failed its stroke test and was declared out of service. Pending repair of the valve, the valve was placed in its safeguards position of open.

On August 17, 1995, with Unit 1 in start up Mode Three, the Emergency Core Cooling System (ECCS) venting procedure for the Low Pressure Safety Injection System (LPSI) was started. As part of that procedure, an operator started the 1A LPSI pump and established a flow path through the Shutdown Cooling System (SDC) heat exchanger. These actions provided a direct flow path from the Refueling Water Tank (RWT) to the "A" CS header and the open header control valve. Approximately 10,000 gallons of borated water was inadvertently sprayed into containment through the "A" CS header using the 1A LPSI pump.

Operators secured the 1A LPSI pump and isolated the 1A SDC heat exchanger and drained the reactor sump to the Aerated Waste Storage Tank.

The root cause of this event was identified as a procedural deficiency in the ECCS venting procedure, which did not require operators to verify that the proper CS header isolation valves were closed prior to recirculating the water in the SDC system.

The following actions were taken by FPL to correct the problem:

1. Plant equipment impacted by the borated water spray was cleaned, inspected and repaired or replaced as required.
2. The ECCS and CS venting procedure was revised to provide limitations on plant conditions during venting.
3. The CS header isolation valve was repaired and returned to normal status.

The PSL Operations department team involved in the venting procedure consisted of two Reactor Control Operators, a Senior Reactor Control Operator and an Assistant Nuclear Plant Supervisor (ANPS). All of these positions are licensed operator positions. The ANPS is a supervisory position responsible for coordinating the activities of their assigned unit.

A total of 343:31 off-line hours were attributed to this event. There were no off site environmental issues associated with this event.

The cost of this event, including containment clean up was approximately $899,000. The clean up effort was performed by FPL employees.

Event: 1B2 EDG Rocker Arm Adjusting Screw Lock Nut

St. Lucie Unit 1

Event date: September 1, 1995

On August 31, 1995, operations personnel were conducting a one hour Emergency Diesel Generator (EDG) surveillance run in accordance with procedures. Unit 1 was in Mode Five following the containment spray incident. After the EDG reached a rated speed of 900 RPM, the 1B EDG tripped on high crankcase pressure from the 1B2 engine. Inspections revealed that the number nine power pack piston and cylinder head had sustained damage due to separation of the exhaust valve head from its stem. The failed valve head, loose within the combustion chamber, punctured the piston and cylinder head. Damage was also observed in several exhaust valve train parts.

There is no absolute conclusive evidence which supports a specific root cause. The two most probable root causes are the rocker arm lash adjuster stuck in mid stroke or the rocker arm lash adjuster lock nut backed off.

The EDG's are inspected every eighteen months as part of the standard maintenance program. The inspections have historically been performed by the original equipment manufacturer, MKW Power Systems, Inc.

The following actions were taken by FPL to correct the problem:

1. The 1B2 EDG engine was repaired, cleaned and inspected.
2. All EDG engines were inspected for exhaust valve rocker arm lock nut torque. All lock nuts inspected met the minimum foot pound specification.
3. Technical manuals were updated to include a minimum torque check verification of 80 foot pounds for the adjusting screw lock nut.
4. Failed engine components were sent to the original manufacturer to determine root cause of the equipment failure. Although no concrete evidence exists, the original equipment manufacturer believes the rocker arm lash adjuster stuck in mid stroke. There was no evidence of a manufacturing defect.
5. The lash adjuster plunger will be checked for free rotation during routine inspections.

The corrective actions taken by FPL encompass both possible root causes and should prevent a reoccurrence of this problem.

A total of 258:11 off-line hours, commencing on September 1, 1995, were attributed to this event. There were no off site environmental issues associated with this event.

The cost to repair the 1B2 EDG was approximately $289,000. The repair effort was performed by FPL employees and MKW Power Systems, Inc.

Event: Pressurizer Code Safety Valve Flange Leakage

St. Lucie Unit 1

Event date: September 11, 1995

On September 11, 1995, with Unit 1 in start up Mode Three, a Reactor Coolant System leak inspection was performed. During the inspection, it was noted that the inlet flange of Pressurizer Code Safety Valve (PCSV) 1201 was leaking. In order to repair the valve, the unit was cooled down and de-pressurized to Mode Five.

The apparent root cause of the leakage was found to be the use of flexicarb spiral wound model gaskets without the concurrent use of a crush stop to prevent plastic deformation in tongue and groove applications. This results in the gasket material assuming most of the pre load of the flange bolting. In addition, Engineering determined that the torque specification, developed by FPL, for the Unit 1 bolting was excessive for this application. Flexicarb spiral wound model gaskets were introduced over a period of time as a non-asbestos containing substitute for original plant equipment gaskets that contained asbestos. This change out is part of FPL's asbestos abatement program.

The following actions were taken by FPL to correct the problem:

1. PCSV 1201, as well as the other two PCSV's, were re-installed with gaskets designed to operate without a crush stop (Kammprofile gaskets).
2. A lower torque value of 500 foot pounds was incorporated into the PCSV maintenance procedure.
3. An improved PCSV bolt up process has been incorporated into maintenance procedures.
4. A review of generic applications of spiral wound gaskets without crush stops and their misuse is underway. This review is scheduled to be completed by October 30, 1996. Preliminary indication is there are a limited number of applications where spiral wound gaskets may be in use.
5. Kammprofile gaskets were installed in Unit 2 during the Fall 1995 refueling outage.

The cause of and corrective actions for PCSV leakage has been an issue in the nuclear industry, as well as, with FPL for some time. When new and following refurbishments, which are performed periodically, these valves operate to their design specification. FPL determined a long term solution to the leakage problems to be the replacement of PCSV's with a newly designed valve. The new valve is manufactured out of forged steel utilizing a block body design which provides greater strength and makes the new valves less susceptible to tail pipe operating stress. The new valves were installed in Unit 1 in June 1996. The new valves for Unit 2 will be installed during the next refueling outage currently scheduled for April 1997.

A total of 173:12 off-line hours, including 102:47 hours for normal start up, were attributed to this event. There were no off site environmental issues associated with this event.

The cost to repair the three PCSV's, as well as perform the modifications outlined in event "Pressurizer Code Safety Valve Alignment Modifications" was approximately $190,000. The repair work was performed by FPL employees and Crosby Valve and Gage Co.

Event: 1B Emergency Diesel Generator Hold Down Bolts

St. Lucie Unit 1

Event date: September 19, 1995

On September 19, 1995, during a surveillance of the 1B Emergency Diesel Generator (EDG), an operator found a bolt head broken off. The failed bolt head was sent to the FPL metallurgical lab for evaluation. Based upon observed field conditions, EDG design knowledge and failure analysis, it was determined the bolt failed under high cycle fatigue. Contributing factors to the fracture were normal vibration energy, the mounting bolt being partially unloaded as a result of the exhaust valve rocker arm adjusting screw lock nut failing (see "1B2 EDG Rocker Arm Adjusting Screw Lock Nut" event) and the bolt being previously machined to remove threads in the base plate area.

The following actions were taken by FPL to correct the problem:

1. The failed bolt was replaced.
2. An ultrasonic evaluation was performed on all EDG engine mounting bolts. No evidence of cracking or shearing was found.
3. The torque was verified on all EDG engine mounting bolts.

A total of 71:27 off-line hours were attributed to this event. There were no off site environmental issues associated with this event.

The cost to replace the failed bolting is included in the "1B2 EDG Rocker Arm Adjusting Screw Lock Nut" event. The repairs were performed by FPL employees.

Event: 1A and 1B EDG Governor Stability

St. Lucie Unit 1

Event date: September 22, 1995

On September 21, 1995, with St. Lucie Unit 1 in Mode Five, preparing for Mode Four, the 1B Emergency Diesel Generator (EDG) was started to perform a test run. After several minutes of operation, the 1B EDG governor experienced load oscillations. On September 22, 1995, the 1A EDG also experienced similar governor load swings during testing.

The root cause of the EDG governor load swings was primarily attributed to problems associated with the motor operated potentiometer within the governor.

The following actions were taken by FPL to correct the problem:

1. The motor operated potentiometer was replaced, like for like, on both the 1A and 1B EDG'S.
2. The governor amplifier, load sensor and frequency sensor were replaced on the 1A EDG.
3. Adjusted governor controls on both the 1A and 1B EDG's.
4. Cleaned and inspected EDG governor components.

The motor operated potentiometer is physically inspected every eighteen months as part of the standard maintenance program. FPL has adopted a nine month governor cabinet inspection which includes the motor operated potentiometer and has optimized governor system tuning. FPL is also analyzing a proposal to replace the existing governor electronic system with a new upgraded production system.

A total of 66:13 off-line hours, commencing on September 22, 1995, were attributed to this event. The 1A EDG was returned to service on September 23, 1995. The 1B EDG was returned to service on September 24, 1995. There were no off site environmental issues associated with this event.

The cost to repair the 1A EDG and the 1B EDG is included in the "1B2 EDG Rocker Arm Adjusting Screw Lock Nut" event. The repair effort was performed by FPL employees.

Event: Pressurizer Code Safety Valve Alignment Modifications

St. Lucie Unit 1

Event date: September 24, 1995

On September 26, 1995, during Unit 1 heat up, instrumentation indicated leakage from Pressurizer Code Safety Valve (PCSV) 1202. Reactor Coolant System (RCS) pressure was reduced and PCSV 1202 appeared to reseat. On September 27, 1995, with (RCS) pressure at 2230 psia, a minimal amount of leakage was identified in PCSV's 1201 and 1202. As RCS pressure increased, the leakage rate accelerated. A unit cool down and de-pressurization was initiated.

The primary root cause of the valve leakage was determined to be operating load stress placed on the valve by associated tail piping. This piping configuration has been present since original construction of St. Lucie Unit 1.

The following actions were taken by FPL to correct the problem:

1. All three PCSV's were replaced with valves which had recently been refurbished.
2. The tail pipe supports were modified to reduce operating loads placed on the PCSV's.
3. The refurbished PCSV's were installed in locations where the unit operated without leakage in the past.
4. Heat up procedures were revised to allow additional time for associated piping to achieve thermal equilibrium.

The cause of and corrective actions for PCSV leakage has been an issue in the nuclear industry, as well as, with FPL for some time. When new and following refurbishments, which are performed periodically, these valves operate to their design specification. FPL determined a long term solution to the leakage problems to be the replacement of PCSV's with a newly designed valve. The new valve is manufactured out of forged steel utilizing a block body design which provides greater strength and makes the new valves less susceptible to tail pipe operating stress. The new valves were installed in Unit 1 in June 1996. The new valves for Unit 2 will be installed during the next refueling outage currently scheduled for April 1997.

A total of 452:08 off-line hours, commencing on September 24, 1995, including 110:53 hours for normal plant start up, were attributed to this event. St. Lucie Unit 1 was successfully returned to service on October 13, 1995. There were no off site environmental issues associated with this event.

The cost to replace the PCSV's and perform the modifications to the tail pipe supports is included in event "Pressurizer Code Safety Valve Flange Leakage". The repairs were performed by FPL employees and Crosby Valve and Gage Co.

Event: Steam Generator Level Transmitter Failure

St. Lucie Unit 2

Event date: February 21, 1995

On February 21, 1995, Unit 2 was in Mode One at 100% power. At 1:17 PM, Unit 2 automatically tripped due to low feedwater level in the 2A Steam Generator. In accordance with plant procedures, standard post trip and reactor trip activities were performed. Normal steam generator water levels were regained and Unit 2 was stabilized in Mode Three.

The low feedwater level in the 2A Steam Generator was due to a level transmitter which had failed. The most likely root cause of the level transmitter failure, as determined by the design vendor, was contaminates in the sensing element of the transmitter.

The following actions were taken by FPL to correct the problem:

1. The level transmitter was replaced with a newly manufactured transmitter. The manufacturer has made several improvements in the manufacturing process to reduce the likelihood of contaminates in the sensing cell.
2. The corresponding level transmitter on the 2B Steam Generator was also replaced.
3. The failure was reviewed to prevent similar failures on other plant transmitters. It was determined that the transmitter problem was a random failure. The manufacturer has made several improvements to the transmitter to reduce the possibility of future failures.
4. Engineering packages were completed to provide for additional margins in steam generator low level pre-trip alarms.

A total of 78:43 off-line hours were attributed to this event. There were no off site environmental issues associated with this event.

The cost to replace the failed level transmitter was approximately $223,000. The repairs were performed by FPL employees.

Event: Digital Electro-Hydraulic Power Supply Failure

St. Lucie Unit 2

Event date: April 25, 1995

On April 12, 1995, with Unit 2 in Mode One at 100% power, annunciation in the control room indicated trouble with one of the six power supply units within the Digital Electro-Hydraulic (DEH) cabinet. Site personnel investigated and found the output of one of the power supply units was zero. Since the replacement of the power supply unit at full power may have resulted in a unit trip, the plant was taken out of service on April 25, 1995 to replace the DEH power supply unit.

The root cause of the DEH power supply unit failure was determined to be the failure of a resister within the power supply unit. The failure was determined to be an isolated incident as analysis revealed no such failure of this type of power supply in approximately 50 years of industry use.

The following actions were taken by FPL to correct the problem:

1. The DEH power supply unit was replaced along with the associated crow bar circuit and in-line fuse holder.
2. An inspection was made of the remaining power supply units.

A total of 7:21 off-line hours were attributed to this event. St. Lucie Unit 2 was successfully returned to service on April 25, 1995. There were no off site environmental issues associated with this event.

The cost to replace the failed power supply and associated hardware was approximately $4,000. The repairs were performed by FPL employees.

Event: Switchyard Circuit Breaker Failure

St. Lucie Unit 2

Event date: August 4, 1995

With St. Lucie Unit 2 in Mode One during start up after Hurricane Erin, plant operators attempted unsuccessfully to automatically synchronize the main generator to the grid. During a second synchronization attempt, a generator circuit breaker momentarily closed, re-opening when the synchroscope needle indicated the generator was approximately 30 degrees out of phase with the grid's frequency.

The most likely root cause of this event was a slowly opening solenoid operated pilot valve on the pneumatic actuator on a generator circuit breaker. The pilot valve probably had its plug momentarily stick, causing the circuit breaker to operate too slowly and close in after the generator and the grid had gone out of phase.

The following actions were taken by FPL to correct the problem:

1. The pilot valve for the generator circuit breaker was replaced.
2. Troubleshooting on the main generator automatic synchronization circuitry and relays was performed with satisfactory results.
3. Circuit breakers were tested for satisfactory operation.
4. The incident was evaluated for Unit 1 considerations but was determined not to be applicable to the Unit 1 generator.
5. Westinghouse Electric evaluated the potential damage to the main generator and determined that the conditions experienced during the event were within the design ratings of the generator.
6. Replaced the air operated pilot valves with a different model during the Fall 1995 Unit 2 refueling outage.

Corrective actions were completed by August 5, 1995. A total of 14:08 off-line hours were attributed to this event. St. Lucie Unit 2 was successfully returned to service on August 5, 1995. There were no off site environmental issues concerning this event.

The cost to replace the original pilot valves was approximately $4,000. The corrective actions were performed by FPL employees.